A. Glossary and Acronyms

To aid in understanding and comprehension, the glossary and acronym entries in this appendix clarify the meaning of terms and concepts used throughout the *PSIP Update Report: December 2016*.

A

Adequacy of Supply (AOS)

The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Advanced Inverter

A smart inverter capable of being interconnected to the utility (via two-way communications) and controlled by it.

Agricultural A–E Land Classification

The Land Study Bureau (LSB) of the University of Hawai‘i, together with the United States Department of Agricultural soil survey, developed an overall master productivity rating for Hawai‘i’s agricultural land. The productivity rating of land is based on a productivity formula that multiplies the following five percentage indexes:

a = percentage rating for the general character of the soil profile
b = percentage rating for the texture of the surface horizon
c = percentage rating for the slope of the land
x = percentage rating for salinity, soil reaction, damaging winds, erosion, etc.
y = percentage rating for rainfall

This overall productivity rating ranged from "A", very good, to "E", not suitable. Only A, B, and C classified land is deemed suitable for agriculture. The classifications are essentially based on soil quality. Higher percentage ratings means more highly favorable agricultural land. Thus, the range of ratings for agricultural A through E land is :

A = 85–100
B = 70–84
C = 55–69
D = 30–54
E = 0–29

Alternating Current (AC)

An electric current whose flow of electric charge periodically reverses direction. In Hawai'i, the mainland United States, and in many other developed countries, AC is the form in which electric power is delivered to businesses and residences. The usual waveform of an AC power circuit is a sine wave. In Hawai'i and the mainland United States, the usual power system frequency of 60 hertz (1 hertz (Hz) = 1 cycle per second).

Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the electric system in accordance with good utility practice.

As-Available Renewable Energy

See Variable Renewable Energy on page A-38.

Automatic Generation Control (AGC)

A process for adjusting demand and resources from a central location to help maintain frequency. AGC helps balance supply and demand.

Avoided Costs

The costs that utility customers would avoid by having the utility purchase capacity or energy from another source (for example, energy storage or demand response) or from a third party, compared to having the utility generate the electricity itself. Avoided costs comprise two components:

- Avoided capacity costs, which includes avoided capital costs (for example, return on investment, depreciation, and income taxes) and avoided fixed operation and maintenance costs.
- Avoided energy costs, which includes avoided fuel costs and avoided variable operation and maintenance costs.

B

Baseload

The minimum electric or thermal load that is supplied continuously over a period of time. (See also Load, Electric on page A-20.)

Baseload Capacity

See Capacity, Generating on page A-4.

Baseload Generation

The production of energy at a constant rate, to support the system's baseload.

Battery Energy Storage Systems (BESS)

Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, or other utility or customer functions. (See also Energy Storage on page A-12.)

Black Start Resource

A generating unit and its associated set of equipment that can be started without system support or can remain energized without connection to the remainder of the system, and that has the ability to energize a bus, thus meeting a restoration plan's needs for real and reactive power capability, frequency and voltage control, and is included in the restoration plan.

British Thermal Unit (Btu)

A unit of energy equal to about 1055 joules that describes the energy content of fuels. A Btu is the amount of heat required to raise the temperature of 1 pound of water by 1°F at a constant atmospheric pressure. When measuring electricity, the proper unit would be Btu per hour (or Btu/h) although this is generally abbreviated to just Btu. The term MBtu means a thousand Btu; the term MMBtu means a million Btu.

C

Capacitor

A device used to correct AC voltage so that the voltage is in phase with the AC current. Capacitors are typically installed in substations and on distribution system poles, at locations where local voltage correction can reduce system current flow, reducing losses and improves efficiency.

Capacity

The MW rating of the unit. Capacity must be assured for at least four hours and controllable during the 24-hour day.

Capacity Factor (cf)

The ratio of the average operating load of an electric power generating unit for a period of time to the capacity rating of the unit during that period of time.

Capacity, Generating

The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of an electric generating plant. It is the maximum power that a machine or system can produce or carry under specified conditions, usually expressed in kilowatts or megawatts. Capacity is an attribute of an electric generating plant that does not depend on how much it is used. Types of capacity include the following.

Baseload Capacity: Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Baseload capacity typically operates at high annual capacity factors, for example greater than 60%. Island systems experience lower capacity factors because output is often reduced to accommodate lower demand periods and variable energy production.

Firm Capacity: Capacity that is intended to be available at all times during the period covered by a commitment, even under adverse conditions.

Installed Capacity (ICAP): The total capacity of all generators able to serve load in a given power system. Also called ICAP, the total wattage of all generation resources to serve a given service or control area.

Intermediate Capacity: Flexible generators able to efficiently vary their output across a wide band of loading conditions. Also known as Cycling Capacity. Typically annual capacity factors for intermediate duty generating units range from 20% to 60%. Island systems experience lower capacity factors because output is often reduced to accommodate lower demand periods and variable energy production.

Net Capacity: The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.

Peaking and Emergency Capacity: Generators typically called on for short periods of time during system peak load conditions or as replacement resources following contingencies. Annual capacity factors for peaking generation are typically less than 20%.

Capital Expenditures

Funds expended by a utility to construct, acquire or upgrade physical assets (generating plants, energy storage devices, transmission plant, distribution plant, general plant, major software systems, or IT infrastructure). Capital expenditures for a given asset include funds expended for the acquisition and development of land related to the asset, obtaining permits and approvals related to the asset, environmental and engineering studies specifically related to construction of the asset, engineering design of the asset, procurement of materials for the asset, construction of the asset, and startup activities related to the asset. Capital expenditures may be associated with a new asset or an existing asset (that is, renovations, additions, upgrades, and replacement of major components).

Carbon Dioxide (CO_2)

A greenhouse gas produced when carbon-based fossil fuels are combusted.

Combined Cycle (CC)

A combination of combustion turbine- and steam turbine-driven electrical generators, where the combustion turbine exhaust is passed through a heat recovery waste heat boiler which, in turn, produces steam which drives the steam turbine. There are a number of possible configurations for combined cycle units.

3x1 Combined-Cycle: A configuration in which there are three combustion turbines, three heat recovery waste heat boilers, and one steam turbine. Each combustion turbine produces heat for a single waste heat boiler, which in turn produces steam that is directed to the single steam turbine.

Dual-Train Combined-Cycle (DTCC): A configuration in which there are two combustion turbines, two heat recovery waste heat boilers, and one steam turbine. Each combustion turbine and waste heat boiler combination produces steam that is directed to the single steam turbine. Sometimes referred to as a 2x1 combined-cycle.

Single-Train Combined-Cycle (STCC): A configuration in which there is one combustion turbine, one heat recovery waste heat boiler, and one steam turbine. Sometimes referred to as a 1x1 combined-cycle.

Combined Heat and Power (CHP)

The simultaneous production of electric energy and useful thermal energy for industrial or commercial heating or cooling purposes. The Energy Information Administration (EIA) has adopted this term in place of cogeneration.

Combustion Turbine (CT)

Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power; also commonly referred to as a gas turbine (GT). Combustion turbines typically use natural gas or liquid petroleum fuels to operate.

Concentrated Solar Thermal Power (CSP)

A technology that uses mirrors to concentrate solar energy to drive traditional steam turbines or engines that create electricity. A CSP plant can store this energy until needed to meet demand.

Conductor Sag

The distance between the connection point of a conductor (transmission and distribution line) and the lowest point of the line.

Connected Load

See Load, Electric on page A-20.

Contingency Reserves

The reserves deployed to meet contingency disturbance requirements, typically based upon the largest single contingency on each island. Contingency reserves are comprised of fast frequency responses (FFR1 and FFR2) and primary frequency response. In the Hawaiian Electric Companies' system, contingency reserves are automatically initiated.

Critical Peak Incentive (CPI) Program

A DR capacity grid service capable of providing peak load reduction during emergency situations when insufficient generation resources are available. The current Commercial Direct Load Control program could be re-classified under this program as part of the initial migration to a redeveloped DR portfolio.

Customer Grid Supply (CGS)

A program where customers receive a Commission-approved credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid. Customer Grid Supply is one of two programs (the other being Customer Self Supply) that replaced the Net Energy Metering (NEM) program.

Customer Self Supply (CSS)

A program intended only for solar PV installations that are designed to not export any electricity to the grid. Customers are not compensated for any export of energy. Customer Self Supply is one of two programs (the other being Customer Grid Supply) that replaced the Net Energy Metering (NEM) program.

Curtailment

Cutting back on variable resources to keep generation and consumption of electricity in balance.

Cycling

The operation of generating units at varying load levels (including on/off and low load variations), in response to changes in system load requirements. Cycling causes a power plant's boiler, steam lines, turbine, and auxiliary components to go through unavoidably large thermal and pressure stresses.

D

Day-Ahead Load Shift (DALS) Program

A DR capacity grid service capable of providing a static period pricing rate delivered to commercial customers six hours before the starting day of an event for on-peak, off-peak, and mid-day times. Through the price differential, customers are encouraged to shift their energy usage from the peak time to the middle of the day when solar PV is at its peak, or at night when demand is low

Daytime Minimum Load (DML)

The absolute minimum demand for electricity between 9 AM and 5 PM on one or more circuits each day.

Demand

The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in kilowatts (kW = 1 kilowatt = 1,000 watts), while energy use is usually measured in kilowatt-hours (kWh = kilowatts x hours of use = kilowatt-hours). Load is considered synonymous with demand. (See also Load, Electric on page A-20.)

Demand Charge

A customer charge intended to allocate fixed grid costs to customers based on each customer's consumption demand.

Demand Response (DR)

Changes in electric usage by end-use customers from their normal consumption patterns in response to incentives caused by changes in the state of the electric grid or changes in the price of electricity. The underlying objective of demand response is to actively engage customers in modifying the demand for electricity to address system needs, in lieu of relying on utility-scale generating assets to address system needs.

Ancillary Services: Demand response programs and responses that provide the ancillary services required to continually meet demand or to maintain system stability.

Load Control: Includes direct control by the utility or other authorized third party of customer end-uses such as air conditioners, lighting, water heaters, distributed storage, electric vehicles, and motors. Load control can entail partial load reductions or complete load interruptions as well as load increase as needed. Customers usually receive financial consideration for participation in load control programs.

Price Response: Refers to programs that provide pricing incentives to encourage customers to change their electricity usage profile. Price response programs include real-time pricing, day-ahead load shift, time-of-use (TOU), and critical peak pricing (CPP) incentives.

Demand-Side Management (DSM)

The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility or third party-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Department of Business, Economic Development, & Tourism (DBEDT)

Hawai‘i’s resource center for economic and statistical data, business development opportunities, energy and conservation information, and foreign trade advantages. DBEDT’s mission is to achieve a Hawai‘i economy that embraces innovation and is globally competitive, dynamic and productive, providing opportunities for all Hawai‘i’s citizens. Through DBEDT’s attached agencies, it also fosters planned community development, creates affordable workforce housing units in high-quality living environments, and promotes innovation sector job growth.

Department of Land and Natural Resources (DLNR)

A department within the Hawai‘i state government responsible for managing Hawai‘i’s unique natural and cultural resources. Also oversees state-owned and state conservation lands.

DG 2.0

A generic term used in the 2014 PSIPs to describe revised tariff structures governing export and non-export models, based on fair allocation of costs among distributed generation (DG) customers and traditional retail customers, and fair compensation of DG customers for energy provided to the grid.

DG-PV (Distributed Generation-Photovoltaics)

An initialism describing the entirety of distributed photovoltaic generation (sometimes referred to as rooftop solar) on the power grid.

Direct Current (DC)

An electric current whose flow of electric charge remains constant. Certain renewable power generators (such as solar PV) deliver DC electricity, which must be converted to AC electricity using an inverter, for use in the power system.

Direct Load Control (DLC)

This Demand-Side Management category represents the consumer load that can be interrupted by direct control of the utility system operator. For example, the utility may install a device such as a radio-controlled device on a customer's air conditioning equipment or water heater. During periods of system need, the utility will send a radio signal to the appliance with this device and control the appliance for a set period of time.

Direct Transfer Trip (DTT)

A protection mechanism that originates from station relays in response to a specific system event. Remote events, such as generator trips, can cause load shed through DTT.

Dispatchable Generation

A generation source that is controlled by a system operator or dispatcher who can increase or decrease the amount of power from that source as the system requirements change.

Distributed Energy Resources (DER)

Non-centralized generating and storage systems that are co-located with energy load. Also known as Distributed Generation (see Distributed Generation two entries below).

Distributed Energy Storage System (DESS)

Energy storage systems sited on the distribution circuit, including substation-sited and customer-sited storage.

Distributed Generation (DG)

A term referring to a small generator that is sited at or near load, and that is attached to the distribution grid. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics. Also known as a Distributed Energy Resource (see Distributed Energy Resources two entries above).

Distribution Circuit Monitoring Program (DCMP)

A document filed by the Companies on June 27, 2014, outlining three broad goals. First, to measure circuit parameters to determine the extent to which distributed solar photovoltaic (PV) generation is causing safety, reliability, or power quality issues. Second, to ensure that distributed generation circuit voltages are within tariff and applicable standards. Third, to increase the Companies' knowledge of what is occurring on high PV penetration circuits to determine boundaries and thresholds and further future renewable DG integration work.

Distribution Circuit

The physical elements of the grid involved in carrying electricity from the transmission system to end users.

Distribution Transformer

A transformer used to step down voltage from the distribution circuit to levels appropriate for customer use.

Disturbance Ride-Through

The capability of resources to remain connected to the grid during transient off-normal voltage and frequency conditions that occur for typical system disturbances.

Droop and Droop Response

The amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop. Droop response is the time it takes for online generators to pick up load following a contingency event. Electrical systems with faster droop response times can better withstand contingency events.

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page A-5.

E

Economic Dispatch

The allocation of load to online dispatchable generating units based on their costs, to effect the most economical production of electricity for customers.

Electric Power Research Institute (EPRI)

A nonprofit research and development organization that conducts research, development and demonstration relating to the generation, delivery, and use of electricity.

Electric Vehicle (EV)

A vehicle that uses one or more electric motors or traction motors for propulsion.

Electricity

The set of physical phenomena associated with the presence and flow of electric charge.

Emissions

An electric power plant that combusts fuels releases pollutants to the atmosphere (for example, emissions of sulfur dioxide) during normal operation. These pollutants may be classified as primary (emitted directly from the plant) or secondary (formed in the atmosphere from primary pollutants). The pollutants emitted will vary based on the type of fuel used.

Energy

The ability to produce work, heat, light, or other forms of energy. It is measured in watt-hours. Energy can be computed as capacity or demand (measured in watts), multiplied by time (measured in hours). For example, a 1 megawatt (one million watts) power plant running at full output for 1 hour will produce 1 megawatt-hour (one million watt-hours or 1,000 kilowatt-hours) of electrical energy.

Energy Efficiency DSM

Programs designed to encourage the reduction of energy used by end-use devices and systems. Savings are generally achieved by substituting more technologically advanced equipment to produce the same level of energy services (for example, lighting, water heating, motor drive) with less electricity. Examples include programs that promote the adoption of high-efficiency appliances and lighting retrofit programs through the offering of incentives or direct install services.

Energy Efficiency Portfolio Standard (EEPS)

A goal for reducing the demand for electricity in Hawai‘i through the use of energy efficiency and displacement or offset technologies set by state law. The EEPS went into effect in January 2015. Until that time, energy savings from these technologies were included in the calculations for Hawai‘i's RPS. The EEPS for Hawai‘i provides for a total energy efficiency target of 4,300,000 megawatt-hours per year by the year 2030. To the extent that this target is achieved, this quantity of electric energy will not be served by Hawai‘i's electric utilities. Therefore, the projected amount of energy reductions due to energy efficiency are removed from the system energy requirement forecasts.

Energy Information Administration (EIA)

A principal agency of the United States Federal Statistical System (within the U.S. Department of Energy) responsible for collecting, analyzing, and disseminating energy information. One of its major roles is to provide publically available fuel price projections for the power generation industry.

Energy Management System (EMS)

A centralized system of computer-aided tools used to monitor, control, and optimize the performance of the utility power system and interconnected resources.

Energy Storage

A system or a device capable of storing electrical energy. Three major types of energy storage are relevant for consideration in Hawai‘i.

Battery: An energy storage device composed of one or more electrolyte cells that stores chemical energy. A large-scale battery can provide a number of ancillary services, including frequency regulation, voltage support (dynamic reactive power supply), load following, and black start as well as providing energy services such as peak shaving, valley filling, and potentially energy arbitrage. Also referred to as a Battery Energy Storage System (BESS).

Flywheel: A cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and potentially spinning reserve.

Pumped Storage Hydroelectric: Pumped storage hydro facilities typically use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water uphill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following and black start as well as energy services such as peak shaving and energy arbitrage.

Expense

An outflow of cash or other consideration (for example, incurring a commercial credit obligation) from a utility to another person or company in return for products or services (fuel expense, operating expense, maintenance expense, sales expense, customer service expense, interest expense.). An expense might also be a non-cash accounting entry where an asset (created as a result of a Capital Expenditure) is used up (for example, depreciation expense) or a liability is incurred.

F

Fast Frequency Response (FFR1 and FFR2)

FFR reduces the rate of change of frequency (RoCoF) with a response proportional to the generation contingency, and quickly restores the balance between supply and demand following a loss of load reducing operational down reserves from synchronous generation. FFR1 reduces the Rate of Change of Frequency (RoCoF) caused by the loss of generation; FFR1 is a proportional response. FFR2 reduces the RoCoF caused by the loss of generation. FFR2 is considered fixed because, once committed, it cannot be altered; however, the amount available can be variable because the FFR2 capacity depends on customer load.

Fast Frequency Response (FFR) Program

A DR fast frequency response grid service capable of responding to a contingency event (the maximum FFR requirement depending on the total available MW). A customer who enrolls in this DR program must be able to meet the requirements specified by FFR1 or FFR2.

Federal Energy Regulatory Commission (FERC)

FERC is the United States federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce, regulates the transportation of oil by pipeline in interstate commerce, and licenses non-federal hydropower projects. FERC also reviews proposals to build interstate natural gas pipelines, natural gas storage projects, and liquefied natural gas (LNG) terminals.

Feeder

A circuit carrying power from a major conductor to a one or more distribution circuits.

Firm Capacity

See Capacity, Generating on page A-4.

Feed-In Tariff (FIT) Program

A FIT program specific to the Hawaiian Electric Companies, under guidelines issued by the Hawai‘i Public Utilities Commission, which allows customers to sell the renewable electric energy produced by a qualifying system to the electric utility.

Feed-In Tariff (FIT)

The generic term for the rate at which exported DG-PV is compensated by the utility.

Five-Five-Five (5-5-5)

A grant initiative started in 2012 by the Joint Center for Energy Storage Research (JCESR) whose goal is to provide a grid-enabled battery that is capable of providing five times the energy density at one-fifth the cost of commercial batteries within five years.

Floating Storage and Regasification Unit (FSRU)

An FSRU is an LNG vessel, either near-shore or off-shore, that enables LNG to be transferred from an LNG transit carrier ship. The transferred LNG can then be stored and regasified before ultimately being distributed onshore as natural gas.

Flywheel

See Energy Storage on page A-12.

Forced Outage

See Outage on page A-26.

Forced Outage Rate

See Outage on page A-26.

Fossil Fuel

Any naturally occurring fuel formed from the decomposition of buried organic matter, essentially coal, petroleum (oil), and natural gas. Fossil fuels take millions of years to form, and thus are non-renewable resources. Because of their high percentages of carbon, burning fossil fuels produces about twice as much carbon dioxide (a greenhouse gas) as can be absorbed by natural processes.

Frequency

The number of cycles per second through which an alternating current passes. Frequency has been generally standardized in the United States electric utility industry at 60 cycles per second (60 Hz). The power system operator strives to maintain the system frequency as close as possible to 60 Hz at all times by varying the output of dispatchable generators, typically through automatic means. In general, if demand exceeds supply, the frequency will drop below 60 Hz; if supply exceeds demand, the frequency will rise above 60 Hz. If the system frequency drops to an unacceptable level (under-frequency), or rises to an unacceptable level (over-frequency), a system failure can occur. Accordingly, system frequency is an important indicator of the power system's condition at any given point in time.

Frequency Regulation

The effort to keep an alternating current at a consistent 60 Hz per second (or other fixed standard).

Full-Forced Outage

See Outage on page A-26.

G

Gas Turbine World

Gas Turbine World is a privately-published, bi-monthly journal for gas turbine buyers and users, and is designed to address their practical information needs with technical depth and real-world context. Gas Turbine World annually publishes its industry-benchmark GTW Handbook and its new production year GTW Performance Specs.

Generating Capacity

See Capacity, Generating on page A-4.

Generation (Electricity)

The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).

Nameplate Generation (Gross Generation): The electrical output at the terminals of the generator, usually expressed in megawatts (MW).

Net Generation: Gross generation minus station service or unit service power requirements, usually expressed in megawatts (MW). The energy required for pumping at a pumped storage plant is regarded as plant use and must be deducted from the gross generation.

Generator (Electric)

A machine that transforms mechanical, chemical, or thermal energy into electric energy. Includes wind generators, solar PV generators, and other systems that convert energy of one form into electric energy. (See also Capacity, Generating on page A-4.)

Geographic Information System (GIS)

A computer system designed to capture, store, manipulate, analyze, manage, and present all types of geographical data.

Gigawatt (GW)

A unit of power, capacity, or demand equal to one billion watts, one million kilowatts, or one thousand megawatts.

Gigawatt-Hour (GWh)

A unit of electric energy equal to one billion watt-hours, one million kilowatt-hours, or one thousand megawatt-hours.

Greenhouse Gases (GHG)

Any gas whose absorption of solar radiation is responsible for the greenhouse effect, including carbon dioxide, methane, ozone, and the fluorocarbons.

Grid (Electric)

An interconnected network of electric transmission lines and related facilities.

Grid Export

The total amount of DG-PV generation exported to the grid. Grid export through both the Customer Grid Supply or Customer Self Supply program is compensated at the same amount as grid-scale PV levelized cost of energy.

Grid-Scale Generation

A term coined for this PSIP that describes the same type of facility as utility-scale generation, however, makes clearer that such generation is not necessarily utility owned, but rather is owner agnostic. (See also Utility-Scale Generation on page A-37.)

Gross Generation

See Generation (Electricity) on page A-15.

H

Hawaiʻi Public Utilities Commission (PUC or Commission)

A state agency that regulates all franchised or certificated public service companies operating in Hawaiʻi. The Commission prescribes rates, tariffs, charges and fees; determines the allowable rate of earnings in establishing rates; issues guidelines concerning the general management of franchised or certificated utility businesses; and acts on requests for the acquisition, sale, disposition or other exchange of utility properties, including mergers and consolidations.

Hawaiʻi Revised Statute (HRS)

The codified laws of the State of Hawaiʻi. The entire body of state laws is referred to the Hawaiʻi Revised Statutes; the abbreviation HRS is normally used when citing a particular law.

Heat Rate

A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Heat Recovery Steam Generator (HRSG)

An energy recovery heat exchanger that recovers heat from a hot exhaust gas stream, and produces steam that can be used in a process (cogeneration) or used to drive a steam turbine in a combined-cycle plant.

I

IHS Energy

IHS Energy provides information, analytics, and insight about world energy markets. They publish and continually update energy-related forecasts and outlooks, analytical platforms and datasets, and an exploration and production database. IHS Energy provides detailed data that, among many other benefits, enables better capital investments as well as capital and operating costs analysis and optimization.

Impacts

The positive or negative consequences of an activity. For example, there may be negative consequences associated with the operation of power plants from the emission discharge or release of a material to the environment (for example, health effects). There may also be positive consequences resulting from the construction and siting of power plants which could affect society and culture.

Impedance

A measure of the opposition to the flow of power in an AC circuit.

Independent Power Producer (IPP)

Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, co-generators (or combined heat and power generators) and small power producers (including net metered and feed-in tariff systems) and all other non-utility electricity producers, such as exempt wholesale generators, who sell electricity or exchange electricity with the utility. IPPs are sometimes referred to as non-utility generators.

Independent System Operator (ISO)

An ISO is an independent, nonprofit organization comprised of member utilities. In general, an ISO oversees the operation of a bulk electric power system, its transmission lines, and the electricity market generated and transmitted by its member utilities. The goal of an ISO is to operate the grid reliably and efficiently, provide fair and open transmission access, promote environmental stewardship, and facilitate effective markets and promote infrastructure development.

Industrial Fuel Oil (IFO)

A fuel oil that contains less than 20,000 parts per million of sulfur, or 2% sulfur content. Also referred to as medium sulfur fuel oil (MSFO).

Inertia

Inertia is the response of generators from the kinetic energy in the rotating masses that remain online as frequency starts to drop following a contingency event. Inertia provides ride-through of momentary system disruptions to avoid a system contingency. Inertia reduces the rate of change of frequency (RoCoF), allowing slower governor actions to catch up and contribute to frequency stabilization. Electrical systems with high inertia are more robust and can better withstand contingency events.

Installed Capacity

See Capacity, Generating on page A-4.

Integrated Demand Response Portfolio Plan (IDRPP)

A comprehensive demand response portfolio proposal filed by the Companies with the Hawaiʻi Public Utilities Commission on July 28, 2014. We also filed an IDRPP Update on March 31, 2015; a supplemental report on November 6, 2015; and a revised supplemental report on Nov. 20, 2015.

Integrated Resource Plan (IRP)

The plan by which electric utilities identify the resources or the mix of resources for meeting near- and long-term consumer energy needs. An IRP conveys the results from a planning, analysis, and decision-making process that examines and determines how a utility will meet future demands. Developed in the 1980s, the IRP process integrates efficiency and load management programs, considered on par with supply resources; broadly framed societal concerns, considered in addition to direct dollar costs to the utility and its customers; and public participation into the utility planning process.

Interconnection Charge

A one-off charge to DG customers reflecting costs of studies and any potential upgrades (such as transformer upgrades) associated with distributed generation.

Intermediate Capacity

See Capacity, Generating on page A-4.

Intermittent Renewable Energy

See Variable Renewable Energy on page A-38.

Internal Combustion Engines (ICE)

A heat engine that combines fuel with an oxidizer (usually air) in a combustion chamber that creates pressure and mechanical force to generate electricity.

Inverter

A device that converts direct current (DC) electricity to alternating current (AC) either for stand-alone systems or to supply power to an electricity grid. An appropriately designed inverter can provide dynamic reactive power as well as real power and disturbance ride-through capability. A solar PV system uses inverters to convert DC electricity to AC electricity for use in the grid, or directly by a customer.

Islanding

A condition in which a circuit remains powered by non-utility generation (that is, distributed generation resources) even when the circuit has been disconnected from the wider utility power network.

K

Kilowatt (kW)

A unit of power, capacity, or demand equal to one thousand watts. The demand for an individual electric customer, or the capacity of a distributed generator, is sometimes expressed in kilowatts. The standard billing unit for electric tariffs with a demand charge component is the kilowatt.

Kilowatt-Hour (kWh)

A unit of electric energy equal to one thousand watt-hours. The standard billing unit for electric energy sold to retail consumers is the kilowatt-hour.

L

Levelized Cost of Energy (LCOE)

The price per kilowatt-hour for an energy project to break even; it does not include risk or return on investment.

Life-Cycle Costs

The total cost impact over the life of a program or the life of an asset. Life-cycle costs include Capital Expenditures, operation, maintenance and administrative expenses, and the costs of decommissioning.

Liquefied Natural Gas (LNG)

Natural gas that has been cooled until it turns liquid to make storage and transport easier. LNG must be regasified before it can be burned as fuel.

Load, Electric

The term load is considered synonymous with demand. Load may also be defined as an end-use device or an end-use customer that consumes power. Using this definition of load, demand is the measure of power that a load receives or requires.

Baseload: The constant generation of electric power load to meet demand.

Connected Load: The sum of the capacities or ratings of the electric power consuming apparatus connected to a supplying system, or any part of the system under consideration.

Load Balancing

The efforts of the system operator to ensure that the load is equal to the generation. During normal operating conditions the system operator utilizes load following and frequency regulation for load balancing.

Load Control Program

A program in which the utility company offers some form of compensation (for example, a bill credit) in return for having permission to remotely control a customer's energy use (such as controlling an air conditioner or water heater) for defined periods of time. Also references as Demand Response (DR).

Load Forecast

An estimate of the level of future energy needs of customers in an electric system. Bottom-up forecasting uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down forecasting uses utility meters at generation and transmission sites to develop aggregate control area loads; useful in determining reliability planning requirements, especially where retail choice programs are not in effect.

Load Management DSM

Electric utility or third party marketing programs designed to encourage the utility's customers to adjust the timing of their energy consumption. By coordinating the timing of its customers' consumption, the utility can achieve a variety of goals, including reducing the utility's peak system load, increasing the utility's minimum system load, and meeting unusual, transient, or critical system operating conditions.

Load Profile

Measurements of a customer's electricity usage over a period of time which shows how much and when a customer uses electricity. Load profiles can be used by suppliers and transmission system operators to forecast electricity supply requirements and to determine the cost of serving a customer.

Load Shedding

A purposeful, immediate response to curtail electric service. Load shedding is typically used to curtail large blocks of customer load (for example, particular distribution feeders) during an under frequency event (when frequency drops below a certain level) when demand for electricity exceeds supply (for example, during the sudden loss of a generating unit).

Load Tap Changer (LTC)

A substation controller used to regulate the voltage output of a transformer.

Loss-of-Load Probability (LOLP)

The probability that a generation shortfall (loss of load) would occur. This probability can be used as a consideration in generation adequacy requirements. The generation adequacy planning criteria for O‘ahu requires the LOLP not to exceed one outage day every 4½ years. The other four islands we serve do not define a minimum LOLP, but rather plan for generation adequacy of supply through reserve margin calculations.

Low Sulfur Diesel (LSD)

A diesel fuel that contains a maximum of 500 parts per million of sulfur.

Low Sulfur Fuel Oil (LSFO)

A fuel oil that contains less than 500 parts per million of sulfur; about 0.5% sulfur content.

Low Sulfur Industrial Fuel Oil (LSIFO)

A fuel oil that contains up to 7,500 parts per million of sulfur; about 0.75% sulfur content. LSIFO is used if a fuel with lower sulfur content than medium sulfur fuel oil is needed.

Low Voltages

Voltages above 0.9 per unit that are of concern because these voltages can become an under voltage violation in the future.

M

Maintenance Outage

See Outage on page A-26.

MBtu

A thousand Btu. (See also British Thermal Unit on page A-3.)

Medium Sulfur Fuel Oil (MSFO)

A fuel oil that contains between 1,000 and 5,000 parts per million of sulfur; between 1% and 3.5% sulfur content.

Megawatt (MW)

A unit of power, capacity, or demand equal to one million watts or one thousand kilowatts. Generating capacities of power plants and system demand are typically expressed in megawatts.

Megawatt-Hour (MWh)

A unit of electric energy equal to one million watt-hours or one thousand kilowatt-hours. The energy output of generators or the amount of energy purchased from Independent Power Producers is oftentimes specified in megawatt-hours.

Mercury and Air Toxics Standard (MATS)

A federal standard that requires coal- and oil-fired power plants to limit the emissions of toxic air pollutants: particular matter (such as arsenic), heavy metals (such as mercury) and acid gases (such as carbon dioxide).

Minimum Load (ML) Program

A DR capacity grid service that provides incentives to customers to shift their usage to the middle of the day to increase demand during that period when DG-PV generation is high. This program was not included in any DR portfolio analysis because load shifting programs such as time-of-use (TOU), day-ahead load shift (DALS), and real-time pricing (RTP) were already fulfilling this load flattening benefits.

MMBtu

One million Btu. (See also British Thermal Unit on page A-3.)

Must-Run Unit

A generation facility that must run continually due to operational constraints or system requirements to maintain system reliability; typically a large thermal power plant.

N

N-1 Contingency

The unexpected failure or outage of a single system component (such as a generator, transmission line, circuit breaker, switch, or other electrical element); and can include multiple electrical elements if they are linked so that failures occur simultaneously at the loss of the single component. Also known as an N-1 condition.

Nameplate Generation

See Generation (Electricity) on page A-15.

National Ambient Air Quality Standards (NAAQS)

A Federal standard, set by the Environmental Protection Agency (EPA), to limit the emission of six "criteria" pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, particulate matter, and sulfur dioxide (SO_2). These regulations apply to all fuel-fired power plants.

National Pollutant Discharge Elimination System (NPDES)

NPDES permits, administers, and enforces a program that regulates pollutants discharged into water sources.

National Renewable Energy Laboratory (NREL)

The Federal laboratory dedicated to researching, developing, commercializing, and using renewable energy and energy efficiency technologies. NREL creates a wealth of well researched studies that utilities across the country rely on for planning to integrate renewable generation.

Net Capacity

See Capacity, Generating on page A-4.

Net Energy Metering (NEM)

A financial arrangement between a customer with a renewable distributed generator and the utility, where the customer only pays for the net amount of electricity taken from the grid, regardless of the time periods when the customer imported from or exported to the grid. Under a NEM arrangement, the customer is allowed to remain connected to the power grid, so that the customer can take advantage of the grid's reliability infrastructure (such as ancillary services provided by generators, energy storage devices, and demand response programs), use the grid as a "bank" for power generated by the customer in excess of the customer's needs, and use the grid as a backup resource for times when the power generated by the customer is less than the customer's needs.

Net Generation

See Generation (Electricity) on page A-15.

New Source Review (NSR)

A permitting process created by Congress in 1977 as an amendment to the Clean Air Act requiring pre-construction review for environmental controls for the construction of new facilities or modifications to existing facilities (not routine scheduled maintenance) that would significantly increase a regulated pollutant. NSR was designed to eventually force the modernization of existing generation assets to comply with air emission regulations.

New Source Performance Standards (NSPS)

Created as part of the Clean Air Act in 1970 to establish limits for certain air pollution emissions and water pollution discharges for how much certain categories of new facilities or modified existing facilities (such as boilers) can emit.

Nitrogen Oxide (NOx)

A pollutant and strong greenhouse gas emitted by combusting fuels.

Nominal Dollars

At its most basic, nominal dollars are based on a measure of money over a period of time that *has not been* adjusted for inflation. Nominal value represents a cost usually in the current year. As such, nominal dollars can also be referred to as current dollars; in other words, what it costs to buy something today. Nominal dollars are often contrasted with real dollars.

Non-Spin Auto Response (NSAR) Program

A 10-minute DR resource capable of replacing other resources that are used for Replacement Reserves (RR). Replacement Reserves may be used for restoring regulation or contingency reserves. A customer enrolled in this NSAR program would have 10 minutes to respond and reduce their enrolled load resource.

Non-Transmission Alternative (NTA)

Programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system.

North American Electric Reliability Corporation (NERC)

An international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America.

O

Ocean Thermal Energy Conversion (OTEC)

A process that can produce electricity by using the temperature difference between deep cold ocean water and warm tropical surface waters.

Off-Peak Energy

Electric energy supplied during periods of relatively low system demands as specified by the supplier. In general, this term is associated with electric water heating and pertains to the use of electricity during that period when the overall demand for electricity from our system is below normal.

Once-Through Steam Generator (OTSG)

A specialized type of HRSG without boiler drums that enables the inlet feedwater to follow a continuous path (without segmented sections for economizers, evaporators, and superheaters) allowing it to grow or contract based on the heat load being received from the gas turbine exhaust. OTSGs can be run dry, meaning the hot exhaust gases can pass over the tubes with no water flowing inside the tubes.

On-Peak Energy

Electric energy supplied during periods of relatively high system demand as specified by the supplier.

Operation and Maintenance (O&M) Expense

The recurring costs of operating, supporting, and maintaining authorized programs, including costs for labor, fuel, materials, and supplies, and other current expenses.

Operating Reliability

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components. Operating reliability is synonymous with system security. (See also System Security on page A-35.)

Operating Reserves

That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve. (See also Reserve on page A-32.)

Outage

The period during which a generating unit, transmission line, or other facility is out of service. The following are types of outages or outage-related terms.

Forced Outage: The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate: The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Maintenance Outage: The removal of equipment from service availability to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Partial Outage: The outage of a unit or plant auxiliary equipment that reduces the capability of the unit or plant without causing a complete shutdown. It may also include the outage of boilers in common header installations.

Planned (or Scheduled) Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

P

Partial Outage
See Outage on page A-26.

Particulate Matter (PM)
A complex mixture of extremely small particles and liquid droplets made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

Peak Demand
The maximum amount of power necessary to supply customers; in other words, the highest electric requirement occurring in a given period (for example, an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. From a customer's perspective, peak demand is the maximum power used during a specific period of time.

Peaker
A generation resource that generally runs to meet peak demand, usually during the late afternoon and early evening when the demand for electricity during the day is highest. It is also referred to as a peaker plant or a peaking power plant. These resources are often used for supplemental reserves.

Peaking Capacity
See Capacity, Generating on page A-4.

Photovoltaic (PV)
Electricity from solar radiation typically produced with photovoltaic cells (also called solar cells): semiconductors that absorb photons and then emit electrons.

Photovoltaic Curtailment (PVC) Program
A DR capacity grid service capable of curtailing a customer's PV generation when minimum must-run generators are within a specified threshold limit that requires more system load to prevent the sudden loss of an online generator. PVC is expected to offer circuit-level value in helping to address back-feeding risks as well as power quality and voltage issues. The Demand Response team will collaborate on the development of DER

Phase 2 program design to help identify opportunities to incorporate specific PVC options.

Planned Outage

See Outage on page A-26.

Planning Reserve

See Reserve on page A-32.

Power

The rate at which energy is supplied to a load (consumed), usually measured in watts (W), kilowatts (kW), megawatts (MW), gigawatts (GW), and terawatts (TW).

Power Factor

A dimensionless quantity that measures the extent to which the current and voltage sine waves in an AC power system are synchronized. If the voltage and current sine waves perfectly match, the power factor is 1.0. Power factors not equal to 1.0 result in dissipation of electric energy into losses.

Power Purchase Agreement (PPA)

A contract for an electric utility to purchase energy and or capacity from a commercial source (for example, an Independent Power Producer) at a predetermined price or based on pre-determined pricing formulas.

Present Value

The value of an asset, taking into account the time value of money—a future dollar is worth less today. Present value dollars are expressed in a constant year dollars (usually the current year). Future dollars are converted to present dollars using a discount rate. For example, if someone borrows money from you today and agrees to pay you back $1.00 in one year at a discount rate of 10%, you would be only be willing to loan the other person $0.90 today. Utility planners use present value as a way to directly compare the economic value of multi-year plans with different future expenditure profiles. Net present value (NPV) is the difference between the present value of all future benefits, less the present value of all future costs.

Primary Frequency Response (PFR)

Primary frequency response are reserves are the reserve capacity from online synchronous generation that provides both regulating reserves and contingency reserves. PFR is available to handle the sudden loss of a generator or major transmission line with a response proportional to the changes in frequency. In general, the largest online unit tends to determine the amount of PFR available to the system following a contingency event. If this largest unit trips offline, then the generators already online (and "spinning") can quickly pick up load within a defined time period to keep the system running.

Public Benefits Fee Administrator (PBFA)

A third-party agent that handles energy efficiency rebates and incentives within the service territories of the Hawaiian Electric Companies.

Pumped Storage Hydroelectric

See Energy Storage on page A-12.

Q

Qualitative

Consideration of externalities which assigns relative values or rankings to the costs and benefits. This approach allows expert assessments to be derived when actual data from conclusive scientific investigation of impacts are not available.

Quantitative

Consideration of externalities which provides value based on available information on impacts. This approach allows for the quantification of impacts without assigning a monetary value to those impacts (for example, tons of crop loss).

R

Ramp Rate

A measure of the speed at which a generating unit can increase or decrease output, generally specified as MW per minute.

Rate Base

The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the book value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes net cost of plant in service, working cash, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment (such as capacitors) and directly influences electric system voltage.

Real Dollars

At its most basic, real dollars are a measure of money over a period of time that *has been* adjusted for inflation. Real dollars represents the true cost of goods and services sold because the effects of inflation are stripped out of the cost. Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars; in other words, if the price of something goes up over time at the same rate as inflation, the cost is the same in real dollars. Real dollars are often contrasted with nominal dollars.

Real-Time Pricing (RTP) Program

A DR capacity grid service capable of providing hourly retail rate prices to customers up to six hours before the event day starts. Retail rates are based on weather, system resource availability, and forecasted load profile. The most operationally and cost-efficient way to deliver Residential RTP programs is with an AMI infrastructure in place.

Reciprocating Internal Combustion Engines (RICE)

A reciprocating internal combustion engine uses the reciprocating movement of pistons to create pressure that is converted into electricity.

Regulation Reserves (RR) Program

A DR grid service capable of providing up and down reserves to balance system variability. A customer who enrolls in this program must be able to provide a load resource that could initiate a response within two seconds. The Companies examined RegDown as an additional program option, and while there are sufficient resources projected of being able to deliver such a service, the modeling efforts undertaken did not demonstrate a significant value of this service based on the current resource mix expected to deliver that RegDown service.

Regulating Reserves (RegUp & RegDown)

The service used to maintain system frequency in response to supply and demand imbalances over short time frames, typically on the order of one to several seconds. RegUp and RegDown resources adjust their generation or load levels in response to automatic generation control (AGC) signals provided by the system operator.

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, adequacy of supply and system security. (See also System Reliability on page A-34.)

Renewable Energy Resources

Energy resources that are naturally replenished, but limited in their constant availability (or flow). They are virtually inexhaustible but are limited in the amount of energy that is available over a given period of time. The amount of some renewable resources (such as geothermal and biomass) might be limited over the short term as stocks are depleted by use, but on a time scale of decades or perhaps centuries, they can likely be replenished.

Renewable energy resources currently in widespread use include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. Other renewables resources still under development include ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Unlike fossil fuel generation plants (which can be sited where most convenient because the fuel is transported to the plant), most renewable energy generation plants must be sited where the energy is available; that is, a wind farm must be sited where a sufficient and relatively constant supply of wind is available. In other words, fossil fuels can be brought to their generation plants whereas most renewable energy generating plants must be brought to the renewable energy source. Some renewable resources are exceptions; their fuels (such as biomass and biofuels), like fossil generation, can be brought to the generation plant.

Renewable Portfolio Standards (RPS)

A goal for the percentage of electricity sales in Hawaiʻi to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies were part of the RPS until January 2015, after which they were counted toward the new Energy Efficiency Portfolio Standard (EEPS).

The current RPS statute calls for 10% of net electricity sales by December 31, 2010; 15% of net electricity sales by December 31, 2015; 25% of net electricity sales by December 31, 2020; and 40% of net electricity sales by December 31, 2030; 70% of net electricity sales by December 31, 2040; and 100% of net electricity sales by December 31, 2045.

Replacement Reserves (RR)

Off-line, quick-start resources that can be used as a replacement reserve provided they can be started and synchronized to the grid by a 10-minute or 30-minute timeframe depending upon system needs. These resources may be used for restoring load, regulation or supporting and replacing contingency reserves.

Reserve

There are two types of reserves.

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. (See also Operating Reserves on page A-26.)

Planning Reserve: The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Reserve Margin (Planning)

The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in a planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy of supply (AOS).

Resiliency

The ability to quickly locate faults and automatically restore service after a fault, using FLISR (Fault Location, Isolation, and Service Restoration).

Retail Rate

The rate at which specific classes of customers compensate the utility for grid electricity.

Reverse Flow

The flow of electricity from the customer site onto the distribution circuit or from the distribution circuit through the substation to higher voltage lines. Also called backfeed.

RSMeans Construction Index

RSMeans is the world's leading provider of construction cost data, software, and services for all phases of the construction lifecycle, providing accurate and up-to-date cost information to help project and control the cost of both new building construction and renovation projects. RSMeans annually updates and publishes a collection of cost data books.

S

Scheduled Outage

See Outage on page A-26.

Service Charge

A fixed customer charge intended to allocate the cost of servicing the grid to all customers, regardless of capacity needs.

Simple-Cycle Combustion Turbine (SCCT)

A generating unit in which the combustion turbine operates in a stand-alone mode, without waste heat recovery.

Single-Train Combined Cycle (STCC)

See Combined Cycle on page A-5.

Smart Grid

A platform connecting grid hardware devices to smart grid applications, including Advanced Metering Infrastructure (AMI), Volt/VAR Optimization (VVO), Direct Load Control (DLC), and electric vehicle charging.

Special Use Permit

A permit required for the construction of solar and wind facilities on Agricultural rated B or C land that represents 10% of the entire parcel or 20 acres, whichever is less. Such a facility must also meet the criteria set forth in Act 55 (Session Laws of Hawaiʻi, 2014) pertaining to making the project site available for compatible agricultural uses at discounted rates, project decommissioning, and site restoration. All special use permit applications are review by one or more state agencies and are difficult to obtain.

Spinning Reserves

See Primary Frequency Response on page A-28.

Steam Turbine (ST)

A turbine that is powered by pressurized steam and provides rotary power for an electrical generator.

Stochastic Modeling

Modeling analysis using as input a random collection of variables that represent the uncertainties associated with those variables (as opposed to deterministic modeling that analyzes a single state). Stochastic modeling analyzes multiple states and the range of their uncertainty, then captures the probabilities of those uncertainties.

Sulfur Oxide (SO_x)

A precursor to sulfates and acidic depositions formed when fuel (oil or coal) containing sulfur is combusted. It is a regulated pollutant.

Substation

A small building or fenced in yard containing switches, transformers, and other equipment and structures for the purpose of stepping up or stepping down voltage, switching and monitoring transmission and distribution circuits, and other service functions. As electricity gets closer to where it is to be used, it goes through a substation where the voltage is lowered so it can be used by customers such as homes, schools, and factories.

Supervisory Control and Data Acquisition (SCADA)

A system used for monitoring and control of remote equipment using communications networks.

Supply-Side Management

Actions taken to ensure the generation, transmission, and distribution of energy are conducted efficiently. Supply-side generation includes generating plants that supply power into the electric grid.

Switching Station

An electrical substation, with a single voltage level, whose only functions are switching actions.

System

The utility power grid: a combination of generation, transmission, and distribution components.

System Average Interruption Duration Index (SAIDI)

The average outage duration for each customer served. SAIDI is a reliability indicator.

System Average Interruption Frequency Index (SAIFI)

The average number of interruptions that a utility customer would experience. SAIFI is a reliability indicator.

System Reliability

Broadly defined as the ability of the utility system to meet the demand of its customers while maintaining system stability. Reliability can be measured in terms of the number of hours that the system demand is met.

System Security

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. (See also Operating Reliability on page A-26.)

T

Tariff

A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Terawatt (TW)

A unit of power, capacity, or demand equal to one trillion watts, one billion kilowatts, one million megawatts, or one thousand gigawatts. The total power used by humans worldwide is commonly measured in terawatts.

Terawatt Hour (TWh)

A unit of electric energy equal to one trillion watt-hours, one billion kilowatt-hours, one million megawatt-hours, or one thousand gigawatt-hours.

Time-of-Use (TOU) Program

A DR capacity grid service capable of providing a static period pricing rate for on-peak, off-peak, and mid-day times to residential customers. Through a price differential, customers are encouraged to shift their energy usage from the peak to the middle of the day when solar PV is at its peak, or at night when demand is low. When the time-of-use (TOU) program ends, participants will be able to transition to the RTP program.

Time-of-Use (TOU) Rates

The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter).

Total Resource Cost (TRC)

A method for measuring the net costs of a conservation, load management, or fuel substitution program as a resource option, based on the total costs of the program, including both the participants' and the utility's costs.

Transformer

A device used to change voltage levels to facilitate the transfer of power from the generating plant to the customer. A step-up transformer increases the voltage (power) of electricity while a step-down transformer decreases it.

Transmission and Distribution (T&D)

Transmission lines are used for the bulk transfer of electric power across the power system, typically from generators to load centers. Distribution lines are used for transfer of electric power from the bulk power level to end-users and from distributed generators into the bulk power system. Hawaiian Electric standard transmission voltages are 138,000 volts; and 69,000 volts (for Maui Electric and Hawaiʻi Electric Light). Distribution voltage is 23,000 volts (Maui Electric) and 13,200 volts (all systems).

Two-Way Communications

The platform and capabilities that are required to allow bi-directional communication between the utility and elements of the grid (including customer-sited advanced inverters), and control over key functions of those elements. The platform must contain monitor and control functions, be TCP/IP addressable, be compliant with IEC 61850, and provide cyber security at the transport and application layers as well as user and device authentication.

U

Ultra-Low Sulfur Diesel (ULSD)

A diesel fuel that contains less 15 parts per million of sulfur.

Under Frequency Load Shedding (UFLS)

A system protection scheme used during transient adverse conditions to balance load and generation. The term essentially explains the process: when frequency drops below a certain point, this scheme sheds load to keep from completely losing the system.

Under Voltage Load Shedding (UVLS)

A system protection scheme used during low voltage conditions to avoid a voltage collapse.

United States Department of Defense (DOD)

An executive department of the U.S. government responsible for coordinating and supervising all agencies and functions of the Federal government that are concerned directly with national security and the armed forces.

United States Department of Energy (DOE)

An executive department of the U.S. government that is concerned with the United States' policies regarding energy, environmental, and nuclear challenges.

United States Energy Information Administration (EIA)

The principal agency responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy. The EIA conducts independent comprehensive data collection of energy sources, end uses, and energy flows; generates short- and long-term domestic and international energy projections; and performs informative energy analyses. EIA programs cover data on coal, petroleum, natural gas, electric, renewable, and nuclear energy.

United States Environmental Protection Agency (EPA)

An executive department of the U.S. government whose mission is to protect human health and the environment.

University of Hawai'i Economic Research Organization (UHERO)

The economic research organization at the University of Hawai'i, which is a source for information about the people, environment, and Hawai'i and the Asia-Pacific economies, including energy issues.

Utility-Scale Generation

The designation for any small- or large-scale generation facility, usually a variable renewable resource such as solar PV or wind. These facilities can be either owned by the utility, or owned by an Independent Power Producer (IPP) under a Power Purchase Agreement (PPA). While generally not defined by output, their generation capabilities can range from as small as 1 MW to much larger (such as 100 MW or more). (See also Grid-Scale Generation on page A-16.)

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched to operate below the available energy, it cannot be increased above what can be produced by the available resource energy. Variable energy can be coupled with storage, or the primary energy source can be stored for future use (such as with solar thermal storage, or when converted into electricity via storage technologies). Also referred to as intermittent and as-available renewable energy.

Voltage

Voltage is a measure of the electromotive force or electric pressure for moving electricity.

Voltage Regulation

The control of voltage to keep the value within a specified target or range.

W

Waste-to-Energy (WTE)

A process of generating electricity from the primary treatment (usually burning) of waste. WTE is a form of energy recovery.

Watt

The basic unit of measure of electric power, capacity, or demand from the International System of Units (SI); named after the Scottish engineer James Watt (1736–1819).

Wave and Tidal Power

A process that captures the power of waves and tides and converts it into electricity. While the arrival of waves at a power facility is somewhat predictable (mainly because waves travel across the ocean), tides are extremely predictable because they are driven by the gravitational pull of the moon and sun.

B. Party Commentary and Input

The Hawaiian Electric Companies have actively sought input from the Participants and Intervenors (collectively referred to as the "Parties") to the PSIP proceeding to assist us in updating, supplementing, and amending our initial 2014 PSIPs[1] as directed in Order No. 33320.[2] Our solicitations started with our *Proposed PSIP Revision Plan*[3] that presented a schedule of conferences for just this purpose and included a table itemizing the input we needed for our modeling analyses. Continuing with our *Power Supply Improvement Plan Update Interim Status Report*,[4] we made it clear that we were proactively soliciting input from the Parties, even inviting the Intervenors to our internal planning meetings and engaging in one-on-one dialogue with most of the Parties. We initially held a stakeholder conference, and proposed another, to engage in direct discourse with the Parties; and participated in two technical conferences held by the Commission to further engage the Parties.

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[1] Docket 2011-0206: *Hawaiian Electric Power Supply Improvement Plan*; Docket 2011-0092: *Maui Electric Power Supply Improvement Plan*; Docket 2012-0212: *Hawai'i Electric Light Power Supply Improvement Plan*; all instituted on August 26, 2014; and subsequent filing in Docket 2014-0183: *Hawaiian Electric Companies Power Supply Improvement Plan Errata*.

[2] Docket No. 2014-0183, Order No. 33320: *Admitting Intervenors and Participants, Identifying Observations and Concerns, Specifying Initial Statement of Issues, and Establishing Schedule of Proceedings*, issued November 4, 2015.

[3] Docket No. 2014-0183, *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, filed November 25, 2015.

[4] Docket No. 2014-0183, *Power Supply Improvement Plan Update Interim Status Report*, filed February 16, 2016.

After filing our *PSIP Update Report: April 2016*,[5] we continued to engage the Parties and solicit input through two more stakeholder conferences, more personal invitations for Intervenors to attend our internal planning meetings, numerous impromptu meetings, two technical conferences, four structured stakeholder meetings, and myriad email exchanges. We received commentary and input from the Parties and general public in response to Order No. 33740.[6] Except for certain confidential information covered by the Commission's protective order, we shared *all* information with the Parties through a web interface. We have considered *all* input and commentary, incorporating all relevant, credible, and timely input into the development of our updated PSIP. We remain open to and expect input from stakeholders in future planning cycles.

This appendix:

- Reviews the background of the PSIP docket.
- Highlights and explores relevant Party input and commentary, and their impact on our modeling analyses.
- Details the communication surrounding our three stakeholder conferences and the last two technical conferences as well as the four stakeholder meetings, providing an overview of the proceedings and the input received.
- Compiles the Party comments filed in response to Order No. 33320, and explains how we responded to it and included it in our analyses.
- Summarizes the Party and general public submissions in response to Order No. 33740, then compiles this input into topics and explains how we responded to it.
- Concludes by including the presentation slides from the stakeholder conferences.

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5 Docket No. 2014-0183, *Power Supply Improvement Plan Update Report: April 2016*, filed April 1, 2016.

6 Docket No. 2014-0183, Order No. 33740: *Inviting Comments on the HECO Companies' Power Supply Improvement Plan Update*, issued June 3, 2016.

THE UPDATED PSIP PROCEEDING

The updated PSIP proceeding has included:

- Six Commission Orders (together with a Protective Order and a Company Motion for Clarification).[7]
- Seven opportunities for comments and input from the Parties.
- Three sets of information request (IR) letters and responses.
- Four Commission technical conferences.
- Three Company stakeholder conferences.
- Four organized stakeholder meetings.
- Five Company PSIP report-related filings culminating in this *PSIP Update Report: December 2016*.

The overall PSIP proceeding began with Order No. 32257[8] that instituted Docket 2014-0183 to review the PSIPs that we were directed to file by August 28, 2014. The intent of this proceeding was to "review the HECO Companies' Power Supply Improvement Plans". The Order named the Consumer Advocate and our three operating utilities—Hawaiian Electric, Maui Electric, and Hawai'i Electric Light—as parties to the docket.

A little more than two weeks after we filed our 2014 PSIPs, the Commission issued Order No. 32294 inviting public comments on our plans. While not intending to limit comments, the Order did specifically request "commenters to address whether the plans provide clear, actionable strategies to:

- lower and stabilize customer bills;
- integrate a diverse portfolio of cost-effective renewable energy projects;
- operate each island grid reliably and cost-effectively with substantial quantities of variable renewable energy resources; and
- contain appropriate strategies and timely action plans, supported by well-reasoned and compelling analyses, to achieve these goals on each island."[9]

Figure B-1 on the following two pages depicts a visual representation of the milestones and deadlines that comprise this PSIP update proceeding.

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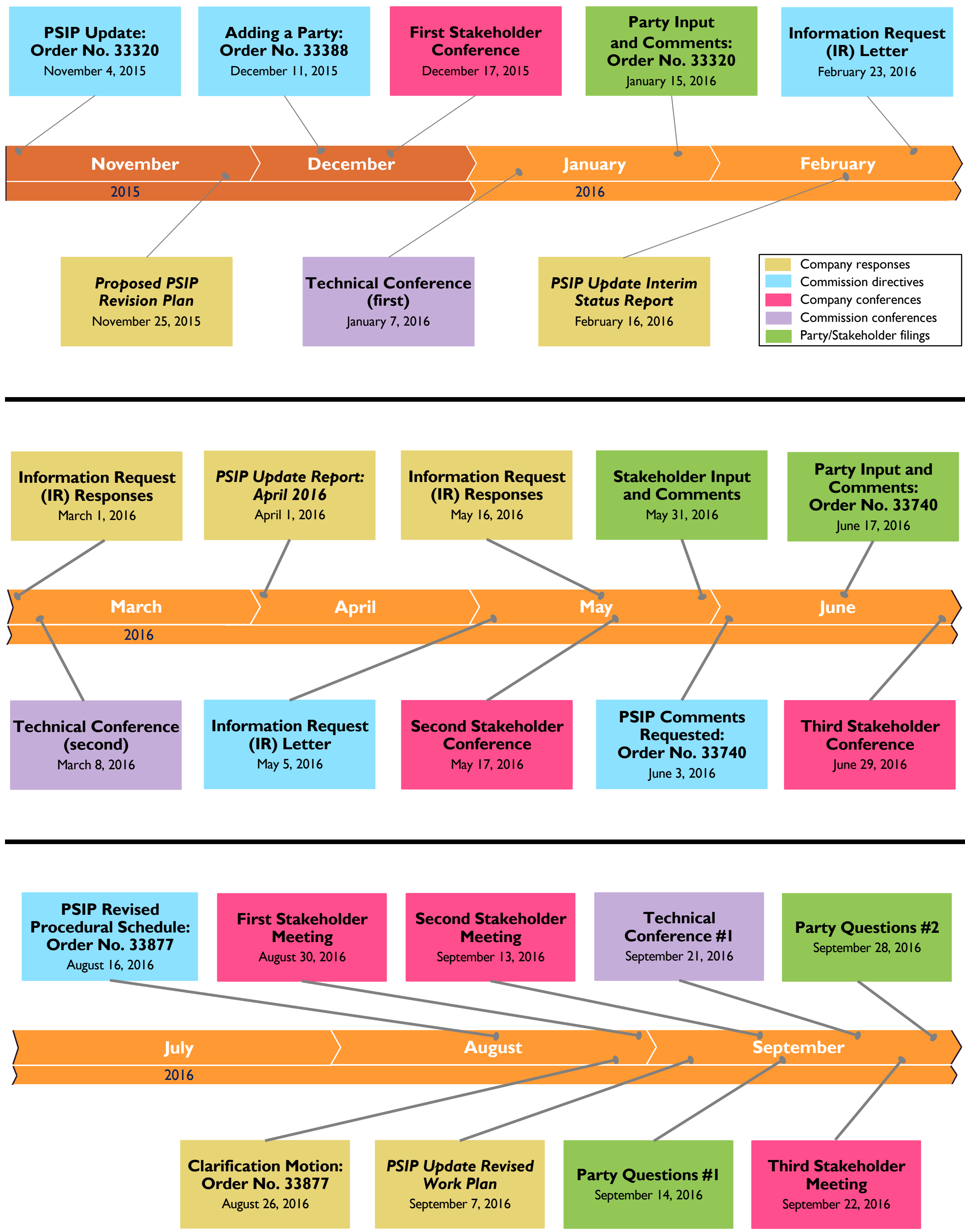
[7] Docket 2014-0183, Order No. 33877: *Hawaiian Electric Companies' Motion for Clarification of Order No. 33877*, filed August 26, 2016.

[8] Docket 2014-0183, Order No. 32257: *Instituting a Proceeding to Review the HECO Companies' Power Supply Improvement Plans*, issued August 7, 2014.

[9] Docket 2014-0183, Order No. 32294: *Inviting Public Comments on the HECO Companies' Power Supply Improvement Plans*, issued September 12, 2014, at 4.

B. Party Commentary and Input

The Updated PSIP Proceeding



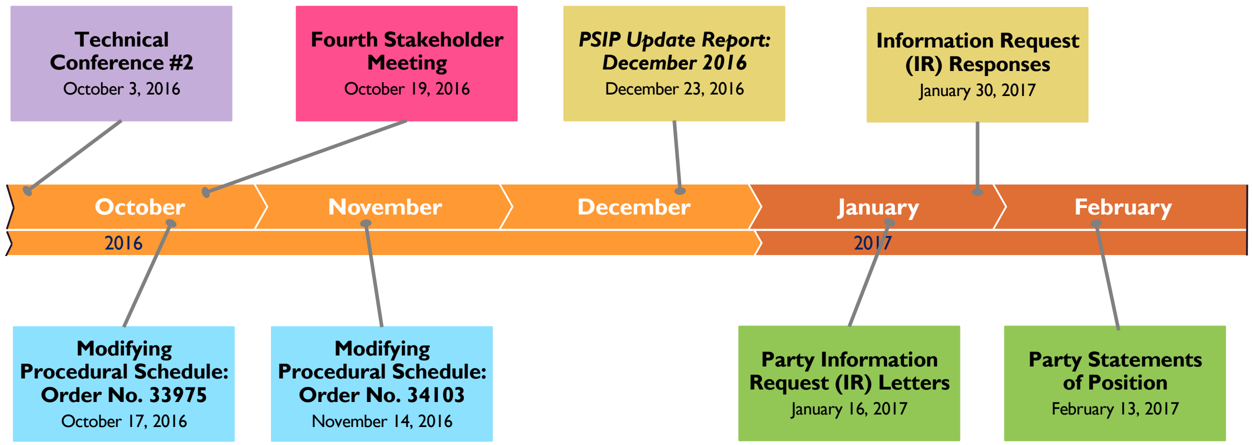


Figure B-1. PSIP Update Report Timeline

Responding to Commission Orders

The Hawai'i Public Utilities Commission, by its Order No. 32257,[10] instituted a proceeding for reviewing the Power Supply Improvement Plans (PSIPs) that were subsequently filed by the Hawaiian Electric Companies. Six additional Commission Orders (not including a protective order) directly affected this updated PSIP.

Order No. 33320.[11] Issued on November 4, 2015, this Order instituted the process for updating our 2014 PSIPs filed on August 28, 2014. The Order:

- Reiterated the Commission's guidance from their Inclinations[12] document, and detailed their eight Observations and Concerns, an Initial Statement of Issues, itemized seven component plans, and stated the purpose of the PSIP.
- Admitted 21 Intervenors and Participants—the "Parties"—to the PSIP proceeding (the Commission subsequently added two more by separate order).
- Directed the Companies to file a *Proposed PSIP Revision Plan* by November 25, 2015, an interim PSIP update by February 15, 2016, and a "supplemented, amended, and updated" PSIP by April 1, 2016. We filed these reports on their deadlines.
- Directed the Parties to respond, by January 15, 2016, to our *Proposed PSIP Revision Plan*, comment on the eight Observations and Concerns and the Initial Statement of Issues, and submit input and recommendations concerning the creation of the updated PSIP. Nineteen of the twenty-three Parties filed comments.

[10] Order No. 32257; *op. cit.*

[11] Order No. 33320; *op. cit.*

[12] Docket 2012-0036, Order 32052, *Exhibit A: Commission's Inclinations on the Future of Hawai'i's Electric Utilities*, issued April 28, 2014.

In our *PSIP Update Report: April 1*, we committed to filing an addendum by August 1, 2016 or within two months after the Energy Information Administration (EIA) published updated fuel prices. We revised our initial self-imposed filing date, setting it for September 30, 2016. The Commission, on its own motion, moved the filing to December 1, 2016,[13] then again to December 23, 2016.[14]

The Parties admitted into the PSIP proceeding included the following participants:[15]

- AES (AES Hawaiʻi, Inc.)
- Blue Planet (Blue Planet Foundation)
- Eurus (Eurus Energy America Corporation)
- First Wind (First Wind Holdings, LLC)
- Hawaiʻi Gas (The Gas Company, LLC, dba Hawaiʻi Gas)
- HPVC (The Hawaiʻi PV Coalition)
- HREA (Hawaiʻi Renewable Energy Alliance)
- HSEA (Hawaiʻi Solar Energy Association)
- LOL (Life of the Land)
- NextEra (NextEra Energy Hawaiʻi, LLC)
- Paniolo Power (Paniolo Power Company, LLC)
- Puna Pono (Puna Pono Alliance)
- REACH (Renewable Energy Action Coalition of Hawaiʻi, Inc)
- Sierra Club
- SunPower (SunPower Corporation)
- TASC (The Alliance for Solar Choice)
- Tawhiri (Tawhiri Power LLC)
- Ulupono (Ulupono Initiative)

Order No. 33320[16] also admitted the following governmental organizations as intervenors:

- CoH (County of Hawaiʻi)
- CoM (County of Maui)
- DBEDT (The Department of Business, Economic Development, and Tourism)

Order No. 32257[17] had previously admitted the Division of Consumer Advocacy (DCA) as an intervenor.

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[13] Docket 2014-0183, Order No. 33877: *Establishing a Procedural Schedule to Address the Hawaiian Electric Companies' Power Supply Improvement Plan Update*, at 33.

[14] Docket 2014-0183, Order No. 33975: *Modifying the Procedural Schedule*, issued October 17, 2016; at 5.

[15] Order No. 33320; *op. cit.*, at 163.

[16] *Ibid.*

[17] Order No. 32257; *op. cit.*, at 5.

Order No. 33320 stated these conditions to intervention and participation:

> [T]he commission reminds all Parties that it is imperative that their involvement in this docket reflect a high standard of quality, relevance, and timeliness.
>
> Insofar as the matters in this docket "require[d] specialized knowledge," the commission's decision to allow [each party] to intervene [or participate] is based, to a significant extent, on [each party's] assurances that it will provide meaningful assistance to the commission.
>
> To that end, each party's respective intervener or participant status is conditioned on the requirement that each party "possess expertise with respect to [PSIP] issues" or "retain consultants that have" "engineering, economic, and policy expertise commensurate with the highly complex and technical nature of these interrelated issues[,]" so that the matters concerning PSIPs "can be addressed in both a comprehensive and timely fashion." Furthermore, the commission encourages parties to submit alternative analyses and analytical methods into the record that will support development of final PSIPs.[18]

Order No. 33388.[19] This Order admitted the newly formed Distributed Energy Resources Council of Hawaiʻi (DERC) as a participant.

At this point, the Commission had admitted 23 Parties to the PSIP proceeding.

After being admitted to the proceeding, First Wind was purchased by SunEdison which subsequently filed for bankruptcy protection on April 21, 2016, effectively removing themselves from being a Party to the PSIP docket (although they have yet to file a formal withdrawal motion).

In Docket No. 2015-0022,[20] NextEra and the Hawaiian Electric Companies sought Commission approval for a proposed change of control. On July 15, 2016, the Commission issued Order No. 33795 dismissing the application without prejudice and closing the docket. On July 18, 2016, NextEra issued a press release announcing the termination of their plans to acquire the Hawaiian Electric Companies. On July 20, 2016, NextEra filed a motion to withdraw from the PSIP proceeding, Docket No. 2014-0183; the following day, the Consumer Advocate filed a response to not take a position on NextEra's withdrawal. The Commission subsequently granted NextEra's motion to withdraw.[21]

Thus, while FirstWind/SunEdison has not officially withdrawn, there effectively remains 21 Parties to the PSIP docket.

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[18] Order No. 33320; *op. cit.*, at 171–172.

[19] Docket No. 2014-1083, Order No. 33388: *Order Granting Motion for Enlargement of Time to Intervene or Participate, Denying Motion to Intervene, and Granting Motion to Participate*, at 14.

[20] Docket No. 2015-0022: *Application for Approval of the Proposed Change of Control and Related Matters*, instituted January 29, 2015.

[21] Order No. 33877; *op. cit.*, at 12.

Order No. 33740.[22] This Order invited comments and input from the Parties and general public about our *PSIP Update Report: April 2016*, establishing a deadline of June 17, 2016. Twenty of the twenty-three Parties filed comments, as did 174 members of the general public.

Order No. 33877.[23] This Order:

- Reiterated the PSIP-related directives from previous Orders.
- Specified Commission guidance on six additional topics.
- Directed the Companies to file a work plan for completing the updated PSIP by September 8, 2016.
- Scheduled two technical conferences: Technical Conference #1 for September 21, 2016 and Technical Conference #2 for October 3, 2016.
- Directed the Parties to file questions for each conference. The Order established a September 14, 2016 due date for the first round of questions, and a September 28, 2016 due date for the second round of questions.
- Changed the procedural schedule to incorporate these new directives, which also included moving our self-imposed deadline for filing a revision to our updated PSIP from September 30, 2016 to December 1, 2016.
- Added milestones for Information Request (IR) issuance by the Parties and response by the Companies, as well as Statements of Position by the Parties and Companies.

The Companies filed a Motion for Clarification with respect to Order No. 33877[24] to align our understanding with that of the Commission. The Commission has not issued an order on our motion.

Order No. 33975.[25] This Order modified the procedural schedule established in Order No. 33877. It moved the deadline to December 23, 2016 for filing our revision to the updated PSIP, pushed the remaining milestones out to January and February 2017, and removed the Companies' requirement for filing a Statement of Position.

Order No. 34103.[26] This Order modified the procedural schedule set in Order No. 33975 by requiring the Companies to file work papers on December 23, 2016 together with our updated PSIP, moved the IR issuance and response dates out by 10 days, and moved the Statement of Position date out one week.

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[22] Order No. 33740; *op. cit.*

[23] Order No. 33877; *op. cit.*

[24] *Hawaiian Electric Companies' Motion for Clarification of Order No. 33877*; *op. cit.*

[25] Order No. 33975; *op. cit.*

[26] Docket 2014-0183, Order No. 34103: *Modifying the Procedural Schedule*; issued November 14, 2016.

Stakeholder and Technical Conferences

A total of seven conferences (an eighth proposed) and four stakeholder meetings have been held by both the Hawaiian Electric Companies and the Commission. In every conference, the Parties were encouraged to submit comments, suggestions, and their input to the Companies to use in our modeling and analyses. At each of our stakeholder conferences and through subsequent emails, we requested input and comments from the Parties that we could incorporate into our analyses. In February 2016, we invited individuals who represented the intervenors, either in person or through a conference bridge, to attend our internal planning meetings.

First Stakeholder Conference: December 17, 2015. We held this conference for four main reasons—to accept comments and respond to questions about our *Proposed PSIP Revision Plan*; to seek input from the Parties on future pricing for resource options; to seek input from the Parties on developable levels of various renewable resource options; and to discuss any other pertinent issues raised by the stakeholders. This input and feedback affected how we developed our *PSIP Update Report: April 2016*.

Colton Ching, Hawaiian Electric Vice President of Energy Delivery, began the conference by outlining its purpose. Mark Glick, DBEDT, moderated. The Parties gave presentations. (See "First Stakeholder Conference: December 17, 2015" on page B-47 for details.)

First Technical Conference: January 7, 2016. The Commission organized a three-hour technical conference on January 7, 2016. The Commission invited representative from all Parties.

In its letter announcing this conference, the Commission stated its purpose:

> The purpose and scope of the technical conference is to further examine and understand the Revision Plan submitted by the HECO Companies on November 25, 2015, and obtain a status report on plans and progress towards the supplementation and amendment of the Companies' PSIPs. In particular, the commission seeks to ascertain (1) the resources that have been or will be obtained or retained by the Companies to perform necessary analyses, including the nature and identification of analysis models, work teams, and consultants; (2) identification of analysis approaches that have been determined; (3) identification of analyses input assumptions and sources for input assumptions that have been determined; and (4) any preliminary results.[27]

[27] Commission letter, dated December 22, 2015, signed by Robert R. Mould, Economist.

The Commission also directed the Companies to give a presentation on these topics to begin the conference. Mr. Ching made this presentation. The presentation recapped our *Proposed PSIP Revision Plan*, provided status on how we were addressing the Commission's eight Observations and Concerns, discussed supply-side resources and their related costs, and presented next steps. Mr. Ching then addressed questions from attendees.

Proposed Stakeholder Conference: February 22, 2016. We proposed a stakeholder conference for this date to discuss the filing of our *PSIP Update Interim Status Report*. In it, we proposed to review our *Power Supply Improvement Plan Update Interim Status Report* and to solicit constructive feedback, the results of any substantiated analyses from the Parties, and well-considered recommendations that we could include in our ongoing analyses. The Commission did not rule on our proposal, so the conference was not held.

Planning Meeting Attendance. After our February 22, 2016 conference, we invited intervenors to the docket to attend and participate in our planning meetings where we review analysis, make decisions on further refinements, and discuss the modeling analysis for completing the 2016 updated PSIPs. Representatives from DBEDT, the Consumer Advocate, the County of Hawaiʻi, and the County of Maui attended numerous meetings, either in person or through a phone conference bridge.

Second Technical Conference: March 8, 2016. The Commission called this 2½-hour technical conference "to provide an opportunity for the Companies to benefit from feedback from the Parties and the Commission, and assist the Commission in its review of the Companies' responses to information requests[.]"[28]

During the meeting, the Commission provided feedback on our interim status report, guidance on topics and planning elements, and asked a series of questions organized around the eight Observations and Concerns. Life of the Land, REACH, Distributed Energy Resources Council of Hawaiʻi, Hawaiʻi Renewable Energy Alliance, and Paniolo Power also asked questions. Paniolo Power indicated that they had detailed information on a pumped-storage hydro unit located at Parker Ranch. We asked them to provide complete information so that we could include it in our PSIP analysis. In early 2016, this information was only partially provided by Paniolo Power in response to our written request, but was subsequently submitted to us on October 26, 2016.

Once again, we requested all Parties to submit any input to our modeling and analysis for creating the 2016 updated PSIPs.

[28] Commission letter dated March 2, 2016, signed by David C. Parsons, Supervising Economist.

Second Stakeholder Conference: May 17, 2016. After filing our *PSIP Update Report: April 2016*, we held this Second Stakeholder Conference on May 17, 2016 (originally scheduled for April 15, 2016) to present the findings and results of our updated PSIPs. During the conference, we introduced our consultant, Energy + Environmental Economics (E3) and their work on its capacity expansion model, responded to questions and comments, and solicited additional input.

Fourteen of the Parties submitted input as a result of our request during this stakeholder conference, virtually all of which they subsequently filed in their responses to Order No. 33740 together with additional comments. (See "Second Stakeholder Conference: May 17, 2016" on page B-61 for more information.)

Third Stakeholder Conference: June 29, 2016. We held this conference at the behest of the Parties. This third conference was held to enable the Parties to make formal presentations about their input as it pertains to our continued research, modeling, and analyses for supplementing our updated PSIP scheduled originally scheduled for September 2016. As a result, four Parties made presentations. In addition, E3 presented their progress using the RESOLVE modeling tool. (See "Third Stakeholder Conference: June 29, 2016" on page B-110 for details.)

First Stakeholder Meeting: August 30, 2016. DBEDT representatives started the process for a series of meetings between the Companies and certain Parties. This first meeting essentially discussed two main topics: a suggested capacity expansion model methodology and a review of additional input assumptions. (See "First Stakeholder Meeting: August 30, 2016" on page B-123 for details.)

Second Stakeholder Meeting: September 13, 2016. This meeting explored our modeling analysis process of using RESOLVE, PowerSimm Planner, and PLEXOS to develop a resource plan and near-term action plan; speculated on the potential topics for proposed workgroups; and analyzed the regulatory process and how it might be altered. (See "Second Stakeholder Meeting: September 13, 2016" on page B-124 for details.)

Technical Conference #1: September 21, 2016. The Commission scheduled this conference in Order No. 33877 so that they could interact directly with the Companies' planning team and consultants to facilitate the finalizing of the PSIP. The Commission solicited questions, inputs, assumptions, methods, and analytical approaches from the Parties to conduct constructive conversations during the conference. (See "Technical Conference #1 and #2" on page B-120 for more information.)

Third Stakeholder Meeting: September 22, 2016. After Technical Conference #1, the Companies continued the meetings with the Parties, resuming the discussion from previous meetings and from Technical Conference #1. The meeting focused on modeling analysis, input assumptions, operational and customer-related risks, and ancillary service requirements. (See "Third Stakeholder Meeting: September 22, 2016" on page B-125 for details.)

Technical Conference #2: October 3, 2016. Order No. 33877 also included the scheduling for this technical conference as a follow-up to Technical Conference #1 held 12 days earlier. The Commission again solicited the same type of information from the Parties, based on the outcomes from the previous conference. The Commission's intent for this conference was the same as the previous one: to facilitate the finalizing of the PSIP. (See "Technical Conference #2: October 3, 2016" on page B-121 for more information.)

Fourth Stakeholder Meeting: October 19, 2016. At this fourth meeting, the Parties validated and confirmed the input assumptions that we garnered from Technical Conference #1 and #2, and from the previous stakeholder meetings. These input assumptions included on-island wind and PV for O'ahu, wind and pumped storage hydro input, LNG, plus a number inputs for various sensitivities (such as the hedge value of renewable generation and lowest cost plan regardless of RPS). We then directed E3 to run sensitivity analyses on each of these input assumptions. (See "Fourth Stakeholder Meeting: October 19, 2016" on page B-127 for details.) A week later, the Parties submitted additional detailed information about much of this input. E3 analyzed the findings from the sensitivity analyses to assess their impact on the near-term action plan.

INPUT INCORPORATED INTO OUR PSIP UPDATE REPORT

Since the advent of this PSIP Update proceeding, we have actively sought input from the Parties during our three stakeholder conferences and four stakeholder meetings. To direct this input, we have provided data to the Parties on several occasions.

- On February 2, 2016, we voluntarily provided new resource input assumptions, posting this information on a WebDAV site accessible by the Parties.
- On February 16, 2016, in our interim status report, we included proposed methods of analysis, input assumptions, and other information.
- On February 29, 2016, we responded to a lengthy and comprehensive set of Commission-issued Information Requests, covering virtually all of the areas previously questioned by the Parties.
- On April 1, 2016, we filed our *PSIP Update Report: April 2016*.
- On June 24, 2016, we voluntarily provided updated new resource input assumptions.
- On September 7, 2016, we filed our work plan for completing the updated PSIP, which detailed our modeling analysis process.

We have considered and incorporated *all* pertinent input and related comments, as well as comments the Parties filed in response to four Commission Orders.

For our *PSIP Update Report: April 2016*, we considered and incorporated Party input and comments received as a result of our First Stakeholder Conference and Party filings in response to Order No. 33320, which also included perspectives gained from the January 7, 2016 Technical Conference.

For our *PSIP Update Report: December 2016*, we considered and incorporated Party input and comments received as a result of two additional stakeholder conferences and four stakeholder meetings as well as Party filings in response to Order No. 33740 and Order No. 33877 (for Technical Conferences #1 and #2).

Much of the information we received, considered, and incorporated from Party filings in this proceeding was procedural. How we responded to this procedural input is detailed in “Order No. 33320: Party Input and Our Response” starting on page B-51, and in “Order No. 33740: Party Input and Our Response” on page B-91.

Party Responses to Commission Orders and Company Requests

We received five iterations of comments and input from the Parties: from Order No. 33320, in response to our solicitation during the Second Stakeholder Conference, in response to Order No. 33740, in preparation for Technical Conference #1, and in preparation for Technical Conference #2.

Order No. 33320. Nineteen of the twenty-three Parties filed "initial responses" to our Revision Plan as encouraged in Order No. 33320. Appendix B. Input from the Parties in our *PSIP Update Report: April 2016* explains how we engaged the Parties; details the comments, suggestions, and input submitted by the Parties; and how we considered and incorporated this input into our research, modeling, and analysis. Most of that information is repeated here in "First Stakeholder Conference: December 17, 2015" on page B-47 and in "Order No. 33320: Party Input and Our Response" on page B-51.

Second Stakeholder Conference, May 17, 2016. After filing our *PSIP Update Report: April 2016*, we held a Second Stakeholder Conference to review the results of our PSIP. At the conference, we solicited additional comments and input from the Parties that we could incorporate into our modeling analysis for our subsequent *PSIP Update Report: December 2016*.

Order No. 33740. In addition, the Commission issued Order No. 33740 inviting the Parties and "interested persons who are not Parties to this docket" to submit comments on our *PSIP Update Report: April 2016*. The Commission stated that submitters "are free to comment upon any aspect of the PSIPs; however, the Commission is particularly interested in comments that address the Initial Statement of Issues. In addition, the Parties are encouraged to address what specific procedural steps the Commission should consider to ensure constructive further progress in this docket." The Order outlined these Initial Statement of Issues with a reference to Order No. 33320 that describes these issues in detail. The Commission set a June 17, 2016 deadline for submissions. "Order No. 33740: Summaries of Filed Responses" (page B-67) summaries those comments; "Order No. 33740: Party Input and Our Response" (page B-91) categorizes those comments and our responses.

Technical Conference #1. For this conference, 19 of the Parties submitted questions, inputs, assumptions, methods, and analytical approaches for us to consider and incorporate into our modeling analyses and resource planning.

Technical Conference #2. Nineteen of the Parties again submitted questions, inputs, assumptions, methods, and analytical approaches based on the discussions from Technical Conference #1.

Table B-1 outlines the Party input from these sources.

Stakeholder	Order No. 33320	Second Stakeholder Conference	Order No. 33740	Technical Conference #1	Technical Conference #2
Intervenor					
County of Hawai‘i	√	√	√	√	√
County of Maui	√	√	√	√	√
Department of Business, Economic Development, and Tourism	√	–	√	√	√
Division of Consumer Advocacy	√	–	√	√	√
Party					
AES Hawai‘i	–	√	√	√	–
Blue Planet Foundation	√	√	√	√	√
Distributed Energy Resources Council of Hawai‘i	√	√	√	√	√
Eurus Energy America	√	–	–	√	√
First Wind Holdings (acquired by SunEdison)	√	–	–	–	–
The Gas Company (dba Hawai‘i Gas)	√	√	√	√	√
The Hawai‘i PV Coalition	√	–	√	√	–
Hawai‘i Renewable Energy Alliance	–	√	√	√	√
Hawai‘i Solar Energy Association	√	√	√	√	√
Life of the Land	√	–	√	√	√
NextEra Energy Hawai‘i	–	–	–	n/a	n/a
Paniolo Power Company	√	√	√	√	√
Puna Pono Alliance	–	–	√	√	√
Renewable Energy Action Coalition of Hawai‘i	√	√	√	–	–
Sierra Club	√	√	√	√	√
SunPower Corporation	√	√	√	√	√
The Alliance for Solar Choice	√	√	√	√	√
Tawhiri Power	√	–	√	–	√
Ulupono Initiative	√	√	√	√	√

Legend: √ = submitted input; – = no input submitted

Table B-1. Outline of Party Comments and Input by Source

Cases and Sensitivities

In detailed discussions and collaborations with the Parties at Technical Conference #1 and Technical Conference #2, the four stakeholder meetings, and subsequent conference calls, together we agreed on a list of sensitivities for our modeling analyses.

Core Cases

These are the core cases that we modeled in PLEXOS. The post-April PSIP plans are a result of our actions as specified in Chapter 7: Next Steps of the December 2016 PSIP update;[29] all of E3's plans are a result of their analysis as described in our PSIP Work Plan.[30] All core cases were modeled with the high DG-PV forecast with DR.[31]

The core cases vary by island:

O'ahu

We are modeling five core cases for O'ahu:

1. Post-April PSIP Plans
2. E3 Plan
3. E3 Plan with LNG
4. E3 Plan with Generation Modernization
5. E3 Plan with LNG and Generation Modernization

Maui and Hawai'i Island

We are modeling the first three core cases as run for O'ahu:

1. Post-April PSIP Plan
2. E3 Plan
3. E3 Plan with LNG

Lana'i and Moloka'i

We are modeling two different core cases for Lana'i and Moloka'i:

1. 100% Renewables by 2020
2. 100% Renewables by 2030

29 *Op. cit.*; *Power Supply Improvement Plan Update Report: April 2016.*

30 Docket 2014-0183; *PSIP Update Revised Analytical Approach and Work Plan*, filed September 7, 2016.

31 These core cases are described in greater detail in Chapters 3: Analytical Approach. Chapter 4: Analytical Results discusses the results for each island.

Interisland Transmission

Interisland transmission was modeled between O‘ahu, Maui, and Hawai‘i Island by E3 as a "copper-plate" configuration (that is, all three islands are bus-bar connected).

Sensitivities

All Party input culminated into input assumptions analyzed as sensitivities to the E3 Plan. The Companies' consultant, E3, ran these sensitivities on each of the above cases in an order that, when possible, builds on or adds a different dimension to the results of the previous sensitivity.

1. Hedge value of renewables (using various fuel price forecasts including biomass, fossil fuels, and LNG) on O‘ahu, Maui, and Hawai‘i Island.
2. Higher grid-scale solar and wind resource potential only on O‘ahu based on Ulupono's (Dr. Fripp's) assumptions.
3. LNG pricing only on O‘ahu based on Hawai‘i Gas's pricing.
4. Pumped storage hydro and wind profiles only on Hawai‘i Island based on Paniolo Power's proposed project assumptions.
5. Least-cost plan regardless of RPS attainment on O‘ahu, Maui, and Hawai‘i Island based on the Consumer Advocate's suggestion.
6. Generation modernization on O‘ahu.
7. Department of Defense projects on O‘ahu where RESOLVE determines which resources are selected and which are not.

Party Modeling Input and Suggestions: A Summary

Over the course of the PSIP proceeding, we have received and considered all Party input and commentary, and incorporated pertinent information in our PSIP modeling process. Here, we discuss the input and process suggestions we've incorporated. Some of this information came to us in the middle of 2016, while much of it came in the fall and as late as the end of October—less than two month before the filing deadline. We have done our best to incorporate this information into our modeling process given the time constraints.

Several parties—notably Hawai‘i Gas, SunPower, Ulupono, and Paniolo Power—engaged in fact-based discussions with us regarding input assumptions for our modeling analyses. As a result, we considered and analyzed their input on resources central to our analyses: LNG, PV potential, O‘ahu renewable resource potentials, and pumped storage hydro. Summary descriptions of our discussion appear below; detailed descriptions of our collaborations surrounding this Party input (including their specific data) follows these summaries (starting with the "Hawai'i Gas Input: Liquefied Natural Gas" section on page B-25.

Virtually all of the Parties, through their filings and through our technical and stakeholder conferences, commented on our input assumptions and analytical process, and about regulatory procedures. We thoughtfully considered all of their commentary and incorporated all comments directly connected with our development of the PSIP. DBEDT, Ulupono, and Paniolo submitted specific modeling suggestions. Summary descriptions of these suggestions and how they affected our modeling appear below (see "Party Modeling Suggestions" on page B-22).

Ultimately, through these discussion and a series of meetings with these parties, together we agreed that the Companies seriously considered and addressed their input and concerns, and collaboratively arrived at mutually agreed upon input assumptions. After these many deliberations, while we ran a number of sensitivities using Party input, virtually all of our foundational input assumptions remained unchanged.

Hawai'i Gas: LNG. Hawai'i Gas formally provided information about their LNG proposal in their response to Order No. 33740 on June 20, 2016 (and reiterated that information in their response to Order No. 33877). We compared their LNG fuel price forecasts with the LNG forecasted input assumptions that we employed when developing our *PSIP Update Report: April 2016*. The average difference between the two was approximately $0.11 per MMBtu. On June 27, 2016, we sent an email to Hawai'i Gas that detailed 29 questions regarding their response to Order No. 33740; they did not respond to our questions.

On October 28, 2016, Hawai'i Gas provided more detailed information following our solicitation for input at our Second Stakeholder Conference and our Fourth Stakeholder Meeting. This information detailed their contract pricing for various levels of metric tons per annum (mtpa), and added observations on the basis of their forecast, infrastructure costs, volume effects, multiple index options, and hedging and volatility. In the end, Hawai'i Gas acknowledged that their costs were very similar to ours; thus, using our data as input would not materially affect the results of our modeling analysis as opposed to using their data. We also agreed on one main point: when compared to oil, LNG is cleaner burning and lower priced.

Hawai'i subsequently requested that we use a higher LNG volume of 0.9 mtpa . This value represents the sum of our projected volume (0.6 mtpa) and Hawai'i Gas's projected volume (0.3 mtpa), which Hawai'i Gas confirmed does not include volume for the KPLP power plant.

SunPower: PV Potential. Following our Second Stakeholder Conferences and in response to Order No. 33740, SunPower submitted a U.S. Department of Energy *SunShot Vision Study* (dated February 2012) about the potential of PV in the greater United States together with PV system costs and forecasts from GTM Research. The Companies sent SunPower a series of questions about this input, to which SunPower diligently responded. SunPower and the Companies engaged in a number of very constructive conversations about this information and about energy storage capital costs. Ultimately, we could not justify using the lower capital cost projections for solar PV in Hawai‘i suggested by SunPower. Further, our energy storage costs were similar to those recommended by SunPower. In the end, we agreed that our cost estimates, while not exactly the same as theirs although similar, would be used in our modeling analysis.

SunPower did suggest separating residential from commercial DG-PV pricing in future analysis. In Chapter 7: Next Step, we have noted our intention to follow their suggestion in subsequent updates to our PSIP.

Paniolo Power: Pumped Storage Hydro and Grid-Scale Wind. At our Second Stakeholder Conference, Paniolo Power indicated they had assembled information regarding pumped storage hydro. Paniolo also provided commentary and suggestions in their response to Order No. 33740, and three Siemens reports in their response to Order No. 33877: *Hawai‘i Island Generation Supply Transformation Plan* (redacted, dated May 14, 2105; filed over a year later on September 14, 2016), *Study of Electric Supply Options for the Island of Hawai‘i* (dated July 2015; filed over a year later on September 28, 2016), and *Study of Pumped Storage Hydroelectric for the Island of Hawai‘i* (dated February 11, 2016; filed September 28, 2016). All three reports presented discussion and results of analyzing wind energy in combination with pumped storage hydro (PSH). Eurus also provided a paper summarizing a proposed PSH project on O‘ahu.

From first notice, we engaged in a number of discussions with Paniolo, requesting details regarding their studies. Their response was not immediately forthcoming, then partially submitted, which forestalled our evaluation of their studies. Eventually, on October 26, 2106, Paniolo did provide detailed data, however, *some of it was outdated and almost all of it was virtually identical to the input we were using in our modeling analyses*. One main difference was their 85% turnaround efficiency rating versus our 80%. In a subsequent email, Paniolo acknowledged that 80% was the more prudent percent to model.

During our Fourth Stakeholder Meeting, Dr. Fripp interestingly noted that his SWITCH optimization model for O‘ahu chose battery energy storage systems (BESS)—because of their declining costs—over PSH and its relatively flat cost. Nonetheless, in the end, we used our 2016 PSH cost assumptions (which were lower than Paniolo’s) for our modeling analyses.

In early November 2016, Paniolo informed us they were developing wind data that would be available in about a month, but that estimated wind data for use in our modeling analyses could be available in "a day or two". We told them that a month out for wind data is too late to include in our modeling, but we might be able to incorporate the estimated wind data. Paniolo did provide us with the foresaid estimated wind data about a week later on November 11, 2016. We forwarded this information to E3, and E3 was able to incorporate this into their analysis. Paniolo subsequently provided site specific data analyzed by AWS Truepower on December 5, 2016. (This eight-page redacted report and companion one-page summary is reproduced in "Paniolo Power Wind Resource and Energy Production Assessment" on page B-130.) We informed Paniolo Power that E3 was nearly complete with its analytical work and would not be able to incorporate this information.

Ulupono: O'ahu Grid-Scale PV and Grid-Scale Wind Potentials. Dr. Matthias Fripp, a professor at the University of Hawai'i and representing Ulupono (and at one point, Blue Planet), suggested changes to the NREL study being conducted to determine the on-island renewable resource potential for O'ahu. Those suggestions includes expanding the land slope of grid-scale PV installations from 5% to 10%, and to expand land selection to include Agricultural grade "B" and grade "C" designations.

As a result, we instructed NREL to rerun their study; Appendix F: NREL Reports contains their updated report and our related assessment of its results. In the end, we agreed to use this suggested expanded basis in our modeling analysis to determine the maximum *theoretical* potential of grid-scale PV and grid-scale wind on O'ahu. We also asked NREL to review the assumptions suggested by Dr. Fripp. NREL concluded that the primary difference in assumptions relates to land-use; NREL states that a more accurate resource potential estimate would require a site-by-site assessment across the entire island of O'ahu.

In addition, Dr. Fripp provided research about rooftop potential for DG-PV, wind potential, and grid-scale solar PV capacities on O'ahu. This research showed a theoretical potential total of 3,022 MW of direct-current PV from residential rooftops, a theoretical potential total of 2,680 MW of grid-scale wind, and (based on a 20% land slope) a theoretical potential total of 9,168 MW of grid-scale fixed PV potential or 8,010 MW of grid-scale tracking PV.

See "Grid-Scale PV and Grid-Scale Wind Potential" in Appendix H: Renewable Resource Options for O'ahu for a more detailed discussion of the realities surrounding the potential of these on-island resources.

Finally, after our Fourth Stakeholder Meeting, Ulupono, together with Dr. Fripp suggested a number of changes to our modeling process. One was to modify their solar supply curve data by segregating larger and smaller curves, and by estimating the cost of a small scale (approximately 2 MW) solar project, which creates correct economic, dispatch, and weather correlations. A second was to modify the modeling algorithm to incorporate the risks of cost hedging. A third was to reorder the sequence of running various cases and sensitivities. This suggestion was spawned because DBEDT expressed a need to directly compare action plans identified by the analysis on similar footings. DBEDT identified a number of common factors for comparing action plans to better identify the conditions under which a particular best performs. And a fourth was to use multiple blocks with different capacity factors for each resource.

Together with E3, we worked with Ulupono and their consultant Dr. Fripp to incorporate these suggestions into the sensitivity analyses work.

DBEDT: Near-Term Action Plan Sensitivities. DBEDT requested that E3 use RESOLVE to test the robustness of our findings based on their proposed five-step methodology. DBEDT felt the proposed near-term action plan (and anything that might change in it) was highly sensitive to long-term forecasts of uncertain variables: fuel price, renewable price, and storage price forecasts as well as the impact of the interisland transmission. After some discussions, together we eliminated the three forecasts as problematic because the near-term action plan did not include LNG nor recommend new thermal resources. In a subsequent phone call, E3 confirmed that the "copper-plate" interisland analysis only increased the amount of renewable generation that RESOLVE selects for the near-term action plan.

We also tested a sensitivity of not including the MCBH and JBPHH microgrid projects, as DBEDT requested. The results of the analysis chose not to build these microgrids, but included the building of new biodiesel projects in 2045.

TASC: Load Banks. The Alliance for Solar Choice (TASC), at our Third Stakeholder Conference, suggested employing dispatchable load banks to consume otherwise curtailed renewable energy, or "spinning renewable energy". TASC cited a very small project as way of an example. Load banks may have value to mitigate contingency curtailments. Without understanding how load banks could improve on our analysis and potentially reduce costs, we did not consider load banks in our resource assumptions.

LOL: Hydrokinetic Energy Technologies. After our Third Stakeholder Conference, Life of the Land suggested that all of O'ahu's generation could be provided by ocean (hydrokinetic) energy technologies. We reviewed this and several other related reports. All of these reports not only failed to demonstrate the possibility of viable installations or of imminent technological breakthroughs, but also pointed to the extreme cost of this immature technology. Our research could not find any evidence of commercially available hydrokinetic technologies that would be appropriate for Hawai'i. As a result, we did not consider ocean energy technologies in our analyses. (See Appendix H:

Renewable Resource Options for O'ahu for an in-depth analysis of this latent technology.)

HREA: Biomass Fixed O&M and Fuel Costs. In September 2016, HREA, acting on behalf of Hu Honua who is not a Party to the PSIP docket, submitted biomass assumptions. Specifically, Hu Honua stated that our biomass fixed O&M and fuel cost assumptions were too low compared to theirs. Hu Honua appears to be attempting to influence the PSIP results to reflect its higher costs. HREA, itself, asserted that our PSIP assumptions should not be used as a baseline against which to compare actual projects.

We concur that our biomass assumptions differ from those submitted by Hu Honua. In June 2016, independent of Party input, we had already revised our biomass projections for greater accuracy. Despite Hu Honua's and HREA's belated attempts, we used our revised assumptions in our modeling analysis.

Party Modeling Suggestions

DBEDT, Ulupono, and Paniolo Power each suggested analytical methodologies for us to model as sensitivities.

DBEDT: Additional Modeling Framework. In their response to Order No. 33877 requesting questions in preparation for Technical Conference #1, DBEDT suggested an additional methodology for modeling our action plans. In an October 27, 2016 email following our Fourth Stakeholder Meeting, DBEDT reiterated this suggestion and included an explanation of its rationale. DBEDT's suggested analytical methodology is reproduced here (formatted for clarity).

> DBEDT envisions that the five-year action plan optimization would be the result of the following, or a substantially similar, multi-step process:
> (1) the capacity expansion models will be run under a variety of scenarios with the optimization period being 30 years;
> (2) the capacity expansion model would be provided choices of options and/or constraints;
> (3) the resulting five-year action plans from each scenario that was optimized over 30 years would be compared to identify a discrete number of candidate five-year action plans that warrant further assessment;
> (4) the candidate five-year action plans would be fixed in the capacity expansion model and runs would be made again under the same scenarios in step 1 to identify which five-year action plan is most resilient under an uncertain future; and
> (5) the five-year action plan that is deemed to be most resilient would be subject to detailed analysis to assess for system security among other things.[32]

[32] *Pre-Technical Conference Comments of the Department of Business, Economic Development, and Tourism*, filed in Docket No. 2014-0183 on September 14, 2016; at 8.

DBEDT presented examples of options and constraints:

- With and without interisland transmission.
- With and without offshore wind.
- Varying levels of available geothermal, wind, solar, biofuels, and other generation types per island.
- Accelerated renewable targets.

DBEDT suggested that resiliency could be assessed by identifying a variety of metrics, such as system average rates, standard deviation of the system average rates under various fuel price and load scenarios, and system reliability; and that this analysis would result in either a preferred plan or a limited set of candidate plans. DBEDT stressed the critical nature for following their suggested methodology.

DBEDT explained that the purpose of this methodology was to be able to directly compare—on an "apples to apples" basis—Company action plans that resulted from our modeling of various cases and sensitivities, including a focus on financial investments. Absent this process, the only debatable differentiator among the action plans would be a prediction of the expected future state of the energy sector.

Their methodology stated that E3, through their RESOLVE model, would need "to fix the five-year action plans as inputs and perform a series of runs for each (fixed) action plan under the scenarios and sensitivities that resulted in the candidate five-year action plans." Performing this methodology would give us "a better position to analyze the merits of individual actions and investments."

Ulupono: Suggested PSIP Methodology. For our First Stakeholder Meeting on August 30, 2016, Ulupono proposed a PSIP methodology comprised of these four steps:

1. *Policy Scenarios.* Define major large-scale infrastructure on policy choices that would significantly impact the electric grid (such as siting interisland cable, geothermal, LNG, offshore wind projects, and accelerated EV and DER penetration). Develop a matrix to optimize possible scenarios of these options, then systematically remove choices to assess results.

2. *Major Assumptions.* Develop the following assumptions, then vet and modify them through Party working groups: 1. Inputs and model formulations being used in the E3 RESOLVE model; 2. Add all resource inputs excluded from the E3 model; 3. Capital costs over time; 4. Criteria and algorithms used to define MW and their supply curves for major renewable resources; 5. Hourly profiles used to define projected output; 6. Costs related to operating or deactivating utility-owned and IPP plants; 7. LNG, coal, and oil fuel assumptions; and 8. Hourly loads and demand response potential.

3. *Capacity Expansion Model.* Run RESOLVE (or SWITCH) to select least-cost resources through iterations with system reliability models, DER models, and risk and volatility algorithms. The DER models should inform DER uptake and possible shifts in load shape, and allow for grid support services. The risk and volatility algorithms can be used to develop hedged fuel prices to assess risk tolerance, or employ a Monte Carlo approach to "project" a large number of fuel price trajectories.

4. *Five-Year Action Plans.* Assess the resultant action plans to determine near-term actions necessary to reach the 100% renewable target with the least difficulty and to increase the longer-term opportunity for other resources as they become available.

Figure B-2 depicts Ulupono's representation of their suggested PSIP methodology.

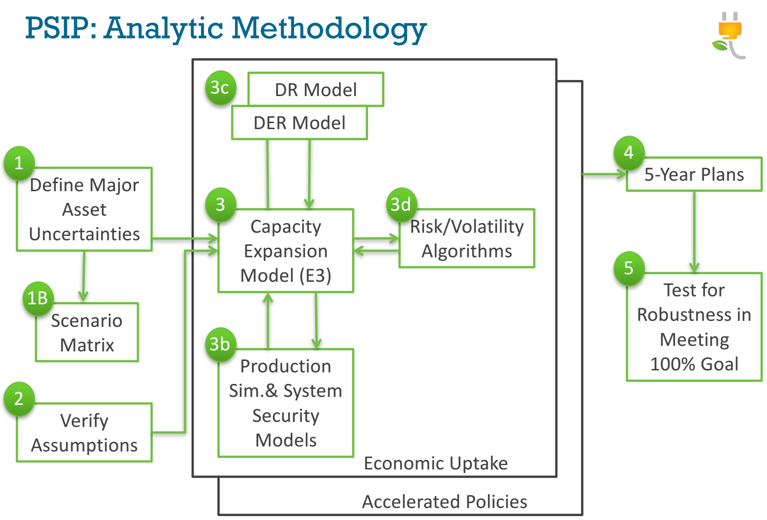

Figure B-2. Alternative PSIP Analytical Methodology

Ulupono suggests running the SWITCH model with a framework called the Progressive Hedging Algorithm (PHA) to address the best near-term actions that consider how to adapt to changing conditions. The recommended process involves generating a million fossil fuel price trajectories for the next 35 years, assess groups of 100–200 trajectories to choose up to 200 least-cost candidate plans, optimize the plans for longer-term conditions, plot the average and range of long-term costs, then employ a stakeholder process to manually select a preferred plan. Repeat the assessing, optimizing, and selecting steps for each policy scenario (from step 1 above) to create a preferred plan for each scenario, then again employ a stakeholder process to manually identify the most plausible policy scenario or important questions to settle before choosing the final preferred plan.

Ulupono offered a timeline for implementing their methodology. Subsequent meetings and discussions successfully resulted in narrowing Ulupono's input into a sensitivity analysis. (See "Sensitivities" on page B-17.)

Paniolo Power: Hawai'i Island Capacity Expansion Planning. At our First Stakeholder Meeting (August 30, 2016), Paniolo Power recommended that Siemens (together with a third-party independent observer) use their AURORAXMP model to perform the capacity expansion modeling for Hawai'i Island. Paniolo contended that the modeling being performed by the Companies and our consultants does "not work well on the neighbor islands". Paniolo listed five reasons for their recommendation.

Paniolo suggested that three policy issues be addressed: 1. LNG as a bridge tool compare with an immediate transformation to all renewable resources; 2. Interisland transmission between O'ahu and Hawai'i Island if O'ahu cannot achieve 100% renewable generation with on-island resources; and 3. Costs and benefits of grid resiliency through varying sizes of integrated energy districts (essentially, microgrids).

Paniolo suggested the planning to attain 100% renewable generation should first be applied solely to Hawai'i Island. This planning should replace the annual fuel cost input with the equivalent annual unamortized renewable energy capital investment; and should examine large wind or solar PV facilities coupled with energy storage, and if these facilities can coexist with integrated energy districts. Then the energy bill impact of the benefits and costs of resiliency versus customer benefit could be explored.

Resource planning assumptions would include: a focus on wind and solar PV, BESS or PSH for storage, small CTs or ICEs replacing less efficient generation, PPAs not extended, no assumption of HEP ownership, and a unit retirement plan coupled to the timing of constructing energy storage resources. Paniolo concluded with a timeline that parallels current Company modeling and planning.

Subsequent meetings and discussions successfully resulted in narrowing Paniolo Power's input into a sensitivity analysis. (See "Sensitivities" on page B-17.)

Hawai'i Gas Input: Liquefied Natural Gas

When developing our *PSIP Update Report: April 2016*, we compared Hawai'i Gas's LNG fuel price forecasts (Table B-2) with our LNG forecasted input assumptions (Table B-5) and found the average difference between the two was approximately $0.11 per MMBtu. Because of that small difference, we used our LNG input assumptions in our modeling analyses.

Hawai'i Gas LNG Proposal

On May 31, 2016, Hawai'i Gas formally provided information about their LNG proposal in response to our solicitation for input at our Second Stakeholder Conference. On June 20, 2016, Hawai'i Gas again provided detailed information about their LNG proposal in response to Order No. 33740.

After reviewing this more detailed input, we emailed Hawai'i Gas (on June 27, 2016, copying all Parties) requesting more information so that we could better compare their LNG fuel price forecasts and assumptions with ours. That email contained 29 questions—reproduced here—distributed among four areas: volume and pricing assumptions, timing, contract structure, and supply chain.

1. Volume and Pricing Assumptions

   a. What are the minimum and maximum LNG take obligations for Hawai'i Gas (HG) to offer the pricing in Table A of your May 31 Comment Letter? What are the penalties, if any, for not meeting the minimum take obligation as it may exist? Are volume commitments adjustable over the 15-year term without penalties?

   b. Please elaborate on the correlation between HG's pricing and volume commitments. In your June 20 Hawai'i Public Utilities Commission (HPUC) Letter, the values in Table 10 do not seem to match Tables 2 or 4. Please clarify. What portion of the "Other Costs" makes up the FSRU?

   c. What are the fixed and variable cost components associated with the HG LNG pricing proposal? What percentage of the total delivered price is associated with the underlying commodity? Is the pricing provided by HG contingent upon other off-takers, in addition to Hawaiian Electric and HG, contracting with the LNG supplier? Does the pricing in Table A represent the same price for all users of the HG supply chain? What would the delivered price be if Hawaiian Electric was the only off-taker? What price would Independent Power Producers pay for LNG and what would be their contract structure?

   d. Excluding commodity prices, are the prices provided subject to change? If so, please explain why and how they may change.

   e. The Hawaiian Electric Companies' updated PSIP lays out road maps for achieving 100% renewable energy with LNG as a transitional fuel and does not contemplate electricity users transitioning to self-supply generation using fossil fuels, which are currently not subject to the RPS. Does HG intend to offer gas from its intended LNG supply chain to self-generators? Please provide HG's views on this potential issue.

   f. Please provide the calculation to convert from capital cost dollars to a $/MMBtu price and indicate what assumptions were made.

g. The HG "Facts About LNG for Hawai'i" report includes neighbor island utility volumes, but does not identify a means to deliver LNG to the neighbor islands. Are the HG pricing calculations contingent upon volume off-takes at any neighbor island utilities (such as Maui Electric or Hawai'i Electric Light), and if so, in what volumes?

h. What toll would Hawaiian Electric pay for using the new pipeline (s)? Is the total a fixed $/MMBtu number or variable based on volume?

i. The prices supplied in Table A do not represent the latest EIA data for 2016. Will the tables be updated accordingly?

j. Please provide the per MMBtu cost that HG anticipates charging Hawaiian Electric for deliveries of LNG to Kahe, and to Maui and Hawai'i Island. Please confirm if the indicative per MMBtu cost is fixed or variable based on volume.

k. Is a 100% indexation to North American gas available? If so, please provide one.

2. Timing

   a. Who will bear the schedule risk if this in-service date is not met?

   b. Is the LNG supplier willing to hold its price relationship to Brent or Henry Hub for a potential lengthy regulatory approval window?

3. Contract Structure

   a. Please explain the commercial structure of the supply chain described in your May 31 Comment Letter.

   b. What is the "firmness" of the LNG supply delivered to Hawaiian Electric's facilities? Will there be liquidated damages available to Hawaiian Electric in the event of non-delivery to cover the incremental cost of Hawaiian Electric sourcing an alternate fuel?

   c. Can the contract be extended beyond 15 years to address the gap between contract termination and 100% renewables, and if so, what is the incremental cost to extend?

   d. HG states that it has a "binding RFP". In what specific respects is the RFP binding on the bidders? For how long? What form of contract has HG signed with the bidders to make the RFP binding? Is HG negotiating a contract for all potential off-takers in Hawai'i?

   e. Which entity would be contracting with the LNG supplier? What, if any, credit requirements would be required of Hawaiian Electric to support HG's 15 year contract?

- **f.** On page 2 of your June 20 HPUC Letter, HG asserts that the FSRU will be owned and operated by a third-party and that the LNG supply vessel will be owned and operated by a third-party. Are these the same third-party and, if not, how many contracts will Hawaiian Electric be required to negotiate? Who will bear the cost risk if one party fails to perform?
- **g.** Which entity will fund the FERC process discussed in your June 20 HPUC Letter and which entity will be financially responsible if the process is delayed? What "similar" projects have completed the FERC process in 30–36 months as stated by HG?
- **h.** On page 5 of your June 20 HPUC Letter, HG states that the contract can be terminated early. Is there an early termination fee or other negative contractual consequences? If so, please describe them.

4. Supply Chain

- **a.** What is the ratability of the HG supply chain? Are there additional costs to cover periods that LNG cannot be offloaded to the FSRU because of weather conditions or insufficient storage availability in the FSRU?
- **b.** What are the logistics planned to serve the neighbor islands with LNG from the FSRU and what are the associated costs?
- **c.** Under which easement would a gas pipeline to Kahe Power Plant be built? If HG intends to use Hawaiian Electric's existing oil pipeline easement, is there room for a new gas pipeline alongside the existing oil pipeline which may need to remain intact for contingent liquid fuel supply?
- **d.** What gas pressure would be supplied to Kahe Power Plant?
- **e.** For Maui and Hawai'i Island, does HG propose to supply LNG or natural gas? If natural gas, what is the supply gas pressure?
- **f.** Where will the natural gas for HG's LNG supply chain be sourced from and what is the supply risk?
- **g.** On page 2 of your June 20 HPUC Letter, HG states that the pipeline infrastructure will be five to ten miles. What length of pipeline and what route was assumed to generate the estimates in Table 1?
- **h.** On page 3 of your June 20 HPUC Letter, HG states that the FSRU is already in service. When will the FSRU will be available for service in Hawai'i, what will be the cost to refurbish and deliver the FSRU to Hawai'i, and is the FSRU design suited for Hawai'i's needs?

Hawai‘i Gas did not respond to these questions.

In an email sent on October 28, 2016, Hawai‘i Gas provided more detailed information following our solicitation for input at our Second Stakeholder Conference and our Fourth Stakeholder Meeting. This information detailed their contract pricing for various levels of metric tons per annum: 0.3 mtpa, 0.4 mtpa, 0.5 mtpa, 0.6 mtpa, 0.7 mtpa, 0.8 mtpa, 0.9 mtpa, and 1.0 mtpa pricing. Each mtpa volume listed prices in both 2015 and nominal dollar amounts for LNG-only delivery, infrastructure cost, and the "all-in" cost of delivery plus infrastructure. The email contained five sections, outlining their additional observations on the forecast basis, fixed versus constant infrastructure costs, aggregating volume effects, multiple LNG price index options, and hedging and volatility.

In the subsequent email exchanges, the Companies and Hawai‘i Gas acknowledged that economies of scale affect pricing (the larger the volume, the lower the per unit cost) and that the need for LNG would decline as our RPS attainment increased.

Hawai‘i Gas confirmed that they expect to deliver 0.3 mtpa of LNG annually (without decline over time and does not include volumes for the KPLP power plant). Our projections set our annual delivery expectations at 0.6 mtpa of LNG. Thus, we used a combined total of 0.9 mtpa of LNG in our modeling analysis. Over the years, we gradually reduced that volume as increasing amounts of renewable generation replaced LNG-fired generation.

Subsequent meetings and discussions successfully resulted in narrowing Hawai‘i Gas's input into a sensitivity analysis. (See "Sensitivities" on page B-17.)

LNG Cost Comparisons

Table B-2 through Table B-6 details Hawai'i Gas forecasted costs and Hawaiian Electric forecasted costs, and compares the two.

Table B-2 itemizes the Hawai'i Gas forecasted costs for LNG for 0.6 mtpa, the associated capital expenditures (CapEx), and the combination of these two costs ("all-in") for both 2015 and nominal dollars.

$/MMBtu	Hawai'i Gas LNG 0.6 MTPA Price Forecasts					
	LNG 0.6 mtpa: 100% Henry Hub		CapEx Infrastructure: LNG 0.6 mtpa		All-In Cost: LNG 0.6 mtpa + CapEx Infrastructure	
Year	2015 Dollars	Nominal Dollars	2015 Dollars	Nominal Dollars	2015 Dollars	Nominal Dollars
2016	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a	n/a
2020	$10.98	$12.13	$1.83	$2.03	$12.81	$14.16
2021	$10.85	$12.27	$1.80	$2.04	$12.65	$14.31
2022	$10.87	$12.57	$1.77	$2.05	$12.64	$14.62
2023	$11.35	$13.38	$1.75	$2.06	$13.10	$15.44
2024	$11.67	$14.02	$1.72	$2.07	$13.39	$16.08
2025	$11.82	$14.47	$1.70	$2.08	$13.52	$16.54
2026	$11.65	$14.54	$1.67	$2.09	$13.32	$16.63
2027	$11.61	$14.78	$1.65	$2.10	$13.26	$16.88
2028	$11.67	$15.15	$1.63	$2.11	$13.30	$17.26
2029	$11.73	$15.54	$1.60	$2.12	$13.33	$17.66
2030	$11.74	$15.88	$1.58	$2.13	$13.32	$18.02
2031	$11.68	$16.15	$1.55	$2.15	$13.23	$18.29
2032	$11.71	$16.55	$1.53	$2.16	$13.24	$18.71
2033	$11.64	$16.81	$1.50	$2.17	$13.14	$18.99
2034	$11.62	$17.16	$1.48	$2.19	$13.10	$19.35
2035	$11.56	$17.46	$1.46	$2.20	$13.02	$19.66
2036	$11.55	$17.83	$1.44	$2.22	$12.99	$20.05
2037	$11.47	$18.10	$1.41	$2.23	$12.88	$20.33
2038	$11.40	$18.38	$1.39	$2.25	$12.79	$20.62
2039	$11.48	$18.91	$1.37	$2.26	$12.85	$21.18
2040	$11.49	$19.34	$1.35	$2.28	$12.85	$21.62
2041	$11.49	$19.73	$1.34	$2.29	$12.83	$22.02

Table B-2. Hawai'i Gas LNG 0.6 MTPA Price Forecasts

Like Table B-2, Table B-3 itemizes the Hawai'i Gas forecasted costs for LNG, except for 0.3 mtpa, the associated capital expenditures (CapEx), and the combination of these two costs ("all-in") for both 2015 and nominal dollars.

$/MMBtu	Hawai'i Gas LNG 0.3 MTPA Price Forecasts					
	LNG 0.3 mtpa: 100% Henry Hub		CapEx Infrastructure: LNG 0.3 mtpa		All-In Cost: LNG 0.3 mtpa + CapEx Infrastructure	
Year	2015 Dollars	Nominal Dollars	2015 Dollars	Nominal Dollars	2015 Dollars	Nominal Dollars
2016	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a	n/a
2020	$10.98	$12.13	$3.66	$4.04	$14.64	$16.17
2021	$10.85	$12.27	$3.59	$4.06	$14.44	$16.33
2022	$10.87	$12.57	$3.53	$4.09	$14.40	$16.65
2023	$11.35	$13.38	$3.48	$4.11	$14.83	$17.49
2024	$11.67	$14.02	$3.43	$4.12	$15.10	$18.14
2025	$11.82	$14.47	$3.39	$4.14	$15.21	$18.61
2026	$11.65	$14.54	$3.34	$4.17	$14.99	$18.71
2027	$11.61	$14.78	$3.29	$4.19	$14.90	$18.96
2028	$11.67	$15.15	$3.24	$4.21	$14.91	$19.36
2029	$11.73	$15.54	$3.19	$4.23	$14.92	$19.77
2030	$11.74	$15.88	$3.15	$4.26	$14.89	$20.14
2031	$11.68	$16.15	$3.10	$4.28	$14.78	$20.43
2032	$11.71	$16.55	$3.05	$4.31	$14.76	$20.86
2033	$11.64	$16.81	$3.00	$4.34	$14.64	$21.15
2034	$11.62	$17.16	$2.96	$4.36	$14.58	$21.53
2035	$11.56	$17.46	$2.91	$4.39	$14.47	$21.85
2036	$11.55	$17.83	$2.86	$4.42	$14.41	$22.25
2037	$11.47	$18.10	$2.82	$4.45	$14.29	$22.55
2038	$11.40	$18.38	$2.78	$4.48	$14.18	$22.86
2039	$11.48	$18.91	$2.74	$4.51	$14.22	$23.43
2040	$11.49	$19.34	$2.70	$4.54	$14.19	$23.88
2041	$11.49	$19.73	$2.66	$4.57	$14.16	$24.30

Table B-3. Hawai'i Gas LNG 0.3 MTPA Price Forecasts

Table B-4 itemizes the same information as Table B-2 and Table B-3, except for 0.9 mtpa. These four LNG-related tables all employ a 21-year planning horizon: 2020 to 2041.

$/MMBtu	Hawai'i Gas LNG 0.9 MTPA Price Forecasts					
	LNG 0.9 mtpa: 100% Henry Hub		CapEx Infrastructure: LNG 0.9 mtpa		All-In Cost: LNG 0.9 mtpa + CapEx Infrastructure	
Year	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*	*2015 Dollars*	*Nominal Dollars*
2016	n/a	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a	n/a
2020	$10.98	$12.13	$1.22	$1.35	$12.20	$13.48
2021	$10.85	$12.27	$1.20	$1.36	$12.05	$13.63
2022	$10.87	$12.57	$1.18	$1.37	$12.05	$13.93
2023	$11.35	$13.38	$1.16	$1.37	$12.51	$14.75
2024	$11.67	$14.02	$1.15	$1.38	$12.82	$15.39
2025	$11.82	$14.47	$1.13	$1.39	$12.95	$15.85
2026	$11.65	$14.54	$1.12	$1.39	$12.77	$15.93
2027	$11.61	$14.78	$1.10	$1.40	$12.71	$16.18
2028	$11.67	$15.15	$1.08	$1.41	$12.75	$16.56
2029	$11.73	$15.54	$1.07	$1.41	$12.80	$16.96
2030	$11.74	$15.88	$1.05	$1.42	$12.79	$17.30
2031	$11.68	$16.15	$1.04	$1.43	$12.72	$17.58
2032	$11.71	$16.55	$1.02	$1.44	$12.73	$17.99
2033	$11.64	$16.81	$1.00	$1.45	$12.64	$18.26
2034	$11.62	$17.16	$0.99	$1.46	$12.61	$18.62
2035	$11.56	$17.46	$0.97	$1.47	$12.53	$18.93
2036	$11.55	$17.83	$0.96	$1.48	$12.51	$19.31
2037	$11.47	$18.10	$0.94	$1.49	$12.41	$19.58
2038	$11.40	$18.38	$0.93	$1.50	$12.33	$19.88
2039	$11.48	$18.91	$0.92	$1.51	$12.40	$20.42
2040	$11.49	$19.34	$0.90	$1.52	$12.40	$20.86
2041	$11.49	$19.73	$0.89	$1.53	$12.38	$21.26

Table B-4. Hawai'i Gas LNG 0.9 MTPA Price Forecasts

Table B-5 itemizes the Hawaiian Electric forecasted costs for LNG and associated CapEx for nominal dollars, then compares the 0.6 mtpa all-in costs for Hawai'i Gas and Hawaiian Electric. Note that Hawaiian Electric's forecasted all-in costs begin to become the lower-cost option beginning in 2029.

$/MMBtu	Hawaiian Electric LNG Price Forecasts and Differentials				
	LNG: 2016 EIA Early Release	LNG: Total Cost Henry Hub	CapEx for New Infrastructure	All-In Cost: LNG + Infrastructure CapEx	All-In 0.6 mtpa Cost Differential: Hawai'i Gas – Hawaiian Electric
Year	*Nominal Dollars*	*Nominal Dollars*	*Nominal Dollars*	*Nominal Dollars*	*Nominal Dollars*
2016	n/a	n/a	n/a	n/a	n/a
2017	n/a	n/a	n/a	n/a	n/a
2018	n/a	n/a	n/a	n/a	n/a
2019	n/a	n/a	n/a	n/a	n/a
2020	n/a	n/a	n/a	n/a	n/a
2021	$7.61	$14.76	$0.90	$15.66	($1.35)
2022	$7.77	$15.01	$0.90	$15.91	($1.29)
2023	$8.03	$15.35	$0.90	$16.25	($0.81)
2024	$8.43	$15.83	$0.90	$16.73	($0.65)
2025	$8.71	$16.20	$0.90	$17.10	($0.56)
2026	$8.31	$15.88	$0.90	$16.78	($0.15)
2027	$8.43	$16.09	$0.90	$16.99	($0.11)
2028	$8.64	$16.39	$0.90	$17.29	($0.03)
2029	$8.85	$16.70	$0.90	$17.60	$0.06
2030	$9.03	$16.96	$0.90	$17.86	$0.16
2031	$9.15	$17.18	$0.90	$18.08	$0.21
2032	$9.36	$17.49	$0.90	$18.39	$0.32
2033	$9.48	$17.71	$0.90	$18.61	$0.38
2034	$9.64	$17.97	$0.90	$18.87	$0.48
2035	$9.78	$18.22	$0.90	$19.12	$0.54
2036	$9.96	$18.50	$0.90	$19.40	$0.65
2037	$10.07	$18.72	$0.90	$19.62	$0.71
2038	$10.19	$18.95	$0.90	$19.85	$0.77
2039	$10.49	$19.36	$0.90	$20.26	$0.92
2040	$10.71	$19.69	$0.90	$20.59	$1.03
2041	$10.94	$20.05	$0.90	$20.95	$1.07

Table B-5. Hawaiian Electric LNG Price Forecasts and Differentials

For the sake of comparison, Table B-6 itemizes the 2015 and nominal dollar costs for low sulfur fuel oil (LSFO), ultra-low sulfur diesel (ULSD), and a blend of 40% LSFO / 60% ULSD (for NAAQS compliance).

$/MMBtu	Hawaiian Electric Fuel Oil Price Forecasts					
	Low Sulfur Fuel Oil (LSFO)		Ultra-Low Sulfur Diesel (ULSD)		40% LSFO / 60% ULSD	
Year	Pacific Power (EIA) 2015 Dollars	Pacific Power (EIA) Nominal Dollars	2015 Dollars	Nominal Dollars	2015 Dollars	Nominal Dollars
2016	$9.14	$9.31	$11.95	$12.17	$10.26	$10.45
2017	$10.59	$11.01	$13.52	$14.06	$11.76	$12.23
2018	$11.90	$12.62	$15.36	$16.28	$13.28	$14.09
2019	$13.74	$14.86	$17.72	$19.16	$15.33	$16.58
2020	$14.70	$16.24	$18.92	$20.90	$16.39	$18.10
2021	$15.40	$17.42	$19.80	$22.39	$17.16	$19.41
2022	$15.96	$18.45	$20.43	$23.63	$17.75	$20.52
2023	$16.34	$19.26	$20.83	$24.55	$18.13	$21.38
2024	$16.65	$20.00	$21.18	$25.44	$18.47	$22.18
2025	$17.02	$20.83	$21.68	$26.53	$18.88	$23.11
2026	$17.48	$21.81	$22.23	$27.74	$19.38	$24.19
2027	$17.85	$22.72	$22.69	$28.88	$19.79	$25.18
2028	$18.12	$23.53	$23.05	$29.93	$20.09	$26.09
2029	$18.52	$24.54	$23.56	$31.21	$20.53	$27.21
2030	$18.79	$25.42	$23.90	$32.34	$20.83	$28.19
2031	$19.25	$26.62	$24.49	$33.86	$21.35	$29.51
2032	$19.73	$27.89	$25.12	$35.50	$21.89	$30.93
2033	$20.23	$29.22	$25.74	$37.18	$22.43	$32.40
2034	$20.77	$30.68	$26.44	$39.05	$23.04	$34.03
2035	$21.07	$31.82	$26.88	$40.60	$23.40	$35.33
2036	$21.58	$33.31	$27.54	$42.51	$23.96	$36.99
2037	$21.89	$34.53	$27.93	$44.06	$24.30	$38.34
2038	$22.42	$36.15	$28.61	$46.14	$24.90	$40.15
2039	$22.90	$37.73	$29.23	$48.16	$25.43	$41.90
2040	$23.45	$39.46	$29.95	$50.41	$26.05	$43.84
2041	$23.45	$40.25	$29.95	$51.42	$26.05	$44.71

Table B-6. Hawaiian Electric Fuel Price Forecasts

In the end, Hawai‘i Gas acknowledged that their costs were very similar to ours; thus, using our data as input would not materially affect the results of our modeling analysis. We also agreed on one main point: when compared to oil, LNG is cleaner burning and lower priced.

SunPower Input: Solar PV Potential

SunPower sent us a letter in response to our solicitation for input at our Second Stakeholder Conference. They also submitted a U.S. Department of Energy *SunShot Vision Study* (dated February 2012) that described the potential of PV in the greater United States together with PV system costs and forecasts (up to 2020) developed by GTM Research, a third-party industry research and analysis firm.

Among other topics, SunPower asserted that our resource assumptions for the costs and amounts of energy storage and PV were too high.

On May 31, 2016, we sent SunPower an email (copying all Parties) containing a series of questions about this input to garner more information. In that email, we stated that new resource cost assumptions are extremely important inputs to the PSIP analysis as they are major drivers for resource choices in our candidate resource plans. That email also contained seven questions requesting more information, to which they answered. SunPower responded on July 8, 2016.

Our emailed questions and SunPower's responses are reproduced here.

1. Are the GTM values expressed in real or nominal dollars? If expressed in real dollars, what is the reference year? If expressed in nominal dollars, what is the underlying rate of inflation assumed?

   SunPower Response: For the PSIP, we applied a 1.8% rate of inflation. These figures are all in 2016 dollars and do not account for inflation.

2. For the solar PV costs, we are assuming that the GTM costs are presented in dollars per DC watt. Please confirm. The High grid-scale solar and wind resource potential on O‘ahu PV costs presented in the PSIP are expressed in dollars per AC watt and assume fixed tilt systems with a 1.5 DC-to-AC inverter ratio. Thus, to get equivalent dollars per DC watt for High grid-scale solar and wind resource potential on O‘ahu solar, divide the PSIP numbers in Appendix J: Modeling Assumptions Data by 1.5. Please provide the MW AC size and DC-to-AC ratio assumed for the grid-scale solar. Please provide the DC-to-AC ratio assumed for the residential solar.

   SunPower Response: These figures are dollars per watt DC. For grid-scale solar, we assume a 1.3 DC-to-AC ratio and for residential we assume a 1.15 DC-to-AC ratio.

3. If you were designing a solar PV project for Hawai‘i, would you install fixed tilt or a tracking system? What inverter loading ratio would you use? (We understand that in actual application, this depends on the site and other factors, but we are interested in understanding what assumptions others believe we should be using in this regard in the PSIP projections).

SunPower Response: The answer to this question is site-specific. However, in our opinion, tracking systems provide increased solar production, which, in general, offsets the additional cost of the tracking system. Therefore, tracking systems typically provide a greater value than fixed tilt systems over the life of the PPA.

4. Have the GTM numbers been adjusted to reflect Hawai‘i costs? The PSIP solar PV numbers reflect premiums for Hawai‘i cost utilizing the RS Means Construction Index. The Hawai‘i location factors were applied to data obtained from IHS Energy. We also added 4% to the cost of the PV and wind systems to reflect Hawai‘i General Excise Taxes. The solar PV costs also reflect a land premium for Hawai‘i. The details of these cost factors as utilized in the PSIP numbers and how they were applied to adjust for just Hawai‘i were provided in response to PUC-HECO-IR-44.

   SunPower Response: SunPower utilizes a variety of competitive intelligence firms in our internal analysis, which include GTM as well as IHS and others. While the GTM numbers are not specific to Hawai‘i, we recommend the Companies utilize the GTM numbers (and associated forecast) as a baseline from which to extrapolate a Hawai‘i PV cost forecast, utilizing the Companies’ detailed cost information from recent PUC-approved PV PPAs. From our perspective, it is important work from the GTM numbers utilizing a broad base of recent PV PPAs in Hawai‘i in order to reflect forecasted “real world” PV costs.

5. Similarly, have the storage numbers been adjusted for just Hawai‘i? They do say “Hawai‘i” so we assume so. Please confirm.

   SunPower Response: Yes, the storage numbers we provided are adjusted for just Hawai‘i. We also encourage the Companies to obtain access to the Bloomberg New Energy Finance New Energy Outlook 2016 as an additional resource. The report includes storage cost forecasts (which, for reference, are lower than the storage numbers we provided) from 2015–2040.

6. Can you provide the numbers that are in the storage cost graphs in a tabular format (preferably in Microsoft Excel or similar?)

   SunPower Response: The graph represents SunPower’s internal analysis for storage costs for Hawai‘i, utilizing a variety of sources, some of which are proprietary or confidential. SunPower felt comfortable with sharing the results of our internal analysis in the spirit of collaboration. However, we are not comfortable providing associated spreadsheets.

7. What cost trend (in real terms if possible) would you recommend using for solar PV after 2020?

   SunPower Response: It is rare to find a cost trend for PV post-2020. However, given recent history, it is certainly expected that costs will continue to decline. The most

> recent cost trend information we have access to is the Bloomberg New Energy Finance New Energy Outlook 2016, which includes cost trend assumptions for PV out to 2040. As you may know, access to that report requires a subscription and we encourage the Companies to obtain access to it. We also suggest that the Companies reach out to GTM and the Department of Energy SunShot Initiative to seek their guidance.

Before responding to our questions, SunPower asked if we both could meet to discuss the assumptions related to grid-scale solar PV and energy storage capital costs, and other forecasts. Over the subsequent months, together we engaged in a number of very constructive conversations about this information. Topics centered around the capital costs of grid-scale PV (both fixed tilt and single-axis tracking), commercial and residential PV, and energy storage projections and forecasts.

Because of their specific and objective information, we reinvestigated our solar PV and energy storage capital costs assumptions. SunPower's PV and storage capital cost assumptions were only forecasted through 2020 for the greater United States, without any cost adjustments or extrapolations being made for the state of Hawai'i. SunPower's projections (actually, those of GTM Research) were quite a bit lower than our PSIP assumptions.

Nonetheless, we compared SunPower's grid-scale and residential PV and battery energy storage system (BESS) forecasts to the PSIP assumptions, with adjustments made to ensure that the assumptions were being compared on a consistent basis. We found their cost assumptions to be relatively close to ours: SunPower's grid-scale PV costs were marginally lower, with their residential PV and BESS marginally higher.

Thus, we determined there is no objective nor defensible basis for changing our solar PV capital cost assumptions. To initially develop our assumptions, we informally vetted them with a project developer and found them to be generally consistent with the market price (that is, approximately $4 per DC watt installed). In fact, the many data points we investigated suggested that, if anything, our solar PV capital cost forecasts were too low. We informed SunPower of our conclusions, and pointed out that their indicative EPC-only price for West Loch was about the same as our projection.

SunPower suggested that we should use a single-axis tracker in our assumptions rather than fixed tilt, even though existing grid-scale PV projects are about evenly split between the two systems.

SunPower considered our energy storage cost assumptions to be too low, yet on further examination, they exhibit only minor differences. SunPower did point out that a two-hour residential BESS—not the four-hour residential BESS in our assumptions—is typical in today's market. SunPower also pointed out our BESS assumptions are not set for economies of scale—in other words, the prices for a 1 MW BESS models are the same as a 10 MW BESS. We have made these adjustments to our assumptions. SunPower suggested that we model multiple capabilities—load shifting, renewable firming, reactive power, frequency response, and black start capabilities—for longer-duration batteries. They also consider a grid-scale PV plus BESS worthy of analysis.

SunPower recommended that we should delineate between residential and commercial PV systems by developing separate forecasts. Our cost assumption uses one price for both residential and commercial PV, which we consider reasonable for our long-term modeling analysis. Still, in the future, we will develop separate price forecasts: one for commercial PV and one for residential PV (which we've noted in Chapter 7: Next Steps).

Finally, SunPower indicated that limiting development of grid-scale PV on land slopes less than 5% was conservative and 10% was more aggressive, but was not able to comment if there would be an added cost for such development. Our analysis, as a result of input from Ulupono and Blue Planet representative Dr. Matthias Fripp, considers grid-scale PV development on land slopes up to 10%.

During our wide ranging and lengthy discussions, we both have jointly identified and discussed the factors that may explain the differences between GTM Research's numbers and our PSIP assumptions. In the end, however, these discussions have not resulted in us changing our grid-scale PV and storage capital cost assumptions. Discussions with SunPower made clear that we developed these PSIP assumptions as fairly and as objectively as possible, to which they concurred.

Paniolo Power Input: Pumped Storage Hydro and Grid-Scale Wind

Over the course of 2016, the Companies have repeatedly and earnestly tried to engage and work with Paniolo Power regarding input assumptions related to pumped storage hydroelectricity and grid-scale wind. While Paniolo Power provided their data to us (some was protected under a development agreement, was thus proprietary, and could not be divulged), some of it was outdated, some was only slightly different than ours, and some was identical to ours. As a result, we were unable to use their data in our modeling analyses.

In February 2016, Paniolo Power submitted a 25-page report, *Study of Pumped Storage Hydroelectric for the Island of Hawai'i* (published with a February 11, 2016 date), prepared by Siemens. In a February 18, 2016 email to Paniolo, the Companies acknowledged receipt of that report. On that same day, HD Baker & Company emailed Paniolo requesting information about the report, citing specific capital costs for pumped storage hydro obtained informally from Eurus at the First Technical Conference on January 7, 2016.

On March 7, 2016, the Companies sent a detailed "informal data request" to Paniolo Power requesting information for modeling Parker Ranch's suggested pumped storage hydro project. On March 22, 2016, Paniolo Power sent its responses, and also filed its responses in Docket No. 2014-0183. Their response, however, did not include detailed information requested for modeling in PSS/E (a Siemens software product) that would allow us to evaluate the resource for transmission planning and system security modeling. Further, Paniolo's response did not provide certain information regarding ramp rates in MW per minute (as requested) so that we could evaluate the Paniolo-suggested wind project on a sub-hourly basis.

In addition, Paniolo did not provide prices, instead only providing indicative costs. (In production simulations, costs cannot be substituted for prices, as prices include gross profit and more accurately represent the total capital investment assumptions.) Neither did Paniolo provide detailed annual dispatch simulation results nor a summary of the input assumptions used in the Siemens report. Paniolo asserted that pumped storage hydro could provide ancillary services and contribute to system reliability, yet they provided no information to support that assertion. Paniolo didn't provide all the information needed to evaluate PSH.

We contacted Paniolo with follow-up questions to obtain the additional necessary information. Paniolo stated that such information could not be provided because they risked disclosing proprietary and competitive information. As a result, we could not incorporate this incomplete Paniolo Power information in our modeling analyses.

On September 14, 2016, Paniolo Power filed its first set of questions in response to Order No. 33877 together with a 106–page slide deck report entitled *Hawai'i Island Generation Supply Transformation Plan*, submitted by Siemens 16 months earlier on May 14, 2015—even though, in that interim period, both the Commission (through Order No. 33320 and Order No. 33740) and the Companies (through filed plans and three stakeholder conferences) repeatedly requested input from the Parties. Five days later at Technical Conference #1, Commission consultant Carl Freedman asked if we had reviewed the report (which he termed "well done") or attempted to "replicate" the results.

We subsequently were able to review Paniolo's filed report. We discovered that the report's results were based on 2014 PSIP assumptions, making it virtually impossible to benchmark and compare these results to our 2016 PSIP analysis. (At the Fourth Stakeholder Meeting, Party members, including Paniolo, acknowledged that such a benchmarking effort was unproductive.) The report neglected to provide a complete set of input assumptions or detailed results of its system dispatch modeling, making it impossible to scrutinize the results.

On September 28, 2016, again in response to Order No. 33740, Paniolo filed its second set of questions, plus two additional Siemens reports: *Study of Electric Supply Options for the*

Island of Hawai'i (published with a July 2015 date, 16 pages, and essentially a narrative summary of the 106-page slide deck report) and *Study of Pumped Storage Hydroelectric for the Island of Hawai'i* (previously given to us).

Within days of that filing, we assembled a spreadsheet comparing our input assumptions for our current modeling analysis, comparing them to the same information provided by Paniolo (specifically, the *Hawai'i Island Generation Supply Transformation Plan* report and their responses to our February informal data request). The spreadsheet revealed a number of gaps in Paniolo's data. At the Fourth Stakeholder Meeting, Paniolo reviewed this spreadsheet, finally providing the missing information. In an October 22, 2016 email, Paniolo changed some of this information and added more details.

Here is our summary evaluation of their information:

1. Paniolo based their reports on outdated 2014 EIA AEO prices, where oil prices were double today's prices. Their use of the 2014 PSIP assumptions attempted to benchmark their analysis with the 2014 PSIP Preferred Plan for Hawai'i Island. Paniolo acknowledged the difficulty in making a side-by-side comparison between of the 2016 PSIP analyses and the 2014-based Siemens analysis.
2. Paniolo did not consider ramp rates (they didn't conduct any sub-hourly analysis). However, they confirmed that our 20% per minute ramp rate was consistent with the technology.
3. Paniolo's assumptions were only slightly different for factors such as forced and planned outage rates, fixed O&M costs, and other factors (see Table B-7).

Pumped Storage Hydro Factor and Rate Assumptions		
Factor and Rate	*Hawaiian Electric*	*Paniolo Power*
AFUDC Factor	16.36%	Presumably accounted for in annual fixed charge
Levelized Cost Factor	11.43%	Presumably accounted for in annual fixed charge
Fixed Charge Per Year	$44.16 per kW month (2020 calculated)	$43.99 per kW month
Duration Hours	6.0 hours	6.0 hours
Turnaround Efficiency (net)	80%	85%
Discharge Cycles Per Year	365	Up to 365, drawn when needed
Depth of Discharge	100%	Up to 100%, no limit
Plant Life	40 years	40 years
Construction Years	6 years	5 years
Spin Ramp Rate	20% per second	20% (equivalent to HELCO unit ramp rates)
Quick Start Ramp Rate	20% per second	20% (equivalent to HELCO unit ramp rates)
Fixed O&M	$30 per kW year	$28 per kW year
Forced Outage Rate	3.00%	2.00%
Planned Outage Rate	3.80%	5.00%

Table B-7. Pumped Storage Hydro Factor and Rate Assumptions

4. We assume a turnaround efficiency rate for pumped storage hydro of 80%; Paniolo's uses an efficiency rate of 85% (see Table B-7). At the Fourth Stakeholder Meeting, Paniolo could not verify that their assumed 85% turnaround efficiency was net round-trip or it was the technology efficiency before accounting for auxiliary station loads and losses. A Ternary pumped storage hydro design (mentioned in the Siemens report), which switches between pumping and generation in less than a minute, might be able to achieve net efficiency rates greater than 80%. However, this is untested.

   In response to our query about the difference in efficiency ratings, Paniolo acknowledged (in an email sent November 3, 2016) that, based on head, flow, technology, and design, an 85% turnaround efficiency could be achieved. However, because Siemens did not indicate a specific design for the pumped storage hydro "project" discussed in their report, Paniolo acknowledged that we should use an 80% turnaround efficiency in our 2016 PSIP modeling.

Nominal $/kW	Pumped Storage Hydro Overnight Capital Cost Assumptions	
Year	*Hawaiian Electric*	*Paniolo Power*
2016	$3,500	Mauna Kea Sites: $4,000 to $4,500 per kW Kohala Sites: $5,000 to $6,000 per kW Reference year 2013, escalator not specified
2017	$3,563	
2018	$3,627	
2019	$3,692	
2020	$3,759	
2021	$3,827	
2022	$3,895	
2023	$3,966	
2024	$4,037	
2025	$4,110	
2026	$4,184	
2027	$4,259	
2028	$4,336	
2029	$4,414	
2030	$4,493	
2031	$4,574	
2032	$4,656	
2033	$4,740	
2034	$4,825	
2035	$4,912	
2036	$5,001	
2037	$5,091	
2038	$5,182	
2039	$5,276	
2040	$5,370	
2041	$5,467	
2042	$5,566	
2043	$5,666	
2044	$5,768	
2045	$5,872	

Table B-8. Pumped Storage Hydro Overnight Capital Cost Assumptions

5. Paniolo's capital cost assumptions for pumped storage hydro were higher than our 2016 PSIP assumptions (see Table B-8). At the Fourth Stakeholder Meeting, Paniolo asked that we not use their site-specific pumped storage capital costs, but rather use our lower non-site-specific capital cost estimate.

6. Paniolo's stated grid-scale wind factors and rate assumptions, with some caveats, are identical to our 2016 PSIP assumptions (Table B-9).

Grid-Scale Wind Factor and Rate Assumptions		
Factor and Rate	*Hawaiian Electric*	*Paniolo Power*
Wind Plant Size	30 MW	20, 40, 60, & 80 MW
Wind Plant Capital Cost	$2,465 per kW	$2,338 per kW*
Total Development and Construction Time	2 years	2 years
Fixed O&M	$33.79 per kW year	$33.79 per kW year†
Annual Capacity Factor	54%	54%
Unitized 8,760 Annual Hour Wind Profile	Based on Tawhiri historical data	Based on Tawhiri historical data

* Assumes wind development in 2019; cost assumption from Table B-10.
† Based on 2014 PSIP assumptions. Fixed operations and maintenance costs would be closer to the Hawaiian Electric 2016 PSIP assumption.

Table B-9. Grid-Scale Wind Factor and Rate Assumptions

7. In the same November 3, 2016 email (mentioned above), Paniolo told us that they had retained AWS Truepower to analyze Paniolo's wind data. This analyzed wind data, however, would not be available until approximately December 1, 2016, but stated that Paniolo would attempt to get the results sooner. Paniolo did offer to provide us with the AWS Truepower modeled wind as an estimate for site-specific wind in "a day or two". In our response, we stated that December 1, 2016 was much too late for us to consider their wind analysis results in our modeling, but that the estimated wind data would "work for us". Paniolo provided these site-specific wind estimates on November 11, 2016, which we passed along to E3. We told Paniolo that, if there was time after modeling the current queue of work, we would use these wind estimates in our analysis, but it was unlikely. Fortunately, E3 was able to incorporate the November 11, 2016 information into the sensitivity analysis.

   Paniolo subsequently emailed us the completed AWS Truepower report on December 5, 2016. The report summarized a 55.9% net capacity factor for wind sited on Parker Ranch. Paniolo stated that they would analyze three years of actual wind data using smaller and fewer wind turbines sited in the most optimal locations; as a result, they expected the net capacity factor to increase. The report redacted the proposed site layout and location pending community knowledge and acceptance. We informed Paniolo that E3 was nearly complete with their analytical work and would not be able to incorporate this information.

   Table B-10 compares the wind plant cost assumptions—declining in real dollars over time—for Paniolo Power and the Companies. Paniolo sourced their cost assumptions from Berkeley Lab, Electricity Markets & Policy Group Summary Brief of October

2016; our cost assumptions were developed for us by NextEra Energy. Paniolo Power referenced our wind capital cost assumptions when applying Berkeley Lab's declining cost assumptions. (Note that Paniolo Power has cited NextEra Energy Resources as a current development partner.)

2016 Real $/kW	Wind Plant Capital Cost Assumption Comparison		
Year	*Hawaiian Electric Companies*	*Paniolo Power*	*% Difference*
2014	n/a	$2,550	n/a
2015	n/a	$2,508	n/a
2016	$2,465	$2,465	0.00%
2017	$2,459	$2,423	+1.49%
2018	$2,357	$2,380	–1.00%
2019	$2,301	$2,338	–1.61%
2020	$2,309	$2,295	+0.61%
2021	$2,305	$2,259	+2.04%
2022	$2,324	$2,224	+4.50%
2023	$2,334	$2,188	+6.67%
2024	$2,333	$2,152	+8.41%
2025	$2,318	$2,117	+9.49%
2026	$2,303	$2,081	+10.67%
2027	$2,279	$2,045	+11.44%
2028	$2,264	$2,009	+12.69%
2029	$2,244	$1,974	+13.68%
2030	$2,234	$1,938	+15.27%
2031	$2,212	$1,924	+14.97%
2032	$2,199	$1,910	+15.13%
2033	$2,178	$1,896	+14.87%
2034	$2,165	$1,882	+15.04%
2035	$2,144	$1,868	+14.78%
2036	$2,131	$1,854	+14.94%
2037	$2,112	$1,840	+14.78%
2038	$2,099	$1,826	+14.95%
2039	$2,079	$1,812	+14.74%
2040	$2,067	$1,798	+14.96%
2041	$2,048	$1,784	+14.80%
2042	$2,035	$1,770	+14.97%
2043	$2,017	$1,756	+14.86%
2044	$2,005	$1,742	+15.10%
2045	$1,986	$1,728	+14.93%

Table B-10. Wind Plant Overnight Capital Cost Assumptions

8. While Paniolo states that "[a]ccelerating bulk LNG delivery by 3 years and lowering LNG prices can produce significant cost savings in the near to medium term when LNG consumption is the highest,"[33] they fail to provide any supporting evidence for this claim.

9. Paniolo's plan states "Lower Rooftop Solar Penetration Results in Reduced Curtailment"[34] as a heading to a slide. It's unclear from this headline if they are recommending less rooftop PV or attempting to justify that curtailment. Paniolo states "PV penetration rates for HI are based on HELCO PSIP forecasts"[35] and assume no curtailment of DG-PV.

10. It's unclear if Paniolo's plan addresses regulation or system security requirements.

As an interesting note to analyzing pumped storage hydro as a viable energy storage method, during our Fourth Stakeholder Meeting, Dr. Fripp stated that his SWITCH optimization model for O'ahu chose BESS over pumped storage hydro because BESS costs decline over time whereas pumped storage hydro cost remain relatively flat.

The bottom line: For pumped storage hydro, Paniolo ultimately provided outdated, materially similar, and mostly identical information as our PSIP assumptions. In the end, we used our 2016 PSH cost assumptions (which were also lower than Paniolo's) for our modeling analyses. In addition, their estimated wind data was provided too late for us to use as inputs to our modeling process. We can, however, incorporate such input submitted on a timely bases in future updated.

Additional Party Input

Two other technologies were raised by the Parties: load banks during our Third Stakeholder Conference, and ocean energy technologies outside of the official proceeding.

Load Banks

The Alliance for Solar Choice (TASC), at the Third Stakeholder Conference, suggested that the Companies begin analyzing distributed load banks and modeling potential locations (beginning with Moloka'i because of its small size) as a means to consume otherwise curtailed renewable energy. TASC cited a similar installation employing two 1.5 MW systems on Tasmania by way of example. TASC did not provide costs for load banks, nor did they provide a functioning grid-scale example.

[33] Docket No. 2014-0183, *Paniolo Power Company, LLC's First Round of Questions Pursuant to Order No. 33877*, filed September 14, 2016, at 21 (page 10 of Attachment 1).

[34] *Ibid.*, at 38 (page 27 of Attachment 1).

[35] *Ibid.*, at 66 (page 55 of Attachment 1).

E3's analysis currently uses varying methods for handling curtailed renewable energy (such as energy storage and demand response) and identifies the most economical resource mix. Although load banks may have value to mitigate contingency events, absent additional information about how load banks could improve on our analysis and potentially reduce costs, we did not consider load banks in our resource assumptions.

Ocean Energy Technologies

After our Third Stakeholder Conference, Life of the Land referenced a U.S. Department of Energy study asserting that O‘ahu could be fully powered with ocean energy technologies. The study was actually published by EPRI in 2011 with a companion report published in 2004.[36] The 2011 report, *Mapping and Assessment of the United States ocean Wave Energy Resource*[37] maps ocean areas that are potential sites for ocean energy technology and theoretically asserts the ocean energy potential of coastline United States, Hawai‘i of course being at the forefront. It doesn't, however, discuss the current potential or related costs of such technology.

For that, we referred to the Technology Readiness Level (TRL) and Commercial Readiness Index (CRI) for hydrokinetic energy: ocean wave, tidal generation, and ocean thermal energy conversion (OTEC). According to our 2014 PSIPs, the CRI for ocean wave and tidal generation is 3-commercial scale-up: implementation by specific policy because financing is not available; the CRI for OTEC is 2-commercial trial, meaning a commercial trial whose funding is 100% at risk. According to Dr. Luis Vega, University of Hawai‘i, in a 2014 presentation,[38] ocean wave and tidal generation is premature and whose devices will not be available for one to two decades; OTEC needs approximately five to ten years to build a commercially viable 10 MW unit where the cost would be about 50¢ per kWh.

For more information about ocean (hydrokinetic) energy technologies, see "Hydrokinetic Energy" in Appendix H: Renewable Resource Options for O‘ahu. Our modeling analysis did not consider ocean energy technologies because of its latent nature, uncertain viability, and exorbitant costs.

Sensitivities Input

In our stakeholder meetings and subsequent conference calls, certain Parties (most notably Ulupono, Paniolo Power, the Consumer Advocate, DBEDT, Hawai‘i Gas) and the Companies discussed and developed a series of sensitivities to run. These sensitivities included the hedge premium for fossil fuels, fuel price risk, and O‘ahu-based DOD projects. The results of these sensitivities are described in Chapter 3: Analytical Approach.

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[36] Available at http://www.energy.ca.gov/oceanenergy/E2I_EPRI_REPORT_WAVE_ENERGY.PDF.

[37] Available at http://www1.eere.energy.gov/water/pdfs/mappingandassessment.pdf.

[38] Ocean Thermal Energy Conversion (OTEC) & Wave Energy Conversion (WEC) for Pacific Island Nations & Asian Developing Nations (http://www.boem.gov/NREL-OTEC-WEC/), July 30, 2014; p 27–28.

FIRST STAKEHOLDER CONFERENCE: DECEMBER 17, 2015

On Thursday, December 17, 2015, we convened a three-hour stakeholder conference. Colton Ching , Hawaiian Electric Vice President of Energy Delivery, introduced the conference; Mark Glick, DBEDT Energy Administrator, moderated and facilitated the conference.

Our goals for the stakeholder conference were two-fold:

- *Overall Objective:* To obtain a clearer understanding of potential input from the Parties and how it might affect how we develop the 2016 updated PSIPs.
- *Process Considerations:* Discuss the objectives of the process set forth by the Commission in Order No. 33320, answer specific questions regarding the PSIP analysis process, and discuss any other pertinent issues raised by the stakeholders.

We invited over 40 people, including representatives from all Parties and the Commission, to attend the conference and to give a presentation about their input. Here is the first of two email messages we sent to invitees.

> Sent: Wednesday, December 09, 2015 9:54 AM
>
> Subject: PSIP Stakeholder Conference - December 17, 1pm-4pm
>
> Aloha,
>
> We would like to invite you to attend Hawaiian Electric's Power Supply Improvement Plan (PSIP) Stakeholder Conference.
>
> This Conference is intended to be an open discussion of the PSIP update process. The Conference will consist of a series of moderated open discussions around the following objectives:
>
> A. Respond to questions and accept comments that parties may have about the Companies' November 25th filing, providing its plan for updating the PSIP.
>
> B. Seek input from meeting participants on future pricing for resource options, including but not limited to grid scale generation (renewable and fossil), DER, DR, and grid modernization components. Input to include pricing and ability of these options to provide grid or ancillary services.
>
> C. Seek input from meeting participants on developable levels of various renewable resource options, including but not limited to grid scale wind, grid scale solar, distributed solar, geothermal, etc.
>
> In order to maintain a neutral position, the Department of Business, Economic Development and Tourism has agreed to moderate these discussions. The conversations that take place at this

Conference are intended to be informal and not part of the official record in this docket. This is to encourage open and constructive dialogue. Accordingly, we ask that no recording devices of any kind (video or audio) be used. Your acceptance of this invitation indicates your acceptance of these conditions. We thank you for your cooperation.

The Conference will take place on Thursday, December 17, from 1:00 PM until 4:00 PM, in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu. Parking validation will not be provided for this event. A government issued ID is required for entry into this building. Please arrive early to allow time for check in (present your ID and receive a Visitor badge).

Due to space limitations, we would appreciate it if you could select one person to represent your organization at this Conference. While we strongly encourage in-person participation, a limited number of conference lines will be available for remote access to the meeting.

If your organization wishes to attend this meeting, please RSVP no later than noon, Tuesday, December 15, 2015 and indicate who will be representing your organization at this meeting. If you plan to call into this meeting, please also indicate that in your RSVP response.

RSVP to:
Heather Villamil
(808) 543-5820

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

Two days later, we sent the following email to provide more details about the conference.

Sent: Friday, December 11, 2015 8:50 PM

Subject: Additional Info: PSIP Stakeholder Conference - December 17, 1pm-4pm

Aloha,

We are reaching out to you with some additional logistics on the Hawaiian Electric's Power Supply Improvement Plan (PSIP) Stakeholder Conference scheduled for December 17, 2015.

If you wish to provide input in the form of a formal presentation at this meeting, that opportunity will be offered to you. In order to allow everyone an opportunity to participate in the meeting, we would ask that you keep your formal presentation brief (7-10 minutes) and that you adhere to the agenda topics outlined below:

• Resource options, including but not limited to grid-scale generation (renewable and fossil), DER, DR, and grid modernization components. Input to include pricing and ability of these options to provide grid or ancillary services.

• Developable levels of various renewable resource options, including but not limited to grid-scale wind, grid-scale solar, distributed solar, geothermal, etc.

We are particularly interested in your thoughts regarding the resource options we should consider in the PSIP updates. This includes technologies, cost trends, their utilization as a grid resource and constraints by island, if any. If you plan to use slides or other visuals for your presentation, please send the electronic version BY NOON, TUESDAY, DECEMBER 15, 2015 to the email address below. By Monday, we will send a presentation template for your convenience. This opportunity to present is optional, i.e. there is no requirement that you prepare a presentation. The number of presentations will be limited to the time allotted for this meeting and presentation requests will be honored in the order that we receive the presentations via email. If you wish to distribute hard copies to the stakeholders, please bring at least 30 copies.

REMINDER: The Conference will take place on Thursday, December 17, from 1:00 PM to 4:00 PM, in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu.

We have received several requests for permission to allow more than one representative to attend the stakeholder conference. After reconsideration, although space remains limited, we will do our best to accommodate two representatives per organization to attend in person. In addition, as stated previously, we will also allow for participation via telephone conference. Unfortunately, the conference bridge also has limits, and for that reason, we will need to reserve remote access for only those who do not have a representative attending in person. We thank you for your understanding. AS A REMINDER: If your organization wishes to attend this meeting, please RSVP no later than NOON, TUESDAY, DECEMBER 15, 2015 to Heather Villamil. Her contact information is below. PLEASE INDICATE WHO WILL BE REPRESENTING YOUR ORGANIZATION. IF YOU ARE UNABLE TO ATTEND IN PERSON, PLEASE INFORM US IF YOU WILL BE PARTICIPATING VIA TELEPHONE CONFERENCE AND THE NAME OF THE INDIVIDUALWHO WILL BE CALLING IN

RSVP to:
Heather Villamil
(808) 543-5820
heather.villamil@hawaiianelectric.com

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

Conference Proceedings: First Stakeholder Conference

About 40 people (excluding company personnel) attended either in person or through a phone-in bridge. As we recommended, the meeting was fairly informal to better solicit candid remarks.

Colton Ching opened the meeting, discussed the purpose of the conference, and outlined the four milestones for the April 2016 PSIP update. Mark Glick used a presentation format to organize and conduct the conference (see page B-130 for the slides). During the presentation, Mr. Glick focused on garnering input regarding the Commission's eight Observations and Concerns. He also explained that the Companies were seeking comments regarding the inputs, assumptions, analysis, and results for the updated PSIPs.

The conference featured three presentations from the Parties. Mr. Yunker presented DBEDT's planning methodology to achieve an energy future that meets or exceeds the state's energy goals (see page B-150 for the slides). Erik Kvam of REACH presented its recommendations for a process to develop a mix of resource options for attaining 100% renewable generation (see page B-154 for the slides). Matthias Fripp, professor at the University of Hawaiʻi and a consultant to Blue Planet Foundation and Ulupono, presented how a SWITCH Optimization Model can be employed to develop the resource option necessary for achieving 100% renewable power on Oʻahu (see page B-159 for the slides).

Following the presentation, Mr. Glick and Mr. Ching opened the floor for input and questions from the Parties. A lively discussion ensued regarding the many aspects that comprise the development of the updated PSIPs.

ORDER NO. 33320: PARTY INPUT AND OUR RESPONSE

Order No. 33320 directed the Parties in the docket to file a report on January 15, 2016 that included, among other topics, input to our process for creating the 2016 updated PSIPs. (The Order stated that the term "Parties" in this docket refers "collectively to the Parties, Intervenors, and Participants in this proceeding."[39]) Our *Proposed PSIP Revision Plan* stated that:

> The Companies welcome and actively seek to obtain input from the Parties and other stakeholders regarding the assumptions, methods, and evaluation metrics. … (T)he Companies encourage the Parties to provide constructive inputs related to the Commission's Observations and Concerns, supplemented with appropriate quantitative justification, methodology, assumptions, and information sources that can apply to the creation of actionable updated PSIPs. This input can be particularly impactful to our analyses. The Companies will incorporate input submitted by the Parties to the extent that time allows.[40]

To assist the Parties, our *Proposed PSIP Revision Plan* contained a table[41] describing, in detail, the high priority inputs to the Commission's eight Observations and Concerns that we require for our analysis.

How We Considered and Incorporated Input from the Parties

We reviewed each Party's filing in detail and organized their input into 15 topics. We then decided how to incorporate the topic into our analysis, and when we would be performing this analysis by assigning each topic a timing status:

- Out of scope. We recognize the Commission's specific instructions to limit issues in the April 2016 updated PSIP to the issues established by the Commission. (Order No. 33320 specifically states that the Parties' "participation will be limited to the issues as established by the commission in this docket.")[42]
- Addressed or incorporated in the *PSIP Update Interim Status Report*.
- Addressed or incorporated in our April 2016 updated PSIP.

[39] Order No. 33320; *op. cit.* at 171.

[40] Docket 2014-0183, *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, *op. cit.* at 28–29.

[41] Docket 2014-0183, *Hawaiian Electric Companies' Proposed PSIP Revision Plan*, *op. cit.*, Table 1. High Priority Input Required for our Analysis, at 29–31.

[42] Order No. 33320; *op. cit.* at 171.

- Addressed in our resource planning that continued after the April 2016 updated PSIP was filed.

To date, we have incorporated several key points of feedback from the Parties in our 2016 updated PSIP. We:

- Distributed resource cost assumptions to the Parties on February 2, 2016 to provide transparency of input variable assumptions and provide an opportunity for Parties comments on these input variables.
- Established an FTP site where input information and data developed thus far in the PSIP updated process is posted. This allows the Parties to access information and post feedback. We established this communication platform to provide transparency and a greater understanding of the input variables to be used for the PSIP Update analysis.
- Used a Decision Framework to establish a clear basis for how plan objectives will be prioritized and to clarify how Preferred Plans are selected among the candidate plans.
- Introduced the PSIP optimization processes consisting of DER, DR, and grid-scale iterative cycles to capture analytical steps in achieving our 100% RPS goals which ensure planning iterations are performed to meet the optimization objectives across these resource options.
- Invited Party representatives to participate in working meetings with the Hawaiian Electric Companies' planning team on the remainder of analysis and modeling for the April 2016 updated PSIP. This creates greater transparency of the planning, analysis, process, and decisions made during the iterative process.

Receiving Party Input

In their January 15, 2016 filing and again during the March 8, 2016 technical conference, many Parties offered opinions and suggestions regarding resource types to consider. We were unable to find any specific numerical or objective data in Party input that could be used in our 2016 PSIP modeling efforts. We did, however, consider and address the resource types suggested by the Parties. In addition, two Parties included in their filings specific cost information regarding projects they are sponsoring. We compared and validated this cost input to other independent data sources, resulting in certain resource capital cost assumptions reflecting Party input.

Input Incorporated from Other Organizations

Our *Proposed PSIP Revision Plan* listed six additional organizations whose data and independent technical analyses could help address issues of concern for the April 2016 updated PSIP. These stakeholders include the Hawai'i Natural Energy Institute (HNEI), Electric Power Research Institute (EPRI), U.S. Department of Energy, University of Hawai'i Economic Research Organization (UHERO), National Renewable Energy Laboratory (NREL), and Hawai'i Energy.

NREL has performed an independent review of our new resource assumptions and an independent analysis of the wind and solar PV "developable" potential for each island. EPRI provided access to their database for developing resource costs. In addition, EPRI submitted their report on the impact of wind and solar on regulation reserve requirements. HNEI and an additional stakeholder, General Electric, provided input on regulating reserve requirements.

Hawai'i Energy provided us with energy efficiency projections by reducing energy intensities on current square footage, assisting us in developing long-term forecasts that would support the PSIP.

In addition, we contacted Pulama Lana'i about their plans related to projected energy use and possible self-generation for us to include in our analysis. In their February 9, 2016 response letter, Pulama Lana'i stated they are continuing to investigate multiple energy options, but that they were not at a point to contribute any input.

Responding to Order No. 33320 Party Input

We have read every filing submitted by the stakeholders, assimilated the comments, and determined how best to incorporate them into our analysis and in our process for creating the updated PSIP. To streamline our response, we organized the input comments into 15 topics. Table B-11 contains a cross reference between a Party filing and the 15 topics. A checkmark indicates that a Party commented on that topic; a dash means that they did not comment on the topic. The remainder of this section explains each topic and our response.

Party	1. Business Model	2. Value of Solar	3. Decision Framework	4. Transparency	5. Resource Inputs	6. Cases and Sensitivities	7. System Security	8. DER & DR Optimization	9. Risks	10. Customer Bill Impacts	11. LNG	12. Fossil Generation	13. Party Input	14. EE and EV	15. Interisland Transmission
CoH	√	–	–	√	√	–	–	–	–	√	–	–	–	–	–
CoM	√	–	√	√	√	√	–	√	√	√	–	–	–	–	√
DBEDT	–	–	√	√	√	√	–	√	√	√	–	√	√	√	–
DCA	–	–	–	√	√	√	√	√	√	√	√	√	√	√	√
AES	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Blue Planet	√	–	√	√	√	√	–	–	√	–	√	–	–	√	–
DERC	√	√	√	√	√	–	√	√	√	–	–	–	–	–	–
Eurus	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hawaiʻi Gas	–	–	–	√	√	√	–	–	√	–	√	√	–	–	–
HPVC*	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
HREA	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
HSEA*	√	–	–	–	√	√	–	√	√	–	√	–	√	√	–
LOL	√	–	–	√	√	–	√	√	–	√	–	–	√	–	–
NextEra	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Paniolo Power	√	–	√	√	√	√	–	–	√	√	√	√	–	–	√
Puna Pono	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
REACH	–	–	√	√	√	√	√	–	√	–	–	–	–	√	–
Sierra Club	√	–	–	–	√	–	–	√	–	–	√	√	–	–	–
SunEdison	–	√	–	–	–	–	–	√	–	√	–	√	–	–	–
SunPower	–	√	√	√	–	–	–	√	–	√	√	√	–	–	–
TASC	√	√	√	√	√	–	√	√	–	–	–	–	–	–	–
Tawhiri	–	–	–	–	–	–	–	√	–	√	–	√	√	–	–
Ulupono	√	–	–	√	–	–	–	√	√	√	√	–	–	–	√

* = Joinder to Sierra Club's submission

Table B-11. Party to Order No. 33320 Input Topic Cross Reference

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

1. Utility Business Model

Some Parties assert that the Companies need to transform their business model to move forward and enable the new Hawai‘i energy landscape. The Commission stated this topic in its Inclinations, but not in Order No. 33320.

Our Action Regarding this Topic

A business model discussion would include at least these three key criteria:

- What is the optimal design and operation of Hawai‘i's electric system in the future to achieve Hawai‘i's energy goals? Our action plans will answer a significant part of this question.
- What is the optimal role of the Companies in this future?
- How are the Companies situated to carry out this role?

While we concur that our business model is an important issue to discuss, as directed by the Commission, continued discussion is beyond the scope of this docket.

We developed our action plans within the framework of a sustainable business model that enables us to transform our power grid to meet the 100% renewable energy goal.

Incorporated in that business model is our intent to remain one of several owners and operators of grid-scale generation.

2. Value of Solar

The Parties assert that our avoided cost methodology does not fully capture the value of solar, and recommend a comprehensive study to develop a different methodology.

Our Action Regarding this Topic

For our April 2016 PSIP update, we were confident that our avoided cost methodology and the development of integration solutions and costs and characteristics of operation is a sufficient proxy given the time constraints.

We directly addressed this for our December 2016 PSIP update. E3's work compares the total resource costs of available resources and determines the most the economical resource plan. The total resource cost of DG-PV (specific amounts are listed in Appendix J: Modeling Assumptions Data) is significantly higher than that of grid-scale PV. To account for the value and actual cost of energy produced by DG-PV, E3 performed analyses incorporating both the High-DER and the Market-DER forecasts as assumed inputs.

3. Optimization Decision Framework

The Parties stated that our process for choosing the Preferred Plans in our 2014 PSIPs was not well articulated and was flawed; that the optimization steps were unclear; and that our discrete uncoordinated analysis resulted in suboptimal resource allocation. Some Parties concluded that the process needs an optimization framework detailing an overarching logic; and that this framework guide development paths and portfolios for specific goals (for example, rate reduction, low cost, and 100% RPS), and help select Preferred Plans that best accomplish those goals.

Our Action Regarding this Topic

For our December 2016 PSIP update, we modified our analytical approach, relying on an automated process involving an analytical flow of three modeling tools: RESOLVE, PowerSimm Planner, and PLEXOS (fully explained in Chapter 3: Analytical Approach).

4. Transparency

The Parties want to understand and be informed about:

- How the analysis models work and interact with each other.
- How the assumptions were created and which assumptions were used.
- How the methodologies were developed.
- How decisions are made.
- How discrepancies are resolved.

Our Action Regarding this Topic

We documented our input assumptions and process in Chapter 3: Analytical Approach; all input assumptions in Appendix J: Modeling Assumptions Data; and descriptions of all modeling tools in Appendix C: Analysis Methods and Models.

We established an FTP (WebDAV) server site where we post content from our PSIP work; the server enables the Parties not only to read this content, but also to post additional content and to comment. To further our desire to make our process transparent, we invited representatives from the Intervenors to attend our planning and decision-making meetings; three organizations responded: the Consumer Advocate, DBEDT, the County of Maui, and the County of Hawaiʻi. These representatives attended many of our weekly planning meetings, both in person and through a phone bridge.

5. Resource Inputs

The Parties want assurance that all resource assumptions are reasonable and well grounded, such as:

- What is the actual amount of land available for wind resources on Maui?
- What is the most likely trajectory for fuel costs over the next 20 years?
- What are the most accurate assumption for capital costs for renewable resources?

Our Action Regarding this Topic

Appendix J: Modeling Assumptions Data documents how we arrived at the assumptions used in our analyses. We have uploaded all resource assumptions to the FTP (WebDAV) server. We also requested additional information from Paniolo Power about the initial resource inputs they provided. For our December 2016 updated PSIP, we engaged with SunPower in productive discussions regarding solar PV and BESS costs, and have completed the sensitivity analyses using input assumptions from the Parties.

6. Cases and Sensitivities

The Parties want various cases and sensitivities explored, such as:

- A least-cost case serving as a reference case (even if the case is not 100% RPS).
- Every alternative plan to document the value of incremental spending compared to the least-cost case.
- A sensitivity analysis of the system requirements for various levels.

Our Action Regarding this Topic

In addition to developing our post-April PSIP plans, E3 developed multiple core cases and sensitivities using input from the Parties.

7. System Security Criteria

The Parties contend that the system security methodology and results published in our 2014 PSIPs are overly conservative and limit DER adoption; and that system-level constraints should emphasize safety, reliability, and power quality rather than economics.

Our Action Regarding this Topic

We are using the analyses from the *Integrated Demand Response Portfolio Plan* (IDRPP) supplemental filing to determine technology-neutral system security requirements for each resource plan. This included removing any system must run requirements for each island's grid as a starting point for system security analysis. If the technical requirements are met, DR and DER can be used to support, impact, and provide system security.

Appendix O: System Security Analysis documents the process and results from our system security analysis.

8. DER and DR Optimization

The Parties want assurance that the PSIP is coordinated with the DER and DR dockets; that we treat DER as a resource to be optimized (and not an end state); and that appropriate consideration be given to motivate customer adoption. The Parties want us to view DER as customer-centric solutions and recommend our conducting an in-depth study to better achieve the Commission's overarching goals for reducing rates and ensuring a clean energy future while providing customer choice.

Our Action Regarding this Topic

We documented our current DER and DR optimization process, and have explained the potential services that DER and DR can provide to the grid and how we plan to fully utilize them. (Refer to Appendix C: Analysis Methods and Models.) We also considered the benefits of incorporating the High-DER forecast, which is a non-market based approach that attempts to estimate the potential of DG-PV.

We will provide information about the tariff structure and implementation in the DER and DR dockets.

9. Risks

The Parties want assurance that all risks are properly documented and explored through the various portfolios and options. They are concerned that customers will bear the impact of stranded costs because of the chosen resource mix, and want information on when and how customer savings are realized under the various plans.

Our Action Regarding this Topic

The objective was to determine "least-regrets" near-term action plans. Results from the analyses and sensitivities were considered in determining the "least-regrets" near-term action plans.

10. Customer Bill Impacts and Relevant Metrics

Some of the Parties want assurance that the impact on customer bills will be evaluated for all plans, that nominal impacts will be stated for all plans, and that comparisons with alternative portfolios will be provided. Some Parties want the Companies to develop bill impact estimates for various residential segments (such as customers who do and do not participate in distributed generation programs).

Our Action Regarding this Topic

Chapter 5: Financial Impacts compares the impact on customer bills in both nominal and real dollars.

11. Liquefied Natural Gas (LNG)

The Parties want us to specify our plan to import and exit from LNG use, to minimize or eliminate stranded costs that impact customers; and to see the savings demonstrated for using LNG as a bridge fuel as compared to investing in only renewable generation. Some parties do not consider LNG a feasible option because it's not a renewable resource.

Our Action Regarding this Topic

As indicated in our Motion for Clarification[43] and our PSIP Work Plan,[44] LNG is not included in the near-term action plan. We have, however, analyzed and included these analyses with LNG over the long-term in the December 2016 PSIP update to determine LNG's impact in stabilizing and lowering costs for customers and in lowering emissions while aiding in the effective integration of more renewable energy.

12. Fossil Generation Upgrades

The Parties want to better understand the final cost and performance characteristics of fossil generation upgrades (such as, how the units previously performed, what the modified units are now capable of, and how the performance and savings of the modified generators might compare to new and existing generating units).

Our Action Regarding this Topic

As indicated in our Motion for Clarification and our PSIP Work Plan, the 3x1 Kahe combined cycle project has been removed from the near-term action plan. The post-April PSIP plan and cases evaluated by E3 compare different resource plans with and without generation modernization. Ascend Analytics also analyzed the benefits of replacing dispatchable generation with flexible generation.

13. Party Input

The Parties want assurance that their input will be considered and integrated in candidate plans and in the Preferred Plans.

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[43] *Hawaiian Electric Companies' Motion for Clarification of Order No. 33877; op. cit.*

[44] *PSIP Update Revised Analytical Approach and Work Plan; op. cit.*

Our Action Regarding this Topic

This appendix describes, in detail, how we considered and incorporated party input into our analyses. Virtually all input dealt with process; we received virtually no data that directly contributed to our analyses.

14. Energy Efficiency and Electric Vehicles

Some Parties want to know how energy efficiency help grid issues. The CA wants us to incorporate measures from recently published energy efficiency studies into our analyses. The Parties want us to encourage further adoption of electric transportation.

Our Action Regarding this Topic

We incorporated energy efficiency measures that meet EEPS into our analyses. We offer TOU incentives to EV owners to shift charging to overnight, and are piloting a charging infrastructure that can align with DR programs and pricing. We have filed a revised TOU structure to shift charging to midday when solar production is at its peak.

To minimize "range anxiety", we are installing and operating publicly available, direct current fast charging stations that can charge an EV battery to 80% capacity in 30 minutes. We are also demonstrating the capability to limit and curtail the maximum demand of a 50 kW DC fast charging station to 25 kW, and investigating opportunities to encourage daytime public and workplace charging.

Hawaiian Electric participates in the Honolulu Department of Transportation Services (DTS) 2016 Transportation Investment Generating Economic Recovery (TIGER) grant application for a Honolulu Urban Bus Circulator System. The TIGER grant is a cost-effective solution to significantly advance mobility in the most congested areas of the city. The current proposal includes up to 24 high frequency and high capacity electric buses that will be incorporated within the circulator system; Hawaiian Electric plans to partner with DTS on the electric bus charging infrastructure.

15. Interisland Transmission

The Parties want us to address the impact of interisland transmission on the reliability of the O‘ahu, Maui, and Hawai‘i Island power grids, specifically how a forced cable outage affects reserve requirements and reliability.

Our Action Regarding this Topic

E3 has completed the "copper-plate" analysis which assumes O‘ahu, Maui, and Hawai‘i are grid-connected in 2020 to understand whether interisland transmission is cost-effective under the most optimistic conditions. Further analyses is needed to understand the impacts of a forced cable outage.

SECOND STAKEHOLDER CONFERENCE: MAY 17, 2016

In our *PSIP Update Report: April 2016*, we proposed to convene a Second Stakeholder Conference on April 15, 2016. During that conference, we were to:

> …present and discuss the supplemented, amended, and updated set of PSIP conclusions, recommendations, Preferred Plans, and their complementary five-year action plans. In addition, we plan to present and discuss the analyses and results from addressing the Commission's eight Observations and Concerns, and discuss both the near-term and long-term customer rates and bill impacts.[45]

To better prepare for that meeting, and to ensure E3's involvement, we decided to postpone the conference until a date uncertain. To wit, we sent the following email to the Parties, other stakeholders, and the Commission.

> Sent: Friday, April 08, 2016 8:43 AM
>
> Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference
>
> Aloha,
>
> We would like to inform you that the Hawaiian Electric Companies' proposed April 15, 2016 Technical Conference will be rescheduled to a later date as a Stakeholder Conference. We are currently working on the logistics for the Stakeholder Conference and will advise you of the date, time, and location once the details have been worked out. Thank you for your patience.
>
> Mahalo,
> Todd Kanja
>
> PSIP Project Lead

After deciding on a place, date, and time, we sent the following email to the Parties, other stakeholders, and the Commission.

> Sent: Wednesday, May 04, 2016 5:47 PM
>
> Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference
>
> Aloha,
>
> Please be advised that the Hawaiian Electric Companies will hold a PSIP Update Stakeholder Conference on Tuesday, May 17, 2016 from 9 am–11:30 am, at the American Savings Bank tower, 1101 Bishop St, 8th Floor, Honolulu, Hawai'i, 96813. Additional details, along with a meeting agenda, for the conference will follow.
>
> Mahalo
> Todd Kanja
> PSIP Project Lead

[45] *PSIP Update Report: April 2016*, at B-6.

A week later, we emailed the Parties, other stakeholders, and the Commission to officially invite them, and to present the format and structure of the conference.

Sent: Wednesday, May 11, 2016 4:14 PM

Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference - May 17, 2016

Aloha,

We would like to invite you to attend Hawaiian Electric's second Power Supply Improvement Plan (PSIP) Stakeholder Conference.

This Conference is intended to be an open discussion of the Next Steps and forward-going PSIP planning work. In particular input on the scenarios and analytical structure/process to assess unfinished planning work will be timely. The Conference will consist of a series of moderated discussions around the following topics:

A. PSIP Update Highlights and Next Steps

B. Presentation by EThree Consulting on Capacity Expansion Modeling

C. Comments and Questions & Answers

The Department of Business, Economic Development and Tourism has agreed to moderate these discussions. The conversations that take place at this Conference are intended to be informal and not part of the official record in this docket. This is to encourage open and constructive dialogue. Accordingly, we ask that no recording devices of any kind (video or audio) be used. Your acceptance of this invitation indicates your acceptance of these conditions. We thank you for your cooperation.

The Conference will take place on Tuesday, May 17, from 9:00 AM to 11:30 AM, on the 8th Floor of the American Savings Bank Tower located at 1001 Bishop St., Honolulu, HI 96813 in downtown Honolulu. Parking validation will not be provided for this event.

We would appreciate it if you could select one person to represent your organization at this Conference. A limited number of conference lines will be available for remote access to the meeting. If your organization wishes to attend or participate via conference call, please RSVP no later than noon, Friday, May 13, 2016 and indicate who will be representing your organization at this meeting. If you plan to call into this meeting, please also indicate that in your RSVP response.

RSVP to:
Heather Villamil
(808) 543-5820
heather.villamil@hawaiianelectric.com

We look forward to seeing you at this meeting.

Mahalo,
Colton Ching

To better ensure the greatest participation from the Parties and other stakeholders, we emailed them again with this reminder about accepting our invitation.

> Sent: Monday, May 16, 2016 9:17 AM
>
> Subject: Hawaiian Electric Companies' PSIP Stakeholder Conference - May 17, 2016
>
> Good morning,
>
> Thank you to those of you that have already sent in your RSVPs for tomorrow's Stakeholder Conference. For those that have not submitted your RSVP yet, we would appreciate it if you could do so by noon today to Heather Villamil:
>
> Heather Villamil
> (808) 543-5820
> heather.villamil@hawaiianelectric.com
>
> We look forward to seeing you at this meeting.
>
> Aloha,
> Todd

On May 17, 2016, we convened the Second Stakeholder Conference. Although the meeting was scheduled for two-and-a-half-hours, the actual meeting ran three hours. See "Conference Proceedings: Second Stakeholder Conference" on page B-64 for a summary.

On the day following the conference, we sent the following email to summarize the conference and to solicit additional input from the stakeholders.

> Sent: Wednesday, May 18, 2016 7:14 AM
>
> Subject: PSIP Stakeholder Conference - Thank You
>
> Good morning,
>
> Thank you for participating in yesterday's Stakeholder Conference! We sincerely value each opportunity we have to engage in thoughtful discussion with all of you, along with the sharing of ideas and inputs for further consideration in the PSIP update process. We would especially like to thank Mark Glick for facilitating the group's discussion once again and Ren Orans and Ana Mileva from E3 for their detailed presentation on their use of the RESOLVE model. For your information and reference, attached are copies of the slides that were presented.
>
> We continue to welcome any additional ideas, inputs or comments that you may have. Please don't hesitate to send them to Todd Kanja, Hawaiian Electric's Project Lead for the PSIP Update. Todd can be reached at: todd.kanja@hawaiianelectric.com and (808) 543-4329. To allow adequate time for assessment as part of our current analyses, we would appreciate receiving your information by Wednesday, May 31, 2016.
>
> Mahalo!
> Colton Ching

As of Friday, May 27, 2016, we had received input from only two of the Parties, so we sent the following reminder email.

> Sent: Friday, May 27, 2016 4:56 PM
>
> Subject: PSIP Stakeholder Conference - Thank You
>
> Aloha,
>
> Just sending a friendly reminder that we would appreciate any additional ideas, inputs or comments that you may have by Tuesday, May 31, 2016. Hope you all have an enjoyable Memorial Day weekend!
>
> Mahalo,
> Todd

Conference Proceedings: Second Stakeholder Conference

Alan Oshima, President of the Hawaiian Electric Companies, opened the conference by saying that the PSIP is a 30-year journey to attain our 100% renewable energy goal; that the Companies cannot do it alone; that public policy must align; and that while we are all aligned on this goal, we are here in collaboration to determine how best to reach that goal.

Colton Ching, Vice President of Energy Delivery at the Hawaiian Electric Companies, introduced the meeting, explained its guidelines, and discussed how the Companies' analysis must keep up with new inputs, assumptions, and changes in public policy. Mr. Ching then highlighted the contents of the *PSIP Update Report: April 2016*, and explained our efforts for greater transparency. Topics included resource assumptions, the decision framework, themes and cases, renewable energy on O'ahu, interisland transmission, DER, DR, 100% renewable energy versus 100% RPS, and LNG combined with generation modernization.

Next steps include investigating further offshore wind, optimizing DR and DER, update our production simulations, conducting a risk premium analysis of oil and LNG, integrating the updated EIA fuel price forecasts, investigating interisland transmission for bring benefits and renewable generation to connected islands, and further analysis around system security.

Mr. Glick introduced Ren Orans and Ana Mileva from E3 who presented their RESOLVE capacity expansion model (see page B-166 for the slides). E3's is an independent planning effort using a different methodology and approach to determine how their conclusions compare with those of the Companies' analysis. Mr. Orans and Ms. Mileva explained how a diverse renewable portfolio enables them to be able to adjust as certain technologies emerge or change in their 'potency' and cost. They explained three options:

overbuild renewables, pursue integration solutions to avoid overbuilding, or determine the optimal mix of solutions and overbuilding. For their continued work, they requested input around the scope, costs, and benefits of interisland transmission beyond the analysis already underway; concepts of how interisland transmission fits into the five island resource plans; and also input for offshore wind—all as elements of attaining 100% renewable generation on Oʻahu.

Mr. Glick encouraged attendees to focus their questions around the Next Steps in the *PSIP Update Report: April 2016*. Colton clarified that comments should focus on creating an updated plan, and that near-term steps will not be taken until approved by the PUC and after long-term direction is clarified. Most questions centered on assumptions and constraints incorporated into the plans, and that they be re-evaluated, especially the assumption that Oʻahu cannot produce all its energy needs from renewables.

Input Received: Second Stakeholder Conference

By our stated deadline of May 31, 2016, we received input from nine sources, two of which were letters signed by a group of the Parties. Here is an overview of the submitted input, almost all of which the Parties also submitted in response to Order No. 33740.

Ulupono, et al. A group letter signed by Ulupono, Blue Planet, Sierra Club, Hawaiʻi Gas, County of Maui, HREA, and DERC of Hawaiʻi. Ulupono submitted this exact letter in its response to Order No. 33740. For a summary of this Ulupono filing Order No. 33740, see "Ulupono et al Joint Recommendations—Multiple Signers" on page B-68 and "Ulupono Initiative Comments" on page B-70.

Hawaiʻi Gas. An email requesting that the Companies use in future modeling, the LNG price forecasts from the Hawaiʻi Gas binding RFP and contract negotiations. The email listed Hawaiʻi Gas's price forecasts using EIA AEO and STEO price forecast and escalation methods to enable a comparison on an "apples to apples" basis. Hawaiʻi Gas essentially filed this same information (although using slightly different wording) in its response to Order No. 33740. For a summary of this Hawaiʻi Gas Order No. 33740 filing, see "Hawaiʻi Gas Comments" on page B-73.)

County of Hawaiʻi. A letter stating the lack of meaningful stakeholder engagement, the dearth of opportunities for stakeholder participation, and the lack of transparency in model assumptions and data input during the Companies' process of developing the PSIP Update. The County of Hawaiʻi also called for a second conference "to allow for greater collaboration and increased dialog between" the Companies and stakeholders. The County of Hawaiʻi filed their letter in Docket No. 2014-0183 on June 1, 2016, and also filed additional comments in response to Order No. 33740. For a summary of the County of Hawaiʻi Order No. 33740 filing, see "County of Hawaiʻi Comments" on page B-82.

TASC. Sunrun sent an email on behalf of The Alliance for Solar Choice. This email appears as Exhibit A in the joint Hawai'i PV Coalition and TASC filing in response to Order No. 33740. For a summary of the joint HPVC and TASC Order No. 33740 filing, see "Hawai'i PV Coalition (HPVC) and The Alliance for Solar Choice (TASC) Comments" on page B-79.

AES Hawai'i. An emailed letter discussing the future of the AES Kapolei facility as outlined in the PSIP Update. AES included and expanded on this discussion in its response to Order No. 33740. For a summary of the AES Order No. 33740 filing, see "AES Hawai'i Comments" on page B-85.

SunPower. An email stating that the energy storage and PV cost assumptions in the PSIP Update are significantly higher that current market conditions, and proposing lower energy storage costs for subsequent analysis. SunPower filed these same comments and data in its response to Order No. 33740. For a summary of the SunPower Order No. 33740 filing, see "SunPower Comments" on page B-76.

REACH. An email with an attached 23-page report entitled *Creating the Electric Utility We Want…in Hawai'i or Anywhere*. REACH filed this same report in its response to Order No. 33740. For a summary of the REACH Order No. 33740 filing, see "Renewable Action Coalition of Hawai'i (REACH) Comments" on page B-81.

Blue Planet, et al. A group-emailed letter signed by Blue Planet, Sierra Club, Paniolo Power, DERC of Hawai'i, HREA, HSEA, and the County of Maui. The signers stated their support of the Ulupono et al. letter. The signers questioned whether or not the collaboration between the Companies and stakeholders was meaningful as evidenced by the Companies' recent LNG filings which "is prematurely seeking to implement the centerpiece of its proposed PSIP and…its proposed merger with NextEra Energy". The signers called for an immediate withdrawal of the applications filed in Docket No. 2016-0135: LNG Application, Docket No. 2016-0136: Kahe Combined Cycle Waiver from Competitive Bidding, and Docket No. 2016-0137: Kahe Combined Cycle 3x1 Generating Unit. (*Note:* The Companies withdrew all three applications following the Commission's dismissal without prejudice of Docket No. 2015-0022: Change of Control.)

Blue Planet did not file this letter in Docket No. 2014-0183 in response to Order No. 33740; its three pages are reproduced starting on page B-163.

Blue Planet also filed wholly different comments in response to Order No. 33740. For a summary of the Blue Planet Order No. 33740 filing, see "Blue Planet Foundation Comments" on page B-72.

ORDER NO. 33740: SUMMARIES OF FILED RESPONSES

On June 3, 2016, the Commission issued Order No. 33740 inviting comments from the Parties and from the general public on the *PSIP Update Report: April 2016*, Docket No. 2014-0183, and Order No. 33320. Specifically, the Commission requested comments on its Initial Statement of Issues "for the review, supplement, amendment, and updating of the PSIPs for each of the Companies.

1. Whether the PSIPs, as amended and updated in this proceeding, provide useful context and meaningful analysis to inform major resource acquisition and system operation decisions and identify well-reasoned and adequately-supported plans and actions that will result in reliable energy services, meeting State clean energy requirements, while ensuring that costs and rates will be reasonable.
2. Whether the PSIP for each of the HECO Companies, as amended and updated in this proceeding, includes reasonable plan components as required for HECO in Order No. 32053, including:
   a. A Fossil Generation Retirement Plan;
   b. A Generation Flexibility Plan;
   c. A Must-Run Generation Reduction Plan;
   d. An Environmental Compliance Plan;
   e. A Key Generator Utilization Plan;
   f. An Optimal Renewable Energy Portfolio Plan; and
   g. A Generation Commitment and Economic Dispatch Review.
3. Whether the PSIPs, as amended and updated, adequately address the Observations and Concerns addressed in this Order."[46]
   1. The PSIP cost impacts and risks have not been demonstrated to be reasonable.
   2. The PSIPs do not appear to aggressively seek lower-cost, new grid-scale renewable resources.
   3. The PSIPs utilization do not adequately address and integration of distributed energy resources.
   4. The proposed plans for fossil-fueled power plants are not sufficiently justified.

[46] Order No. 33320; *op. cit.* at 138–139.

5. System security requirements appear costly and are not sufficiently justified.
6. The proposed plan for provision of ancillary services lacks transparency and may not be most cost-effective option.
7. The PSIP analysis on interisland transmission lacks sufficient detail.
8. Customer and implementation risks are not adequately addressed.[47]

Twenty of the 23 Parties (NextEra, Eurus, and First Wind did not file responses), the Companies, and 174 members of the general public filed responses to the Order.

This section contains summaries of each Party response, a summary of the general public responses, and a summary of the Companies' response. This section begins with the Ulupono et all summary, as it was signed by eleven of the Parties, is followed by the responses of these signers (as they are all somewhat related), continues with the remaining Party responses (in the order in which they were filed) and a summary of the general public comments, and concludes with the Companies' response.

To focus on the most pertinent information, comments related to the proceeding's background have been omitted. All pertinent comments are numbered to better itemize and refer to them, cross referenced to specific pages within each filing.

Summaries of the Ulupono et al Filing and Its Party Signers

Ulupono et al Joint Recommendations—Multiple Signers

Eleven of the Parties submitted a Joint Recommendations filing on June 17, 2016. The filing contained two sections:

- Joint Recommendations signed by Ulupono, Blue Planet, Hawai‘i Gas, County of Maui, HREA, Sierra Club, DERC of Hawai‘i, HSEA, SunPower, TASC, and HPVC. These signers feel that the PSIP Update raises numerous concerns and needs further work, which were articulated in the letter attached as Annex A.
- An Annex A that contained the jointly-signed letter sent to the Companies on May 31, 2016 as solicited input following the Second Stakeholder Conference. This letter was signed by Ulupono, Blue Planet, Hawai‘i Gas, County of Maui, HREA, Sierra Club, DERC of Hawai‘i, and Paniolo Power.

All signers of the joint recommendations and the Annex A letter (except HREA and HSEA) filed additional comments highlighting specific concerns in response to Order No. 33740.

[47] Order No. 33320; *op. cit.* at 3–7.

Ulupono et al Joint Recommendations. Here is a summary of the joint recommendations of the near-term steps that the Commission should consider "to ensure constructive further progress in this docket" (p 1). (As a matter of clarity, the numbers and letters of this summary coincide with the same numbers and letters in the Ulupono et al Joint Recommendations filing.) The Commission should:

1. Convene a second stakeholder session as soon as possible to focus on specific concerns and feedback from the Parties (p 2).
2. Clarify and reaffirms the PSIP objectives, and provide guidance as to how the PSIP must address elements required by Order No. 33320 (p 2).
3. Convene one or more technical sessions to review modeling and assumptions used by RESOLVE, indicate how SWITCH can supplement and improve RESOLVE, and ensure that RESOLVE is used transparently (p 3). RESOLVE should identify:
   a. Three to five alternative generation resource mixes to attain 100% clean energy by 2045 and an action plan for each alternative for the next 5 years (p 3).

b. Identify key decisions the Commission must make to implement each alternative action plan (p 3).

c. Identify key factors that the Commission should use to evaluate each plan to ultimately select the desired action plan (p 3).

Invite the Parties to submit limited numbers of information requests (as part of the docket record) before a technical sessions to be answered by the Companies at the technical session or after to be answered within two weeks (p 4).

4. Appoint an Independent Entity to oversee the work of finalizing the PSIP (p 4).
5. Ensure the Companies finalize the PSIP based on all Party input and comments in a manner that ensures transparency (p 4).
6. Direct the Companies to present a draft PSIP to all Parties for review and comments to be submitted within four weeks (p 5).
7. Direct the Companies to incorporate Party comments and file the PSIP in the docket (p 5).
8. Request the Parties to submit a brief recommending a PSIP preferred plan and its near term action steps (p 5).
9. Decide which PSIP preferred plan to accept for each operating utility (p 5).
10. Establish dates for formal review of the status and progress made by each operating utility on its preferred plan (p 5).

Ulupono el al Annex A Letter. The Ulupono et al Annex A Letter begins with a request to convene another stakeholder conference (which the Companies held on June 29, 2016). The remainder of the Annex A letter is summarized here.

1. While the E3 RESOLVE model is focused, transparent, objective, and understandable, it should be adjusted to:
   a. Be free of artificial constraints or biases and its assumptions corrected or supplemented, such as assuming that Oʻahu cannot achieve 100% renewable generation on its own (Annex A, pp 1–2).
   b. Include a more comprehensive analysis of the volatility of oil and LNG prices using market-based prices and relying on Monte Carlo, block bootstrap methods, and other probabilistic analytic approaches (Annex A, p 2).
   c. Include a "base" or "reference" plan for comparing cases (Annex A, pp 1–2).
   d. Use the aforementioned adjustments to create cases for the underlying modeling and analysis in developing the PSIP (Annex A, p 2).
2. The PSIP analysis should be expanded to integrate more DG-PV and microgrids, and to consider the implications of customer retention economics (Annex A, pp 2–3).
3. The PSIP should be expanded to include updated battery storage information and emerging and expanded DER approaches, methodologies, and devices (Annex A, p 2).
4. The PSIP should analyze a statewide grid through a comprehensive or selective interisland two-way cable system with various site-specific offshore and onshore resource options (Annex A, p 2).
5. The PSIP analysis should be expanded so that its conclusions more fully embrace the Commission's *Inclinations*, and the RESOLVE model enhanced as previously discussed to produce results that would help to identify, frame, and provide realistic policy choices and embody real and substantial stakeholder participation and input (Annex A, p 3).
6. The Companies should collaborate more closely with stakeholders, especially considering independent their studies and analyses (Annex A, p 4).

Ulupono Initiative Comments

Ulupono Initiative also filed individual comments in response to Order No. 33740. Ulupono's filing contained three sections: their own comments, the complete Joint Recommendations filing, and an Annex B that contained three slides from a presentation that was to be given by Matthias Fripp at the stakeholder conference yet to be held on

June 29, 2016. This summary focuses only on the first section of Ulupono's own comments.

1. The essential need of the PSIP process—unbiased, objective analysis and information—has not been met and that the tremendous amount of information and insight generated by the Companies has not been correctly integrated into the evolving PSIP (p 2).

2. The PSIP Update introduced new systemic biases and failed to correct methodological errors. Ulupono previously highlighted such that the full set of viable resource options, nor the tradeoffs between them, have been fully disclosed beyond nominal direct cost comparisons (p 3).

3. The analytical process employed to develop the PSIP Update (defining and evaluating three themes) not only is inferior to the capacity expansion planning approach, but also produced artificially constrained choices (point 1, pp 3–4).

4. The PSIP Update, in a flawed and deceptive manner, uses the EIA's short-term (13–24 month) energy outlook (STEO) price forecast in a long-term price scenario, with artificially low future price escalations that are entirely the construct of the Companies (point 2, p 4).

5. The PSIP Update ignores the impacts of fossil fuel price volatility and its incumbent risks, which should be evaluated, explicitly quantified, and assessed with the real asset hedge offered by renewable energy resources. There are three viable, quantitative approaches to incorporating the costs of volatility: 1. Actual market quotes regarding hedging costs from qualified companies; 2. Mathematical algorithms for estimating hedging costs; and 3. Use a Monte Carlo approach to evaluate choices over a long timeframe (point 3, pp 4–6).

6. Near-term resource choice is not based on objective and unbiased analysis, as evidenced by eliminating the SunEdison and Hu Honua projects, including Department of Defense resource projects, and refusing to consider sourcing LNG through a collaboration with Hawai‘i Gas (point 4, pp 6–7).

7. The PSIP Update is entirely utility ownership centric, relying heavily in a misguided and unsubstantiated attempt to create value in NextEra's acquisition of the Companies as necessary to achieve the preferred plans. The Companies, as stand-alone entities, are completely capable of securing long-term LNG contracts and of building combined cycle units (point 5, p 7).

8. While demonstrating considerable work, the PSIP Update does not adequately address the underlying purpose and ultimate function (p 8), only partially follows

the guidance and mandates required by the Commission (p 9), and does not provide what the Initial Statement of Issues requires in at least three specific areas:

- **a.** The PSIP Update and its concomitant five-year action plans, like the 2014 PSIPs before, are predicated on a predefined end state and incomplete analysis; then substantiated through faulty, inadequate, and otherwise incomplete and misleading "choices" (point 1, pp 9–10)
- **b.** The rationale for developing customer bill impacts is not explained or justified, especially when comparing the 23% reduction in monthly bills for full service residential customers (declared in the 2014 PSIPs) with the slight increase stated in the PSIP Update, despite using STEO energy price forecasts which are artificially low (point 2, p 10).
- **c.** The means for financing, nor the total financial implications on customers, of the substantial projected capital expenditures required for each theme is not fully and realistically examined (point 3, pp 10–11).

9. The most constructive approach to developing a PSIP that meets its intended use—to provide unbiased, objective information regarding the tradeoffs to ratepayers of alternative resource portfolios—is for the Commission, the Consumer Advocate, the Parties, and the Companies to jointly undertake this task (pp 11–12).

Blue Planet Foundation Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), Blue Planet filed the following comments in response to Order No. 33740. Those comments, summarized here, are in additional to the input Blue Planet supplied in response to the Companies' solicitation following the Second Stakeholder Conference.

1. The PSIP Update suffers systemic deficiencies, some likely related to biased assumptions of utility ownership, energy asset ownership, and an evolving business model that are either a reflection of or the cause of planning biases (pp 1–2).
2. Distributed energy resources are treated as exogenous factors (that is, forecast) instead of a resource to be maximized, discounting the fact that customer update of DER can be greatly influenced (both positively and negatively) by utility action strategies (p 2).
3. Planned quantified risk analysis should not only include LNG versus oil, but also on new fossil fuel and renewable generation and DER to properly assess and value all generation options, as well as to understand how grid reliability and security risks affect this same range of generation options (p 3).

4. Any new investments in fossil fuel infrastructure should be limited to system needs only after optimizing the foundational elements of a 100% renewable system (pp 3–4).

5. Certain energy storage options—pumped storage hydro, hydrogen storage, distributed energy storage systems, and thermal distributed storage—must be more thoroughly considered with a certain level of vision, even if that vision includes a measure of uncertainty (pp 4–5).

6. The disparity between installing offshore wind resources until after 2030 must be reconciled with the Bureau of Ocean Energy Management's (BOEM) having already started the process for leasing offshore wind sites (p 5).

7. The different conclusions derived from the SWITCH and RESOLVE capacity expansion models must be studied to determine the cause of their divergent results (pp 5–6).

Hawai'i Gas Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), Hawai'i Gas filed comments in response to Order No. 33740. Those comments, summarized here, include the input Hawai'i Gas supplied in response to the Companies' solicitation following the Second Stakeholder Conference.

1. The Companies chose not to incorporate Hawai'i Gas's lower-cost LNG pricing in either its PSIP Update nor in its LNG application, even though that pricing would have saved customers an additional $3.5 billion over 20 years (p 1).

2. Provided in its comments, Hawai'i Gas included:
   - An overview of the infrastructure costs associated with the Hawai'i Gas logistics model which included the floating storage regasification unit (FSRU) submerged turret loading (STL) system, undersea pipeline, and onshore facilities (pp 2–3).
   - A description of the Hawai'i Gas LNG logistics model for receiving, regasifying, and distributing LNG on O'ahu (pp 3–5).
   - An explanation of the permitting and scheduling process (pp 5–6).
   - A detailed summary of the total delivered LNG Brent prices levels resulting from their RFP process (and its negotiated option to purchase LNG based on a hybrid formula that combines Brent and Henry Hub components) that guarantees delivered LNG will always be priced below crude—and therefore, below Hawai'i's oil-based fuel alternatives (pp 6–7).
   - A table recasting Hawai'i Gas's LNG pricing in real and nominal dollars that correlates with the EIA AEO (and updated STEO) price forecasts used in the PSIP

Update, with a request for the Companies to use these "alternative" prices in future models (pp 7–8).

- An explanation of how Hawai'i Gas's LNG supply contract was structured to stabilize and lock in prices over the longer term (p 9).
- Two graphs depicting the enormous dollar amount that LNG use could have saved over the last ten years and is projected to save over the next twenty years (pp 9–10).
- A discussion demonstrating the assumed decline of LNG use over the contract's 15-year lifecycle (compared to the constant LNG use over the 20-year lifecycle in the Companies' plan) and its flexible scaling allowing for the increased penetration of renewable generation alternatives and decreased cost per kilowatt hour (pp 11–14).
- An analysis of the savings that can be realized by the Companies implementing the Hawai'i Gas plan—$3.5 billion over 20 years at constant 800,000 metric tons per annum (mtpa), a bulleted list assessment of the benefits for using the Hawai'i Gas model in the PSIP analysis, and its advantages in supporting State energy objectives (pp 14–18).

County of Maui Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), the County of Maui filed comments in response to Order No. 33740. On July 8, 2016, the County of Maui sent an email to the Companies to clarify and expand on their field comments. Both sets of comments are summarized here.

1. While supporting the complete set of Joint Recommendations, the County of Maui particularly supports recommendations #3, which called for one or more technical conferences to review modeling and assumptions, and #4 (both on page B-69), which calls for the appointment of an Independent Entity (p 2).
2. The Companies cannot be realistically expected to restructure and adopt a new sustainable business model—especially in the face of the disruptive nature of DER services and technologies—and create unbiased resource plans that reflect the best interests of the customers (pp 2–3). Instead, an Independent Entity should direct the preparation of a customer-funded, public interest, resource plan in addition to a PSIP created by the Companies to provide the Commission with a more complete assessment of resource alternatives and proposed capital improvements (p 4).
3. Maui's preferred plan based on Theme 2 triples the island's wind capacity without identifying their general locations and assessing their attendant cultural, environmental, and social impacts (p 5).

4. The flat growth projection through 2045 of DG-PV (in Maui's Theme 2) is not credible, and instead should be replaced with the assumption of a high DG-PV and DER forecast (developed through a collaborative process with the stakeholders), hardwired for 2045, as a starting point, then reverse engineered to the present to better uncover issues that would not have otherwise been raised (p 6).

5. Hardwire a near-term market disruption from distributed energy storage systems (similar to the Morgan Stanley report for Australia's solar plus storage market referenced by TASC's presentation at the Third Stakeholder Conference), then perform an iteration by modeling TASC's dynamic resistive frequency control approach (email).

6. A high DER future in 2045 should be modeled as a starting point, and be defined these five factors: 1. Customer costs from a DER microgrid are less than or equal to the cost of grid services; 2. The DER microgrid performance is greater than or equal to that of grid services; 3. New developments generate their own power and reduce grid growth; 4. Most homes and businesses use onsite energy storage for reliability and security; and 5. All new vehicles are EVs (pp 6–7).

7. The silo approach used to create the PSIP Update resulted in a rigid plan of inflexibility with its inclusion of LNG and a combined cycle plant, relying on a low, limited DG-PV adoption, which only portends to burden ratepayers now and again in the future when investments are made to handle greater distribution-level impacts (pp 8–9).

8. An adjusted value approach should be considered to capture the true value (on a MW basis) and flexibility of energy storage when compared to current fossil-fueled assets (coupled with their laggard deactivation schedule) and when compared to an interisland cable connection (pp 9–10).

9. The inclusion of merged scenarios conditioned upon the approval of the NextEra acquisition reflects bias and intrudes upon the associated deliberations, demonstrating further the need for an Independent Entity who can oversee objectively developed plans (p 10).

Sierra Club Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" page B-70), Sierra Club filed comments in response to Order No. 33740. Those comments are summarized here.

1. The PSIP Update fails to satisfy any of the Commission's Initial Statement of Issues (pp 1–2).

2. The PSIP Update is tainted by its linkage to the proposed NextEra acquisition being approved, and as such is not ownership agnostic nor resource agnostic (pp 4–6).

3. The PSIP Update fails to address the Commission's direction to pursue a new utility and market structure that better serve the interests of its customers and the public, and instead focuses on promoting their traditional business model based on utility capital spending (pp 6–10).

4. The PSIP Update does not include any nearer-term actions aimed at obtaining specific efficiencies and improvements in current generation operations (pp 10–11).

5. The Commission must clarify whether or not the PSIP proceeding has replaced the IRP Framework with its various attendant processes and safeguards (such as an Advisory Group and Independent Entity); and revisit, renew, and reconcile any and all differences (p 12).

6. The PSIP Update continues a bias for switching to LNG with no clear exit plan, prolonging its fossil fuel generation at the expense of pursuing a clean energy portfolio (pp 13–17).

7. The PSIP Update continues a persistent failure to recognize the benefits of DER to the grid and the general public, and to fully integrate and utilize customer DER (pp 18–20).

8. The Commission, at a bare minimum, should ensure an objective and productive planning process by delegating the energy system planning function entirely to an Independent Entity who has the authority to require the Companies to conduct necessary additional planning modeling and analysis (pp 20–22).

SunPower Comments

In addition to signing and supporting the "Ulupono et al Joint Recommendations" (page B-69), SunPower Corporation filed comments in response to Order No. 33740. Those comments, summarized here, include the input SunPower supplied in response to the Companies' solicitation following the Second Stakeholder Conference.

1. SunPower commends the Companies for clearly stating the mix of renewable resources anticipated to meet the 100% renewable energy goal, and for creating a workable plan for attaining that goal (p 2).

2. The expectation of significant savings from the use of LNG as a transition fuel is far from clear, and the transition's substantial capital costs would preclude investments in other more economical technologies (pp 2–3).

3. The use of biomass, its source and infrastructure costs for Maui Electric and Hawai'i Electric require further analysis (p 3).

4. The Companies' and E3's analysis of the costs and amounts of energy storage (Figure B-3.) and PV (Figure B-4)—and their wide range of possibilities—are outdated, insufficient, and inaccurately high; and should instead use the current market assumptions in the GTM Research *PV Systems and Pricing Forecast* or the U.S. Department of Energy *SunShot Vision Study* (both of which we have provided to the Companies) as baseline in further analysis (pp 4–8).

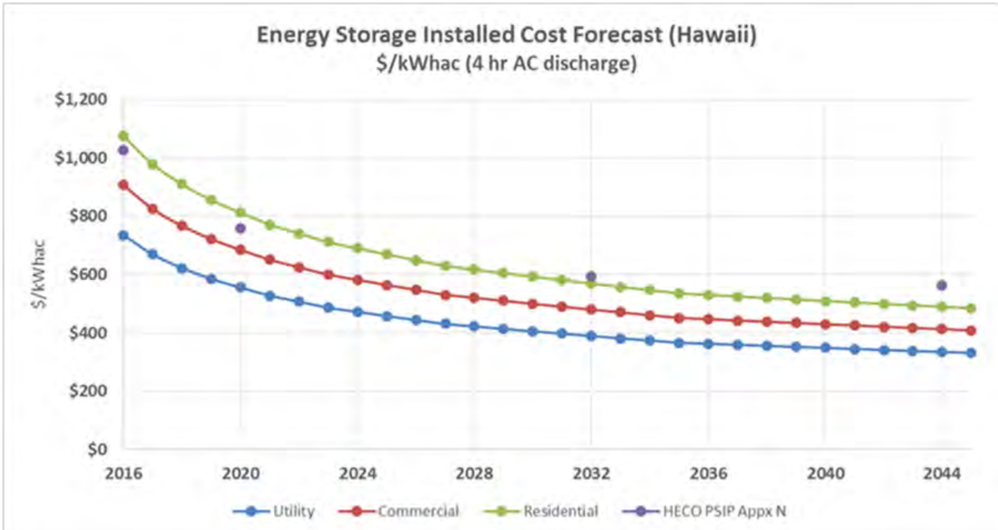

Figure B-3. Comparison of Installed Cost Forecasts for Energy Storage ($/kWh AC)

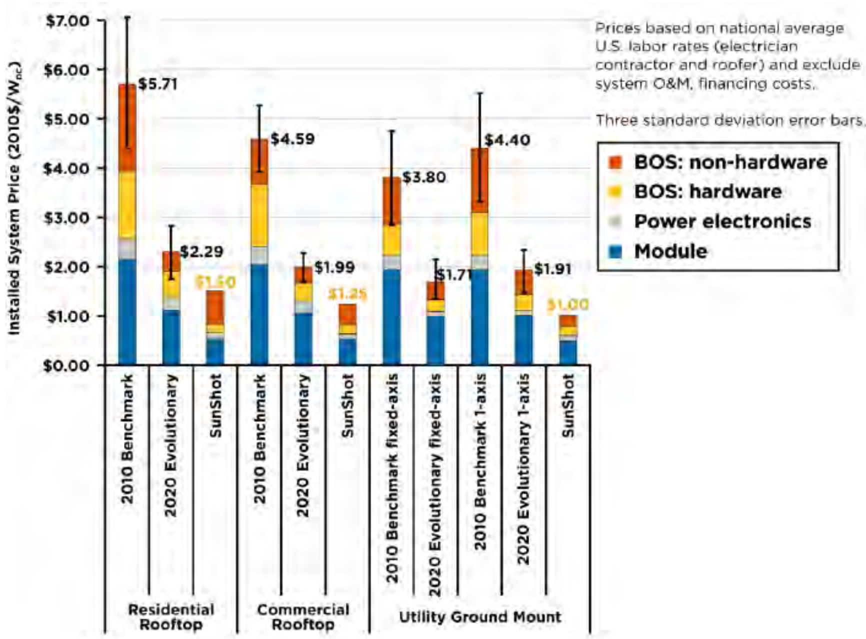

Figure B-4. Installed PV System Price Comparison[48]

[48] U.S. Department of Energy *SunShot Vision Study*, February 2012 (http://energy.gov/sites/prod/files/2014/01/f7/47927.pdf); p. 89.

5. The PSIP Update's assertion of its Theme 2 only being possible in a merged scenario needs closer scrutiny; and its reliance on utility-owned generation and continued operation under a traditional regulatory model are contrary to Commission directives (pp 9–10).

Distributed Energy Resources Council (DERC) of Hawai'i Comments

In addition to signing and supporting both the "Ulupono et al Joint Recommendations" (page B-69) and the "Ulupono et al Annex A Letter" (page B-70), the Distributed Energy Resources Council (DERC) of Hawai'i filed comments in response to Order No. 33740. Those comments are summarized here.

1. The PSIP Update adopts, but fails to integrate distributed energy resources (DER) in its ongoing planning process in a meaningful way, even though DERs can provide a tremendous number of cost competitive benefits to customers, the electrical grid, and all utility customers (pp 5–7).
2. The PSIP Update appear to completely exclude distributed energy storage from its evolving plan, even while acknowledging its value to ancillary services, over-generation, circuit-level issues, and operational flexibility (pp 7–9).
3. The Companies should conduct pilot programs that determine the efficacy of residential distributed energy storage and smart-supply DERs (to function as a hybrid between self-supply and grid-supply systems) to better determine how they can export on the shoulders of the load curve, capture excess energy, and shift peak load (pp 10–12).
4. The PSIP Update fails to consider the positive financial impact of both customer-invested and utility-invested distributed energy storage (pp 12–14).
5. DERC opposes the proposed investment in LNG, preferring to understand what the $1.3 billion investment slated for LNG development could achieve if invested directly into infrastructure that support renewables (p 14).
6. The PSIP Update, while recognizing the value of keeping customers connected to the grid, fails to offer any substantial plan to encourage connected nor analyze the economic potential for customer exit (p 15).
7. DERC recommends (p 16):
   - The appointment of an Independent Entity to monitor future proceedings.
   - An upgraded and revamped analytical strategy to include dynamic and stochastic models that incorporate all potential DER attributes.
   - Parallel investments in rigorous pilot projects to investigate DER impacts and contributions.

Hawai‘i PV Coalition (HPVC) and The Alliance for Solar Choice (TASC) Comments

In addition to signing and supporting the “Ulupono et al Joint Recommendations” (page B-69), the Hawai‘i PV Coalition (HPVC) and The Alliance for Solar Choice (TASC) jointly filed comments in response to Order No. 33740. Those comments, summarized here, also include the input TASC supplied in response to the Companies’ solicitation following the Second Stakeholder Conference and an email TASC sent to the Companies on July 13, 2016.

1. The PSIP Update provides no insight or analysis of alternative DER configurations that could address system constraints and avoid distribution and transmission system upgrades (p 4).
2. The PSIP Update lacks analysis of non-capital alternatives that address DER integrations and interconnections costs (p 5).
3. The PSIP Update does not identify or examine the benefits of DER in providing ancillary services, nor explain its absence from the preferred plans (pp 5–6).
4. The DER forecast of a steep decline for DG-PV and distributed energy storage installations over the next ten years defy common sense and are, on first impression, unreasonable. TASC, using the model input data, intends to conduct its own analysis and devise its own outputs and conclusions (p 6).
5. The PSIP Update reveals a continued dedication to preserving a traditional utility-centric business model rather than embracing a customer-focused one (pp 7–8).
6. The Commission should appoint an Independent Entity to oversee the work of finalizing the PSIP, and be granted authority to (pp 8–11):
   - Access all models and underlying data, inputs, and assumptions.
   - Revise operational parameters within the models.
   - Direct the compilation of three to five alternate scenarios in the public interest.
7. Continued analysis should include a safety valve (load bank) to control excess energy risks, reduce down reserves, and reduce curtailment of renewable resources (email).

Summaries of Remaining Party Responses

Paniolo Power Comments

In addition to signing and supporting the “Ulupono et al Annex A Letter” (page B-70), Paniolo Power filed comments in response to Order No. 33740. Those comments are summarized here.

1. The PSIP Update suffers from many material shortcomings that do not support the Commission's Initial Statement of Issues because of bias toward the Companies' self-interest and a dependency on NextEra's acquisition of the Companies (p 4).

2. The Hawai'i Electric Light preferred plan is unclear why more long-duration storage, wind, and PV resources are not included; geothermal was selected as the next generating unit given its uncertainty; and the resultant financial analysis was optimized (pp 6–8).

3. The basis for unit deactivation, resource addition, must-run generation reduction for Hawai'i Electric Light is unclear (pp 9–11).

4. The selection and addition of renewable resources for Maui Electric is more aggressive than that for Hawai'i Electric Light despite the similarity of our grids (pp 11–14).

5. Hawai'i Island projects should be given higher priority because of it higher rates and lower rate of return when compared to O'ahu and Maui (p 15).

6. The PSIP Update should contain more resource diversification obtained in a competitive bidding process, and not based on using LNG (acquired only after a NextEra acquisition) or using biofuels in existing fossil-fueled generation (pp 15–18).

7. Integrated energy districts—microgrids—should be required for communities with health facilities for life, safety, and security; and not just for military installations (p 18).

8. Paniolo Power suggests the Commission consider these procedural steps (pp 23–24):
   - Schedule another informal PSIP stakeholder meeting.
   - Allow the Parties to submit written questions to the Companies.
   - Direct the Companies to respond to these questions in writing.
   - Hold technical sessions to discuss and elaborate on these and other questions and responses (retaining a court report to document the sessions).
   - Direct the Companies to provide supplemental responses as needed.
   - Allow the Parties make specific recommendations to any part of the PSIP preferred plans, including their own analysis and modeling.
   - Direct the Companies to revise and resubmit the PSIP.
   - Allow the Parties to write final statements of position and recommendations regarding the revised and resubmitted PSIP.
   - Decide whether to accept, reject, or modify the PSIPs, and determine the effect of its decision on future applications and proposals.

Life of the Land and Puna Pono Alliance Comments

Life of the Land and Puno Pono Alliance jointly filed comments in response to Order No. 33740. Those comments, related through metaphor and anecdotes without citation, are summarized here.

The PSIP, as an evolving plan, still needs more work in a number of areas. Many key assumptions—such as load and demand shifting, energy storage, microgrids, geothermal, DER, and identification of sources—and their basis should be transparently detailed.

Renewable Action Coalition of Hawai'i (REACH) Comments

The Renewable Action Coalition of Hawai'i (REACH) filed comments in response to Order No. 33740. That filing included a twenty-three-page publication entitled *Creating the Electric Utility We Want in Hawai'i or Anywhere* (originally submitted in response to the Companies' solicitation following the Second Stakeholder Conference) and comments regarding the *PSIP Update Report: April 2016*.

The REACH publication, informational by its own admission, presents a five-step process for building consensus to successfully achieve 100% renewable energy. REACH's additional comments specifically filed in response to Order No. 33740 are summarized here.

1. The PSIP Update (although with some amount of ambivalence) fails to elucidate plans that can inform Commission decisions, in general, because the Companies have not reached consensus of a clear renewable planning process, and its attendant generation resources (most notably LNG), associated risks, and benefits (pp 33–47).
2. The PSIP Update does not comply with the Commission's stated component plans mainly because the Companies have not arrived at consensus as to the fundamental components of each plan (pp 47–51).
3. The PSIP Update has not either arrived at consensus, adequately addressed, or sufficiently justified the Commission's Observations and Concerns (pp 52–57).
4. The Commission might consider suspending the docket until the Companies reach consensus on a renewable planning process to systematically evaluate renewable energy options (pp 57–58).

County of Hawaiʻi Comments

The County of Hawaiʻi filed comments in response to Order No. 33740. Those comments, summarized here, include the input the County of Hawaiʻi supplied in response to the Companies' solicitation following the Second Stakeholder Conference. The County of Hawaiʻi:

1. Supports the joint recommendations of the Ulupono Initiative et al filing, certain comments by Paniolo Power, and the County of Maui's call for an Independent Entity to direct the preparation of a ratepayer-funded public interest resource plan to counter the Companies' shareholder-funded resource plan (pp 1–2).
2. Increase the overall transparency and provide access to data necessary to collaboratively conduct independent analyses and modeling for developing alternative strategies (p 3).
3. Submits that the Hawaiʻi Electric Light Preferred Plan does not provide useful analyses to inform major resource acquisitions, nor does it appear to be well-reasoned from a ratepayer's standpoint (p 3).
4. Considers the Component Plans to be inadequate, not sufficiently analyzed, not good enough, questionable, non-existent content, and botched (p 4).
5. States that the *PSIP Update Report: April 2016* does not, insufficiently, or inadequately address all eight Observations and Concerns (p 5).
6. For Hawaiʻi Electric Light, asserts that Hawaiʻi Island projects be prioritized, that a diversified portfolio of renewable generation displace oil-fired plants (not converted to LNG), that Hawaiʻi Gas supplied LNG should be analyzed, and all new generation be competitively bid, a process that the Commission should revisit (p 6).
7. Further asserts that the Hawaiʻi Electric Light preferred plan (pp 7–8):
   - Is uncertain and risky (p 7).
   - Is not a diversified renewable energy portfolio (even though Hawaiʻi Island has more Class 7 (on public display) onshore wind resources, Maui installs four to five times more new wind resources) (p 7).
   - Doesn't include long-duration storage (p 7).
   - Doesn't fully address ancillary services (p 7).
   - Doesn't sufficiently include integrated energy districts or microgrids which should be considered for communities with health facilities for life safety (p 8).
   - Fails to deactivate fossil generation at the expense of burning biofuels which impedes transformation planning (p 8).

8. Considers the Maui Electric preferred plan more diversified; and finds the lack of pumped storage hydro coupled with cost-effective wind resources developed at North Point, South Point, Lalamilo, and Parker Ranch concerning (p 9).

9. Has retained the services of some of the nation's leading power systems engineers and energy economists—their modeling team based at Arizona State university—to develop an independent, objective, third-party integrated resource plan for Hawai'i Island, consistent with the 100% renewable energy target, that could potentially be extrapolated to other Hawaiian Islands, and further petitions the Commission to require the Companies to provide (through protective agreements or non-disclosure agreements) the information necessary for their modeling team to perform their work (pp 9–12).

Tawhiri Power Comments

Tawhiri Power filed comments in response to Order No. 33740. Those comments are summarized here.

1. Discussion on the PSIP Update should be delayed until future technical conferences can establish "best practices" to pave a concerted path for all involved (p 3).

2. A vertically-integrated utility model should not be relied upon for planning a transition from fossil-fueled generation to 100% renewable generation, as this is, at best, a first step. The process for creating the PSIP Update is largely a utility-based approach borrowed largely from mainland experiences that do not reflect the dynamics of Hawai'i's IPP and DER markets nor local county economics (p 3).

3. The next steps must assure the integration of non-utility generation alternatives that provide the least cost and most benefit for local economies (p 3).

Department of Business, Economic Development, and Tourism (DBEDT) Comments

The Department of Business, Economic Development, and Tourism (DBEDT) filed comments in response to Order No. 33740. DBEDT's comments are summarized here.

1. The PSIP should be a clear plan for delivering electricity and energy services, be approved by the Commission, and focus on a five-year action plan that also forms the basis for a long-term plan (p 5).

2. The Companies should continue to engage stakeholders and incorporate their input (forecasts, resource options, constraints, and framework) into your analyses (p 7).

3. The five-year plan must include an implementation timeline overlaid with other dependent dockets; clearly present all alternatives; await direction on interisland

transmission and LNG; base resources costs on agnostic ownership; include replacement renewable energy generation that is technology agnostic and ranked on such factors as dispatch time, delivery time, and energy cost; and be fulfilled through expeditiously issued RFPs. Their view of the five-year plan appears in a five-tiered table outlining RFPs for procuring renewables, grid-scale storage, general, and LNG overlaid with concurrent efforts (pp 7–12).

4. Individual case runs should not substitute for capacity expansion modeling by E3, which can be used to validate case run conclusions (p 12).

5. The PSIPs can be tested using the capacity expansion models to determine if there is a benefit to increased renewable adoption (p 15).

6. The Companies' approach to iteratively look at DER and DR based on costs resulting from proposed resources is positive (p 15).

7. The PSIP should include a comprehensive analytical framework of detailed and independent unbiased scenario analysis, as well as include a broad range of resource options, their costs, and their benefits (pp 12–13).

8. DBEDT cannot comment on the Component Plans (Appendix M: Consultant Reports of the *PSIP Update Report: April 2016*) nor on six of the eight Observations and Concerns (#1 and #4–#8) because they are contingent upon interisland transmission and LNG, two issues that remain unresolved (pp 14–15).

9. Observations and Concerns #2 and #3 can both be tested using capacity expansion models for increasing the pace of adopting renewables (pp 15–16).

10. While concurring with the need to modernize O'ahu's generation fleet, DBEDT questions whether the proposed Kahe 3x1 CC power plant represents the best benefit to cost ratio, and recommends further analysis employing capacity expansion models be completed within 21 days—in other words, by July 8, 2016 (pp 16–17).

11. DBEDT questions the validity of several purported benefits of the Kahe 3x1 CC plant—reduced customer costs; avoided environmental compliance costs; improved fuel savings and efficiencies; avoided O&M costs; and lowered results from the calculations that determined fuels and heat rate savings, and capital recovery costs—and recommends more detailed analysis using more relevant cases that enable better comparison among options be completed within 21 days—in other words, by July 8, 2016 (pp 16–27).

12. How all available portfolio options were compared is unclear despite the analysis of over a hundred cases. For example, is the Kahe 3x1 CC a better option to a smaller build-out with fewer deactivations; or to using biofuels versus becoming a stranded asset in the face of alternative renewable options (p 18)?

13. DBEDT identified five procedural "next steps" that the Commission should consider:
    - Continuing collaborate planning (p 27).
    - Updating and improving "scenario analyses", including new resources, constraints, forecasts, and list of resources, when modeling especially with the RESOLVE O'ahu case runs (p 28).
    - Developing an analytical framework within which all future analysis is performed, especially for capacity expansion modeling conducted by E3 with RESOLVE (pp 28–29).
    - Conducting specific analyses for multiple interisland transmission options, including procurement, installation, interconnection, and grid update costs (pp 29–30).
    - Developing specific work products and activities (such as a list of resources and a resource description template), and holding another conference to solicit stakeholders feedback on this process (pp 30–31).
14. DBEDT believes that the Companies should be required to (pp 31–32):
    - File a comprehensive, complete, and final PSIP within 120 days—by October 15, 2016.
    - Complete the interisland transmission analysis, and present its findings and recommendations within 120 day—by October 15, 2016.
    - Provide further detail and analysis of a more granular Theme 3 (renewables without LNG) within 75 days—by August 31, 2016.
    - Provide further detail and analysis about the Kahe 3x1 CC plant incorporating DBEDT's comments within 21 days—by July 8, 2016.
15. DBEDT recommends the Commission appoint an independent facilitator to monitor and provide specific guidance to the Companies in the completion of its PSIP (p 32).

AES Hawai'i Comments

AES Hawai'i filed comments in response to Order No. 33740, which also contain the substance of their letter to the Companies on May 31, 2016 following the Second Stakeholder Conference. AES's comments are summarized here.

1. The 2014 PSIP Preferred Plan sought to renegotiate the AES PPA and convert the plant to a 50/50 biomass and coal fuel mix, while the *PSIP Update Report: April 2016* cancels the PPA when it expires on September 1, 2022 (p 2).
2. Any phase out of the AES plant or premature PPA cancellation should not jeopardize electricity reliability (pp 4–5).

3. The methodology for retiring units and adding replacement generation is not transparent; the plans for LNG retrofits is not sufficiently justified and is at the expense of not seeking lower-cost grid-scale renewable resources (p 5).

4. The plan continues to grow Company-owned generation assets (Kahe 3x1 CC plant, Maui generation, and the HEP purchase). The Companies should not be allowed to avoid the competitive bidding framework without seeking lower-cost options (p 6).

5. Cancelling the AES PPA while proposing a transition to LNG should the Companies merge with NextEra shows plan bias (p 6).

6. Deactivating units, rather than retiring them, keeps them in the rate base, unnecessarily raising customer rates; because it is unclear that these units will be used for capacity planning (pp 7–8).

7. The filing of three applications on May 18, 2016 portend the Companies' implementation of the unapproved PSIP (p 8).

Division of Consumer Advocacy Comments

The Division of Consumer Advocacy (DCA) filed comments in response to Order No. 33740. Those comments are summarized here. The Consumer Advocate:

1. Strongly urges the Commission to consider an integrated, consolidated review of various resources (generation, DR, storage, and others) in lieu of the current fragmented approach (p 6).

2. Urges the Commission to focus on the five-year horizon that comprises the action plan and de-emphasize the need for a long-term plan (that is, years 6 through 30) because no one is capable of providing accurate and reliable forecasts for the next 30 years. The rationale: short-term actions are more salient and are more readily implemented, while long-term actions can and will be reviewed—and likely changed—in future iterations of the resource plans. The Commission should require all Parties to apply the same focus to develop an orderly and timely resource plan (pp 7–10).

3. Illustrates in Attachment A (pp 29–30) how the action plan can identify key decision points to determine how to proceed (p 11).

4. Recommends that the PSIP be viewed as the development of a decision tree that can be used as a tool within which to evaluate the reasonableness of any particular course of action (p 12).

5. Suggests procedural steps for the remainder of this proceeding as follows (p 13):

Procedural Step:	Date:
Stakeholder Conference	June 29, 2016
Technical Meeting 1	July 2016: second week
Technical Meeting 2	July 2016: fourth week
Simultaneous IRs	August 2016: first week
IR responses	August 2016: third week
Hawaiian Electric's Addendum Filing	August 1, 2016
Simultaneous IRs	September 2016: first week
IR responses	October 2016: third week
Final Statements of Position	November 2016: second week
Proposed Decision and Order	December 2016: second week
Hawaiian Electric response, if necessary	January 2017: second week
Final Decision and Order	January 2017: fourth week

6. Recommends comparing the results from different models (RESOLVE, SWITCH, and P-Month) using *the same set of inputs* (emphasis theirs) to establish consistency and optimized planning (p 17).

7. Recommends that stakeholders be given another opportunity (a two-week window) to review the modeling assumptions and provide proposed assumptions with supporting documentation (pp 18–19).

8. Contends that a "least cost" reference case where system costs are minimized irrespective of RPS and EEPS targets would provide a useful benchmark to compare against other plans (p. 19).

9. Recommends additional steps focusing on quantitative (and not qualitative) metrics should be taken to verify that the PSIP results are consistent with an optimized resource plan (p 21):
   - Analyze the optimal mix versus renewable penetration levels to minimize costs.
   - Analyze sensitivities on varying levels of resources (such as DR and energy storage).
   - Explain in detail the rationale for determining the optimum mix of generation build-out and deactivation.
   - Document how resource availability was determined.
   - Compare the Companies' results to those of its consultants.

10. Recommends the following actions be taken to minimize the cost of a generation build-out and deactivation (pp 23–24):

- Evaluate how system security and reliability criteria affect costs.
- Describe the methods used to minimize the cost of a build-out.
- Review the sub-hourly and system hosting capacity analyses.

11. Recommends that plans including LNG must include a thorough assessment of the risks and costs of converting the Companies' current generators to burn natural gas (pp 24–25):

- Describe how existing units will be converted, and what physical upgrades and changes are required.
- Describe what equipment will be required to process LNG.
- Identify conversion costs for each unit and costs associated with purchasing and building costs associated with the LNG facilities.

12. Contends that the role of resource ownership in the planning process must be revisited (pp 25–26).

13. Suggests that more work is necessary to identify grid monitoring and control challenges (pp 27–28); and recommends the following actions:

- Clearly identify what problems are anticipated for an electrical grid with a large amount of renewable energy from a system security standpoint.
- Identify what solutions are proposed to address these problems.
- Provide a detailed description of the methods used to address the costs of solutions.

Hawaiian Electric Companies Comments

The Companies filed comments in response to Order No. 33740. Those comments are summarized here.

1. The *PSIP Update Report: April 2016* represents the Companies' best efforts to develop a plan to achieve 100% renewable energy by 2045 (pp 1–2).

2. The *PSIP Update Report: April 2016* outlines a five-year action plan that incorporated a complete grid transformation, considered numerous planning consideration (chief among them, changing our planning horizon from 15 years to 30 years), and that should be implemented in the short term to start on the road toward achieving 100% renewable generation (pp 2–5).

3. The Companies are working on a supplement to the *PSIP Update Report: April 2016* (as outlined in Chapter 9: Next Steps of that report) and moving to implement the five-year action plan (p 5).

4. The Companies plan to regularly update our resource plan to provide optimal pathways toward achieving the 100% renewable energy goal (p 6).

General Public Comments

There were 174 total responses from the general public to Order No. 33740 (two of which were submitted after the deadline). All but three of these 174 responses from the general public commented mostly on hierarchical issues surrounding the *PSIP Update Report: April 2016*. Table B-12 summarizes these comments.

Comment	Number
Against LNG transition	135
Greater environmental consideration (also against LNG for the same reason)	1
Supports LNG transition	3
Against smart meters (one is also against 100% renewables)	32
Supports pumped storage hydro (PSH) projects on O'ahu and Maui	2
Commented on the initial statement of issues and the Observations and Concerns as they relate to Lana'i (detailed in the narrative)	1
Total	*174*

Table B-12. Summary of General Public Responses to Order No. 33740

Two general public comments support pumped storage hydro (PSH) projects. One (by the Vice President of a company that develops "sustainable energy projects for Hawai'i") supports PSH on Maui and O'ahu; and one supports a complete transition of the Maui grid to two PSH systems (proposed by a company who also proposes to develop and build these systems).

One filing was submitted by Sally Kaye (as a personal statement), selectively commenting on the Commission's initial statement of issues and Observations and Concerns, on the Lana'i preferred resource plan, and some general observations.

1. The Companies continue to signal their intent on ownership of power supply and generation instead of exploring alternative business models.

2. The Update does not adequately address the speculative nature of geothermal on Maui island.

3. The Update does not adequately explain the termination of the AES PPA, nor compare that decision with the cost of converting the plant to biomass, nor identify the renewable energy sources to replace the AES load.

4. The deactivation plan appears to unreasonably shift all risk to customers, and does not identify any customer benefit for the proposed nonbypassable recovery fee. In addition, it's unclear if the proposed consolidated rates would fairly assign deactivation costs to only those customers affected or borne by all customers.

5. The proposed Construction Work in Progress (CWIP) recovery mechanism (which is contrary to traditional regulatory "used and useful" and "placed-in-service" policies) is not subject to prudency reviews, time-limited collections, return of funds collected if construction is not completed, nor true-up measures.

6. At least for Maui island, the Update has not fully analyzed the most economical means for providing ancillary services as required by Observation and Concern #6.

7. The contention that O'ahu cannot provide for its own [renewable] energy needs is based on pure speculation and is not factually supported, and thus does not substantiate the need for analyzing interisland transmission.

8. The Lana'i preferred resource plan fails to adequately analyze or substantiate the details around installed wind energy in 2020, 2030, and 2045; acknowledges that the plan is not based on a complete financial model; fails to deactivate any generation assets; acknowledges uncertainty with the majority landowner plans; fails to fully analyze the DG-PV potential.

9. The PSIP Update contains a number of questionable actions: the implementation of more renewables at the expense of a long-term LNG commitment, a questionable financial position that has unadvisedly deferred capital expenditures, undervaluing energy efficiency, and incomplete consideration of customer preferences especially around siting replacement generation.

ORDER NO. 33740: PARTY INPUT AND OUR RESPONSE

The Commission issued Order No. 33740 inviting the Parties and "interested persons who are not Parties to this docket" to submit comments on our *PSIP Update Report: April 2016*, asking responders to focus mainly on the Initial Statement of Issues outlined in Order No. 33320.

As with Party responses to Order No. 33320, we organized their comments into 15 topics and responded to these topics in essentially the same way (as outlined in "How We Considered and Incorporated Input from the Parties" on page B-51).

Responding to Order No. 33740 Party Input

Table B-13 contains a cross reference between a Party filing and the 15 topics. A checkmark indicates that a Party commented on that topic; a dash means that they did not comment on the topic. The remainder of this section explains each topic and our response.

Party	1. PSIP Process	2. Independent Entity	3. Conferences	4. PSIP Input & Analysis	5. PSIP Generation	6. Capacity Expansion Models	7. Interisland Transmission	8. Fuels & Forecasts	9. DER & DG-PV	10. LNG	11. Renewable Energy on O'ahu	12. Microgrids	13. Energy Storage	14. Utility Ownership	15. Customer Retention Economics
CoH	√	√	√	√	√	–	–	–	–	–	–	√	–	–	–
CoM	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
DBEDT	√	√	–	√	√	√	–	–	√	–	–	–	–	–	–
DCA	√	–	–	√	–	√	–	–	–	√	–	–	–	√	–
AES	–	–	–	√	√	√	–	–	–	√	–	–	–	√	–
Blue Planet	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
DERC	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
Eurus	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hawai'i Gas	√	√	√	–	√	√	√	√	√	√	√	√	√	–	√
HPVC*	√	√	√	–	√	√	–	–	√	–	–	–	–	√	–
HREA†	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
HSEA†	√	√	√	–	√	√	–	–	–	√	–	–	–	√	–
LOL‡	–	–	–	√	–	–	–	–	–	–	√	–	–	–	–
NextEra	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Paniolo Power	√	–	√	√	√	√	√	–	√	√	√	√	√	√	√
Puna Pono‡	–	–	–	√	–	–	–	–	–	–	√	–	–	–	–
REACH	√	–	–	√	–	–	–	–	–	–	–	–	–	–	–
Sierra Club	√	√	√	–	√	√	√	–	√	√	√	√	√	√	√
SunEdison	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SunPower	√	√	√	–	√	√	–	–	–	–	–	–	–	√	–
TASC*	√	√	√	–	√	√	–	–	√	–	–	–	–	√	–
Tawhiri	–	–	√	√	√	–	–	–	–	–	–	–	–	√	–
Ulupono	√	√	√	√	√	√	√	√	√	√	√	√	√	√	√

* = HPVC and TASC jointly filed a response.
† = HREA and HSEA did not file individual responses, only signing onto the 'Ulupono et al' response.
‡ = Life of the Land and Puna Pono jointly filed a response.

Table B-13. Party to Order No. 33740 Input Topic Cross Reference

1. PSIP Process

Party Comments

All responding Parties but one request that the process for creating the PSIP be expanded and formalized to include their direct involvement to better enable a collaborative approach for creating the PSIP. This approach includes the Commission, the Parties, and the Companies working together to develop the PSIP. Toward that end, these Parties request that the Companies:

- Provide information to the Parties necessary for them to conduct their own independent modeling and analysis for developing independent resource plans, and to review, comment, and present specific alternatives to all input and modeling assumptions.
- Allow the Parties to submit questions that the Companies respond to in writing. If necessary, hold technical conferences to discuss and elaborate on these and other questions and responses.
- Incorporate the Parties' independent studies and analyses, as well as their alternative input and modeling assumptions, into the PSIP process.
- Incorporate impartial generation resource technologies and ownership.
- Present a draft PSIP to all Parties for review and comments, and transparently finalize the PSIP based on Party comments.
- File a PSIP focused on preferred resource plans and concomitant five-year action plans for each island served (identifying key decision points) whose steps are concurrent with all other relevant dockets. These action plans must form the basis for long-term (thirty-year) decisions.

Using this filed PSIP, the Parties recommend preferred resource plans and its five-year action plans. The Commission rules on all submissions, modifies them as they see necessary, and chooses preferred resource plans for the operating utilities. The Commission establishes dates to formally review the status and progress that each operating utility is making on its preferred resource plan.

Parties Issuing These Comments

County of Hawai‘i, County of Maui, DBEDT, Consumer Advocate, Blue Planet, DERC, Hawai‘i Gas, HPVC, HREA, HSEA, Paniolo Power, REACH, Sierra Club, SunPower, TASC, and Ulupono.

Our Action Regarding this Topic

Input assumptions are critical to sound modeling and analysis. Toward that end, we invested significant time, energy, and expertise to develop our resource cost assumptions and all other input assumptions. To ensure the reasonableness of these estimates, we engaged NREL to conduct a third-party review.

Throughout, we have shared these modeling assumptions (including resource cost and fuel price forecast information) and posted it on our FTP (WebDAV) site so that all the Parties could access it. The Parties were free to use this information to conduct their own independent modeling and analysis (for instance, by running the SWITCH modeling tool) to develop independent resource plans.

Since the outset of this proceeding, we actively sought, on numerous occasions, the assistance of the Parties to provide input about resource cost assumptions and resource potentials that could be properly vetted and incorporated into the PSIP analyses. During that time, we have considered and incorporated input from several Parties: renewable energy cost assumptions from SunPower, LNG fuel price forecasts from Hawaiʻi Gas, PV and wind resource potentials for Oʻahu from Ulupono (Dr. Fripp), and wind and pumped storage hydro information from Paniolo Power. Other Parties have submitted input to us, which we have incorporated into our sensitivity analyses. (We thoroughly examine this information in "Input Incorporated into Our PSIP Update Report" starting on page B-13.)

The Parties have had numerous opportunities to submit comments and input to us for use in creating the PSIP. Since December 2015 and continuing through the end of October 2016, the Parties benefitted from the many opportunities to engage with us about all aspects of modeling, analyzing, and developing our PSIP. We have hosted three stakeholder conferences, four organized stakeholder meetings, a handful of scheduled conference calls, and dozens of extemporaneous and planned meetings with the Parties; and participated in four Commission-sponsored technical conferences. We invited the Parties to present at two of our stakeholder conferences: eight Parties did. We distributed the contact information of our PSIP Project Lead, inviting the Parties to email and call him. After filing our *PSIP Update Report: April 2016*, we also invited the Parties to submit comments and input about that PSIP after we discussed that report during our Second Stakeholder Conference.

Ulupono Initiative, through its work with Dr. Fripp, has presented findings from analyses produced using the SWITCH modeling tool. In discussions with Dr. Fripp, we learned this modeling developed a lowest cost, technically feasible result, however, the model didn't consider land-use, community, social, environmental, nor commercial issues. As a result, we re-evaluated the screening criteria for grid-scale PV, requested NREL to update and expand the inputs to its resource potential studies.

NREL subsequently revised their report (included in Appendix F: NREL Reports), adding a brief appendix, that explains the differences in results related to land-use assumptions.

In our modeling, we have worked to optimize DR, DER, and grid-scale resources while meeting the RPS requirements necessary to achieve 100% renewable generation by 2045. Cost and reliability are significant drivers in this optimization. For the April PSIP, we applied the Decision Matrix (outlined in Appendix C: Analysis Methods and Models) in meetings attended by three intervenors: Consumer Advocate, DBEDT, and County of Hawaiʻi to identify the Preferred Plans. (We posted all analyses output files on the FTP (WebDAV) site for Party access.) For the December 2016 PSIP, we are employing a process involving the RESOLVE and PowerSimm modeling tools, with interactions with the PLEXOS modeling tool, to evaluate and select final action plans.

Both the *PSIP Update Report: April 2016* and the subsequent *PSIP Update Report: December 2016* represents our concerted efforts to develop five action plans. These action plans consider and incorporate numerous planning options, including a complete grid transformation, to draw a roadmap for achieving 100% renewable generation by 2045 while stabilizing rates, and maintaining a secure and reliable grid. These action plans can be implemented in the near-term, and form the foundation for long-term planning.

Today's electric industry has become increasing dynamic; change, sometimes seemingly overnight, has become the norm. As such, we plan to regularly update the resource cost and other input assumptions necessary to adjust our PSIP to keep pace with these volatile circumstances.

2. Independent Entity

Party Comments

The responding Parties recommend the Commission appoint an Independent Entity to perform two fundamental functions:

- To direct the preparation of a customer-funded, public interest, resource plan.
- To monitor the PSIP proceeding, include the Parties as necessary, assess all inputs and models, revise operational parameters, and guide the completion of the PSIP.

The purpose of this dual path is to ensure an objective and productive planning process and to provide the Commission with a more complete assessment of resource alternatives and proposed capital improvements.

The Commission must also clarify the current process of creating the PSIP, and whether that process should be replaced with the IRP Framework, an Independent Entity, and an Advisory Group with its attendant safeguards.

Parties Issuing These Comments

County of Hawaiʻi, County of Maui, DBEDT, Blue Planet, DERC, Hawaiʻi Gas, HPVC, HREA, HSEA, Sierra Club, SunPower, TASC, and Ulupono.

Our Action Regarding this Topic

To develop the *PSIP Update Report: April 2016*, we created a Decision Matrix (see Appendix C: Analysis Methodologies of that PSIP report) that enabled us to define objectives, set requirements, and consider the various inputs and assumptions that feed into the PSIP planning and modeling, and best determine the quantity and timing of DER, DR, and grid-scale resources.

Using this Decision Matrix, we defined a number of hierarchical themes; defined an array of resource costs, input variables, and assumptions; and developed hundreds of candidate resources plans incorporating these input assumptions and numerous sensitivities. We performed this analysis using various models and cross-checked results to compare and contrast output, to better ensure the accuracy of our analysis and process. We then conducted a rigorous down-selection process (in the presence of the Intervenors) to methodically hone in on our preferred resource plans—all of which maintain system security with reasonable rates, and attain the renewable generation levels mandated by statute.

This decision-making process prioritized regulations and requirements, cost, reliability, renewable generation levels, and other decision priorities as directed.

We followed a different process for our *PSIP Update Report: December 2016*. Based on developments since April 1, 2016, many of the resource costs, inputs, and assumptions changed, as has our foundational themes (especially since NextEra's proposal to acquire the Companies was not approved by the Commission).

Throughout this entire process of over a year, we continually solicited input from the Parties, yet received little actionable input in return. We did receive input from a few Parties—Hawai'i Gas, SunPower, Ulupono, and Paniolo Power of particular note—that, after some modification, was usable in our modeling analysis. The remaining bulk of Party input consisted of suggestions, comments, and concerns.

We are employing multiple industry-leading modeling tools—RESOLVE, PowerSimm Planner, and PLEXOS—to conduct the analyses necessary to develop our December 2016 PSIP. Two of our consultants, E3 and Ascend Analytics together with our resource planning team, are running these models. Our foundational set of input and resource cost assumptions, combined with the Party input (mentioned above), was then fed into these models to be analyzed. The models then chose the elements that comprise our five near-term action plans. (See Chapter 3: Analysis Approach for a detailed discussion of the process.)

Given this, unless relying on substantially different input assumptions, modeling tools, and decision priorities, it is unclear how a planning process directed and overseen by an Independent Entity would arrive at substantially different results and resource plans.

3. Stakeholder and Technical Conferences

Party Comments

Most of the responding Parties requested that the Companies hold another stakeholder conference. The purpose of the conference is to enable greater collaboration and increase dialog.

The Parties also requested one or more technical conferences to discuss the RESOLVE and SWITCH capacity expansion modeling tools, their inputs and assumptions, and how they can identify alternative generation resource mixes for attaining a 100% clean energy future; to review modeling input and assumptions; and to establish "best practices" to pave a concerted path for all involved

Parties Issuing These Comments

County of Hawai'i, County of Maui, Blue Planet, DERC, Hawai'i Gas, HPVC, HREA, HSEA, Paniolo Power, Sierra Club, SunPower, TASC, Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

In response to requests from the Parties, we held a Third Stakeholder Conference on June 29, 2016. (We previously held stakeholder conferences on December 17, 2015 and on May 17, 2016.) At this third conference, four Parties gave presentations: Blue Planet, TASC, DBEDT, and Ulupono. Our consultant, E3, presented their RESOLVE modeling tool and the Companies mapped out next steps. The conference also enabled the Parties to engage in a discussion with us about topics of their choosing. (See "Third Stakeholder Conference: June 29, 2016" on page B-110 for details.)

We also held a series of stakeholder meetings from August through October 2016 to discuss Party input. (See "Stakeholder Meetings" on page B-123 for details.)

4. PSIP Input, Assumptions, and Analysis

Party Comments

About half the responding Parties submit that the *PSIP Update Report: April 2016*:

- Does not fully address the Initial Statement of Issues: 1.) Is not well-reasoned nor diversified enough, is predicted on attaining a predefined "end state", and does not provide useful nor complete analyses to inform major resource acquisitions; 2.) Insufficiently and inadequately addresses the seven Component Plans; and 3.) Does not adequately or sufficiently address all eight Observations and Concerns.
- Does not fully explain the means for financing capital expenditures nor the total financial implications for customers.
- Is largely utility-based and not in the interest of customers.

- Lacks a thorough analysis of Theme 3 (renewable generation without LNG).
- Does not adequately explain the AES PPA termination.
- In its deactivation plans, appears to unreasonably shift all risk to customers, does not identify any customer benefit for the proposed nonbypassable recovery fee, and appears to unfairly assign deactivation costs to all customers

These Parties submit that the PSIP should:

- Be a comprehensive analytical framework of detailed and independent unbiased scenario analysis, as well as include a broad range of resource options, their costs, and their benefits.
- Explain clear plan for delivering electricity and energy services.
- Include a benchmark "least cost" reference case (regardless of generation type) to be used for comparing other potential plans.
- Update the costs, quantities, and timing of LNG to those provided by Hawai'i Gas; as well as for energy storage and PV values provided by SunPower.
- Adjust many input assumptions—build-out and deactivation costs; system security and reliability criteria costs; sub-hourly and system hosting capacity inputs; system impacts of large amounts of renewable energy integration; load and demand shifting, energy storage, microgrids, geothermal, DER, and identification of sources input—and transparently detail their basis.

Parties Issuing These Comments

County of Hawai'i, DBEDT, Consumer Advocate, AES Hawai'i, Life of the Land, Paniolo Power, Puna Pono, REACH, Sally Kaye (personal statement), Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

Addressing some of these comments would entail a significant amount of work and cost, and are nonetheless outside of the purview of Commission Orders. Absent Commission directives, we do not plan to address them. We have, however, addressed the remaining issues through our revised modeling analysis process (which is detailed in Chapter 3: Analysis Approach).

5. PSIP Generation Resources

Party Comments

Almost all responding Parties submit that low-cost, grid-scale, and customer generated renewable energy should first be pursued aggressively and optimized as foundational elements of a 100% renewable future. This renewable energy includes PV, DER (including "smart" DERs), wind, geothermal, and hydro as well as energy storage, energy efficiencies, DR, and fuels such as biomass (including biofuels). In other words, a diversified portfolio of renewable generation that precludes and displaces fossil-fuel fired generation.

All other current and proposed fossil generation and generating units should be limited by the incorporation of this renewable energy into the PSIP resource plans. Unit deactivation plans, PPA terminations, and replacement fossil generation additions and retrofits (such as for LNG and the proposed Kahe 3x1 combined cycle plant) must all be considered against this aggressive renewable energy future. Analysis should include a safety valve (load bank) to control excess energy risks, reduce down reserves, and reduce curtailment of renewable resources.

The methodology for creating this energy future must be fully transparent and impartial, properly assess and value all generation options, defer and minimize capital expenditures, be competitively bid, fully identify the locations for siting all replacement generation and fully consider the cultural, environmental, and social impacts, assess the impacts on grid reliability and system security and implement appropriate measures to adequately address both, fully identify and address all financial implications and customer bill impacts, evaluate and address the tradeoffs between fossil and renewable generation, and consider customer preferences.

Parties Issuing These Comments

County of Hawai'i, County of Maui, DBEDT, AES Hawai'i, Blue Planet, DERC, Hawai'i Gas, HPVC, HREA, HSEA, Paniolo Power, Sally Kaye (personal statement), Sierra Club, SunPower, TASC, Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

Our directive is to develop a PSIP that provides "useful context and meaningful analysis to inform major resource acquisition and system operation decisions, and identify well-reasoned and adequately-supported plans and actions that will result in reliable energy services, meeting State clean energy requirements, while ensuring that costs and rates will be reasonable."[49] Our modeling tools select the resources and timing to achieve this directive. Renewable generation will be foundational to that plan, and will be implemented in a manner that best achieves our directive.

[49] Order No. 33877; *op. cit.*, at 7.

6. Capacity Expansion Modeling Tools

Party Comments

The comments for responding Parties are summarized as follows.

The RESOLVE and SWITCH capacity expansion models should be run simultaneously to model the costs and benefits of an increased pace for adopting renewable generation. The results of these models should then be compared, divergent results assessed, and a consistency established for creating an optimized resource plan. As an alternative, review the modeling and assumptions used by RESOLVE, indicate how SWITCH can supplement and improve RESOLVE, and ensure that RESOLVE is used transparently.

RESOLVE inputs should be free of artificial constraints, have its assumptions corrected or supplemented (such as the current unit deactivation schedule), include a more comprehensive analysis of the volatility of oil and LNG prices, and include a reference case for comparison's sake.

The process should embody real and substantial stakeholder participation and input. The Parties should be allowed to submit a limited number of information requests (IRs).

The results from the RESOLVE and SWITCH modeling and analysis should enable the Commission to evaluate each alternative resource plan, identify key factors, and make informed decisions for implementing each plan, especially over the next five years.

Parties Issuing These Comments

County of Maui, DBEDT, Consumer Advocate, AES Hawai'i, Blue Planet, DERC, Hawai'i Gas, HPVC, HREA, HSEA, Paniolo Power, Sierra Club, SunPower, TASC, and Ulupono.

Our Action Regarding this Topic

E3's analysis using RESOLVE was developed independently without input from the Companies. RESOLVE used only the resource cost and fuel price forecast assumptions that we posted to our FTP (WebDAV) site. An E3-written report describing how the RESOLVE modeling tool was employed in developing the December 2016 PSIP can be found in Appendix P: Consultant Reports. The FTP (WebDAV) site contains all the inputs necessary for the Parties to fulfill their own request: using the SWITCH model to conduct their own independent modeling and analysis to develop independent resource plans.

7. Interisland Transmission

Party Comments

The comments for the responding Parties are summarized as follows.

Any interisland transmission analysis must be considered against pertinent renewable alternatives for O‘ahu, including distributed energy storage systems (DESS) and battery energy storage systems (BESS)—using an adjusted value approach— as well as offshore wind. Interisland transmission should also be analyzed as creating a potential statewide grid through a comprehensive or selective two-way cable system among various islands. One general public commenter contends that O‘ahu can generate all of its energy needs from renewable resources, thus making moot the need for interisland transmission.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sally Kaye (personal statement), Sierra Club, and Ulupono.

Our Action Regarding this Topic

Before analyzing interisland transmission, we requested NREL to update their studies on O‘ahu's renewable resource potential, and quantify the amount of offshore wind resources needed to potentially achieve 100% renewable generation on-island. (These reports are presented in Appendix F: NREL Reports.) In addition, E3 has run sensitivity analysis using the significantly higher resource potentials provided by Dr. Fripp. Our analysis incorporates our High-DER forecast, which assumes that all single family residential and 20 to 25% of commercial customers are net-zero where DG-PV production is equivalent to consumption. We are also in discussions with Google and Mapdwell to refine the technical potential of DG-PV using their high resolution satellite imagery and 3D modelling work.

With this information at hand, E3 analyzed available alternatives including interisland transmission. The results of this analysis can be found in "Interisland Transmission Copper-plate Plans" in Chapter 3: Analytical Approach.

8. Fuels and Forecasts

Party Comments

Hawai‘i Gas provided "alternative LNG prices"—correlating with the EIA AEO and STEO fuel forecasts used in the *PSIP Update Report: April 2016*—requesting their use in further PSIP analysis. Ulupono contends that the EIA AEO and STEO fuel forecasts are artificially low and highly volatile. As such, they should only be used in short-term (up to two years) analysis and evaluated, explicitly quantified, and assessed against the hedge offered by renewable resources to garner their true impact on planning.

Parties Issuing These Comments

Hawai‘i Gas and Ulupono.

Our Action Regarding this Topic

We fully understand that fuel prices and fuel price forecasts are volatile, and change over time. For our April PSIP, we relied on fuel price forecasts developed using the STEO forecast. We were attempting to demonstrate the impact of lower fuel prices on the resource plans to better understand whether LNG would still be cost effective with lower petroleum prices. We did this because EIA had yet to publish its 2016 Annual Energy Outlook (AEO) containing fuel price forecasts, and we didn't want to rely on the 2015 AEO forecast because those prices were significantly higher the 2016 actual pricing, and would have painted an inaccurate picture.

For our December 2016 PSIP, we updated our fuel price forecasts to incorporate the forecasts from the 2016 EIA Annual Energy Outlook. In addition, E3 has completed sensitivity analyses evaluating the hedge value of renewable energy (as requested by Ulupono) and the LNG fuel price forecast provided by Hawai‘i Gas.

9. DER and DG-PV

Party Comments

A majority of the responding Parties state that DER and DG-PV can provide a number of cost competitive benefits to customers and the electric grid. The PSIP analysis should:

- Integrate more DG-PV.
- Include emerging and expanded DER approaches, methodologies, and devices.
- Include smart-supply DERs.
- Consider both as increasing resources.
- Be quantified against other renewable and fossil-fuel investments.
- Examine the benefits of DER in providing ancillary services.
- Consider alternative and non-capital DER configurations to address integration and interconnection costs and to relieve system constraints.

Essentially, the PSIP analysis should treat DER and DG-PV as resources to be maximized.

Parties Issuing These Comments

County of Maui, DBEDT, Blue Planet, DERC, Hawai‘i Gas, HPVC, HREA, Paniolo Power, Sierra Club, TASC, and Ulupono.

Our Action Regarding this Topic

Our analysis does consider both the Market DG-PV and High DG-PV forecasts: for O‘ahu approximately 1,300 MW of market level DG-PV and approximately 2,100 MW of high forecast DG-PV. Market DG-PV is based on expected customer response to market pricing; High DG-PV includes all single-family residential customers and 20–25% of total commercial sales (assuming rooftop space constraints and challenges arising from property ownership). Our analysis has also considered increasing levels of DR and ultimately incorporated the High DER forecast into the resource plans. (See "DG-PV Energy Sales Forecasts" in Appendix J: Modeling Assumptions Data for DG-PV forecasts for all islands we serve.)

In addition, our analysis accounts for all interconnection and integration costs (which we fully describe in Appendix N: Integrating DG-PV on Our Circuits). Although we believe that our high DER assumptions provide a good high DG-PV penetration boundary for analysis of future situations, we are in discussions with Google and Mapdwell to better understand the technical potential of DG-PV using their high resolution satellite imagery and 3-D modeling work.

At the Technical Conferences and Stakeholder Conferences, we received input that another method is to estimate high forecast DG-PV based on available rooftop space. Performing a detailed investigation and analysis on this input would take some time to arrive at a reasonably accurate forecast. As such, we have taken this input as an action item to be performed for the next iteration of the PSIP.

While Party input hasn't stated a maximize level of market DG-PV, one Party (Ulupono, the only Party submitting input related to DER) has stated the expected high DG-PV forecast to be approximately 3,000 MW.

10. Liquefied Natural Gas (LNG)

Party Comments

About half the responding Parties feel that the Companies should immediately withdraw its three LNG-related applications, abandoning their plan to source LNG directly and, instead, collaborate with Hawai‘i Gas to import the fuel. Hawai‘i Gas, in its Order No. 33740 filing, presented a comprehensive plan (including adjusting its pricing structure to conform with those of the Companies) for such a collaboration.

Any resultant resource plan must thoroughly assess the risks and costs associated with importing and distributing LNG, including converting current generation units to burn LNG. In addition, the Parties request an assessment of what could be achieved by investing this sum entirely in a renewable generation infrastructure.

Parties Issuing These Comments

County of Maui, Consumer Advocate, AES Hawai‘i, Blue Planet, DERC, Hawai‘i Gas, HREA, HSEA, Paniolo Power, Sierra Club, Ulupono, and general public comments.

Our Action Regarding this Topic

As a direct result of the Commission’s dismissal of NextEra Energy’s application to acquire the Hawaiian Electric Companies and NextEra’s subsequent withdrawal from the PSIP docket, we have withdrawn our three LNG-related applications. All of these applications were predicated on NextEra’s direct involvement.

As indicated in our Motion for Clarification and our PSIP Work Plan, LNG is not included in the near-term action plan, but we have analyzed and included these analyses over the long-term with LNG in the December 2016 PSIP update to determine LNG’s impact in stabilizing and lowering costs for customers and in lowering emissions while aiding in the effective integration of more renewable energy.

11. Renewable Energy on O‘ahu

Party Comments

Several of the responding Parties commented on the various renewable resources included in the *PSIP Update Report: April 2016* for attaining 100% renewable generation on O‘ahu. These Parties stated that offshore wind must be reconciled with the Bureau of Ocean Energy Management’s (BOEM) efforts to lease offshore wind sites. The benefits and costs of onshore and offshore renewable generation options should be compared and contrasted with those of interisland transmission.

A general public commenter questioned the assumption that O‘ahu could not generate 100% of its energy needs from current renewable resources. Life of the Land, citing two EPRI studies, suggested that O‘ahu could obtain all of its renewable generation needs through current ocean wave energy technology.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Life of the Land, Paniolo Power, Puno Pono, Sally Kaye (personal statement), Sierra Club, and Ulupono.

Our Action Regarding this Topic

We have incorporated the revised resource potential provided by NREL into our analysis. To be feasible, all renewable technologies must exhibit fundamental attributes (further discussed in Appendix E: New Resource Options):

- Sound engineering design concepts.
- Commercial availability from a reputable vendor who can fully support the performance and servicing of the technology (including all balance of plant items) over its useful life.
- Demonstrated financial feasibility of a project employing the technology, including its benefits to customers, system needs, and integration costs—all of which would be stated in a competitive bidding process or waiver from same approved by the Commission.
- Ability of the project sponsor to demonstrate the financial wherewithal and technical capabilities to successfully finance, construct, and operate the project employing the technology.

Renewable generation options for O‘ahu is thoroughly discussed in Appendix H: Renewable Resource Options for O‘ahu. Additional information on these resources can be found in the following sections:

Grid-Scale Wind and Grid-Scale PV. Appendix F: NREL Reports fully discussed the possibilities, potential, and realities of on-island grid-scale PV and grid-scale wind on O‘ahu. Bottom line: while a theoretical maximum potential exists, the feasibility of realizing this maximum is much less certain.

Offshore Floating Platform Wind. Appendix H: Renewable Resource Options for O‘ahu fully discusses the potential and realities of this promising renewable resource. We remain engaged in BOEM’s leasing process and continue to monitor the overall viability of offshore wind for O‘ahu.

Interisland Transmission. See “Interisland Transmission” in Chapter 2: Commission Directives for a discussion about the analysis of interisland transmission among O‘ahu, Maui, and Hawai‘i Island. See “Interisland Transmission Copper-plate Plans” in Chapter 3: Analytical Approach for a discussion of the resources and results of E3’s interisland transmission analysis.

Hydrokinetic Energy. Ocean energy technologies are currently not feasible, nor do they appear to be in the near-future. See “Ocean Energy Technologies” on page B-46 for a rational discussion of these emerging technologies.

The combined results of our analysis appears in our near-term action plans, which detail how we plan to attain 100% renewable energy on O‘ahu.

E3 has also analyzed the higher onshore resource potentials provided by Dr. Fripp. Our long-range plans are completely flexible and open to multiple pathways for achieving 100% renewable energy; our near-term action plan does not preclude any future pathway, including new emerging technologies.

12. Microgrids

Party Comments

Half of the responding Parties state that the PSIP analysis should give greater consideration to microgrids, especially comparing their performance to the cost of grid services. Two Parties feel that integrated energy districts (microgrids)—should also be required for communities with health facilities for life, safety, and security.

Parties Issuing These Comments

County of Hawai‘i, County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sierra Club, and Ulupono.

Our Action Regarding this Topic

A microgrid can be considered as a non-transmission alternative (NTA) to conventional transmission and distribution. There is a growing and important role for distributed sites to enhance energy resiliency and security—which we fully intend to exploit. Microgrids, including those on military sites interconnected and complementing the electric grid, can:

- Provide resiliency and energy security for all our customers by using diversified locations for firm generation.
- Provide enhanced energy resiliency and security on military bases that are key to national defense and emergency or disaster response. These bases house airfields, ports, logistics, labor force, and housing necessary for major humanitarian response missions.
- Help ensure our ability to support core military missions, which are a key sector of our economy.

Three microgrids are currently in the plans for O‘ahu’s electric grid. The Schofield Barracks Generating Station, which broke ground on August 22, 2016, will contribute 50 MW to the grid and enhance our ability to integrate more renewable generation. We plan to design, permit, finance, build, own, operate, and lease at little to no cost, a new 54 MW generating station located on the Marine Corps Base Hawai‘i site in Kaneohe. We are also considering two concepts at Joint Base Pearl Harbor-Hickam: a 90 MW microgrid on base or a 100 MW power barge at the Waiau Generating Station that could be interconnected to the base from that site or temporarily relocated to the base under emergency conditions. The Airport Dispatchable Standby Generation (DSG) unit, scheduled for completion in early 2017, offers 8 MW of emergency generation for the airport and limited duty dispatchable generation for the O‘ahu grid. (See Appendix D: Current Generation Portfolios for descriptions of these projects.)

The Queens Medical Center, with the only Level 2 Trauma Center in the Pacific, is also equipped with sufficient distributed generation to operate its Punchbowl campus as a microgrid. The Companies strongly supported this microgrid project.

13. Energy Storage

Party Comments

The Parties who signed the Annex A letter (see page B-70) expressed concern about a number of issues around battery energy storage and related information used in future analysis. Their concerns include:

- Adjusting forecasts for an increase (rather than a decrease) in distributed energy storage systems and accounting for their use in localized reliability and security.
- Thoroughly considering a wider array of energy storage options (such as hydrogen storage and thermal distributed storage), including its financial impact.
- Assessing energy storage’s value to ancillary services, over-generation, circuit-level issues, and operational flexibility (such as flexing the load curve, capturing excess energy, and shifting peak load).
- Updating the outdated, insufficient, and inaccurately high costs and amounts of energy storage.
- Comparing and contrasting the value of energy storage against interisland transmission.

The County of Maui suggested a specific situation to analyze: hardwiring a near-term market disruption from distributed energy storage systems, then iterate by modeling TASC’s dynamic resistive frequency control approach.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sierra Club, and Ulupono.

Our Action Regarding this Topic

As we stated in our response to "11. Renewable Energy on O'ahu" (page B-104), we are only including currently viable technologies in our modeling analysis, which includes their current operational capabilities. As yet, this does not include technologies such as hydrogen storage and thermal distributed storage. Our "least regrets" near-term action plan is one where our long-range plans are completely flexible, so should this technology become cost-effective in the future, we can incorporate this—or any new technology—when appropriate.

14. Utility Ownership

Party Comments

Most of the responding Parties contend that the *PSIP Update Report: April 2016* suffers systemic deficiencies because of its main focus on preserving a traditional utility-centric business model, continued utility-owned new generation and utility capital spending, and a dependence on the NextEra acquisition. These Parties, instead, prefer a PSIP that embraces a customer-focused model, opening the possibilities to other types of resource ownership. All new generation options must be owner agnostic, cost-effective, and competitively bid. As such, planning and analysis should be separated from ownership issues.

Parties Issuing These Comments

County of Maui, Consumer Advocate, AES Hawai'i, Blue Planet, DERC, HPVC, HREA, HSEA, Paniolo Power, Sally Kaye (personal statement), Sierra Club, SunPower, TASC, Tawhiri Power, and Ulupono.

Our Action Regarding this Topic

The December 2016 PSIP update relies on owner agnostic generation options for its near-term action plans, except in special circumstances such as with the Department of Defense. Even in those special circumstances, construction for any utility-owned generation would, of course, be competitively bid and sources.

15. Customer Retention Economics

Party Comments

Several of the responding Parties state that the PSIP should recognize the value of keeping customers connected to the grid, and therefore should include an analysis for the potential and implications of customer retention economics, and present a substantial plan to encourage customers staying connected.

Parties Issuing These Comments

County of Maui, Blue Planet, DERC, Hawai‘i Gas, HREA, Paniolo Power, Sierra Club, and Ulupono.

Our Action Regarding this Topic

We fully understand and appreciate the importance of keeping customers connected to the electric grid. Customer exit results in reduced DG-PV capacity adversely affecting renewable generation on the grid, and ultimately raises prices to remaining customers. In addition, self-generating customers are not required to comply with state renewable generation goals. See Appendix Q: Customer Retention Economics for a discussion of this topic.

THIRD STAKEHOLDER CONFERENCE: JUNE 29, 2016

In response to comments received from our May 17, 2016 conference, we convened a Third Stakeholder Conference on June 29, 2016. We sent the following email to the Parties and other stakeholders informing them about this upcoming conference.

> Sent: Wednesday, June 01, 2016 5:48 PM
>
> Subject: PSIP Stakeholder Conference
>
> Aloha,
>
> Thank you for providing us your input to our forward-going PSIP work. We have reviewed input and feedback provided by several parties and would like to schedule a follow-up Stakeholder Conference. We are currently working on the logistics for the Stakeholder Conference and will provide a follow up email next week providing the date, time, and location once the details have been worked out. Thank you for your patience.
>
> Mahalo,
> Todd Kanja
> PSIP Lead

A little over a week later, we confirmed the date and time with this email.

> Sent: Friday, June 10, 2016 at 01:39
>
> Subject: PSIP Stakeholder Conference
>
> Aloha,
>
> Please be advised that the Hawaiian Electric Companies will hold a PSIP Update Stakeholder Conference on **Wednesday, June 29, 2016 from 10 am–3 pm**. Additional details, along with the meeting location and agenda for the conference, will follow.
>
> Mahalo,
> Todd Kanja
> PSIP Project Lead

Five days hence, we emailed the Parties, and other stakeholders, and the Commission about the format of the conference and inviting them to present their input in a formal presentation.

> Sent: Wednesday, June 15, 2016 at 15:15
>
> Subject: PSIP Stakeholder Conference
>
> Sending on behalf of Colton Ching, Vice President of Energy Delivery
>
> Aloha,
>
> Thank you for your continued participation in our Power Supply Improvement Plan (PSIP) planning process. Based on comments received from our May 17, 2016 Stakeholder Conference and May

> 31, 2016 request for Stakeholder input, we have scheduled a follow-up Stakeholder Conference on Wednesday, June 29, 2016, from 10:00 am to 3:00 pm. We are reaching out to you with some additional details for this conference, whose emphasis will be to provide Stakeholders an opportunity to provide input in the form of a formal presentation.
>
> As noted in our June 9, 2016 email, we are planning to start the meeting at 10:00 am and end it at 3:00 pm. We are planning to have a morning session (10:00 am–12:00 pm) and afternoon session (1:00 pm–3:00 pm) with a 1 hour break for lunch (on your own). In order to allow everyone an opportunity to participate in the meeting, we ask that presentations be kept to a maximum of 15 minutes and related to our forward-going work as described in Chapter 9 "Next Steps" of the PSIP Update Report: April 2016. We will adjust the agenda according to the amount of presentations we receive.
>
> If you plan to use slides or other visuals for your presentation, please send the electronic files by 12:00 pm, MONDAY, JUNE 27, 2016 to us at the email address provided below. Please note that this opportunity to present is optional and that there is no requirement that you prepare a presentation. If you wish to distribute hard copies to the stakeholders, please bring at least 30 copies.
>
> Although space remains limited, we will do our best to accommodate two representatives per organization to attend in person. In addition, we will also allow for participation via telephone conference. Unfortunately, the conference bridge does have limits, and for that reason, we will need to prioritize those who do not have a representative attending in person. We thank you for your understanding.
>
> If your organization wishes to attend this meeting, please RSVP no later than 12:00 pm, MONDAY, JUNE 27, 2016 to Heather Villamil. Her contact information is below. Please indicate who will be representing your organization. If you are unable to attend in person, please inform us if you will be participating via telephone conference and the name of the individual who will be calling in.
>
> RSVP to:
> Heather Villamil
> (808) 543-5820
> heather.villamil@hawaiianelectric.com
>
> We are still working to secure a Hawaiian Electric meeting room in Downtown Honolulu for the conference and will let you know as soon as we have one. We look forward to seeing you at this meeting.
>
> Mahalo,
> Colton Ching

On June 25, 2016, we sent an email to the Parties, stakeholders, and the Commission detailing the specifics for the conference. Attached was an Excel file containing the revised new generation assumptions.

> Sent: Saturday, June 25, 2016 at 00:35
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference
>
> Sending on behalf of Colton Ching, Vice President of Energy Delivery
>
> Aloha, Parties to Docket No. 2014-0183,

As a follow-up to our June 15, 2016 email, we would like to provide additional details about our upcoming PSIP Stakeholder Conference.

- Date, Time, Location: The Conference will be held on Wednesday, June 29, 2016, from 10:00 am to 3:00 pm, in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu. Parking validation will not be provided for this event. Our building that houses the auditorium is a secured facility and a government issued ID is required for entry. Please arrive early to allow time for check in with the security guard (once you present your ID, you will receive a visitor badge).
- Purpose, Format: The purpose of this Conference is to provide Docket Parties with an opportunity to offer input in the form of a formal presentation. Like prior conferences, the Department of Business, Economic Development, and Tourism has agreed to moderate these discussions to facilitate open and constructive dialogue. To that end, the conversations that take place at this Conference are intended to be informal and not part of the official record in this docket.
- Ground Rules: As with the previous Conferences, we ask that no recording devices of any kind (video or audio) be used. Other ground rules are:
  - Listen and be open to all ideas
  - Always engage assuming no malicious intent, process is intended to be collaborative among the parties
  - Try to provide supporting facts/data whenever possible when making comments
  - Please silence all cell phones to avoid disrupting others
  - All dialogue should be directed through the facilitator
  - Leave preconceptions outside of the Conference
  - Avoid sidebar conversations so the stakeholders can remain engaged
  - Honor time limits so everyone has an opportunity to voice their thoughts

  Your acceptance of this invitation indicates your acceptance of these conditions.
- Presentations and Inputs: The Conference will consist of presentations by interested Parties, followed by a brief presentation by E3 describing our planned work on continued analysis of interisland transmission. We are planning to have a morning session (10:00 am–12:00 pm) and an afternoon session (1:00 pm–3:00 pm) with a 1-hour break for lunch (on your own). In order to allow everyone an opportunity to participate in the meeting, we ask that presentations be kept to a maximum of 15 minutes and related to our forward-going work as described in Chapter 9 "Next Steps" of the PSIP Update Report: April 2016. If you wish to provide resource information, we ask that the information be provided in the same format as our updated resource information, which is attached for your reference. We will adjust the agenda according to the amount of presentations we receive.

  As a friendly reminder, if you plan to provide a presentation at this Conference, please send the electronic files by 12:00 pm, MONDAY, JUNE 27, 2016 to us at the email address of Heather Villamil provided below. Please note that this opportunity to present is optional and that there is no requirement that you prepare a presentation. If you wish to distribute hard copies to the attendees, please bring at least 30 copies.

- Participation In Person and via Teleconference: Although space remains limited, we will do our best to accommodate two representatives per organization to attend in person. In addition, we will also allow for participation via telephone conference. Unfortunately, the conference bridge does have limits, and for that reason, we will need to prioritize those who do not have a representative attending in person. We thank you for your understanding.
- RSVP: If your organization wishes to attend this Conference, please RSVP no later than 12:00 pm, MONDAY, JUNE 27, 2016 to Heather Villamil. Her contact information is below. Please indicate who will be representing your organization, as only those who RSVP and are on the guest list will be allowed to check in. If you are unable to attend in person, please inform us if you will be participating via telephone conference and the name of the individual who will be calling in.

  RSVP to:
  Heather Villamil
  (808) 543-5820
  heather.villamil@hawaiianelectric.com

We look forward to seeing you at this Conference.

Mahalo,
Colton Ching

Two days later, we again emailed the Parties, stakeholders, and Commission with the conference agenda, and attached the PSIP fuel price forecasts for our three operating utilities that we were using in our current analysis.

Sent: Tuesday, June 27, 2016 at 01:41

Subject: Hawaiian Electric PSIP Stakeholder Conference

Sending on behalf of Colton Ching, Vice President of Energy Delivery

Aloha, Parties to Docket No. 2014-0183,

Based on the responses we have received to present as of 4:00 PM today, we have set the agenda for Wednesday's PSIP Stakeholder Conference.

Agenda

Introduction – 10:00 AM to 10:15 AM

Morning Session – 10:15 AM to 11:45 AM
1. E3 – Interisland Transmission Scope Presentation
2. DBEDT Presentation

Lunch (On your own) Break – 11:45 AM to 12:45 PM

Afternoon Session – 12:45 PM to 3:00 PM
1. Recap of Morning Session (DBEDT)
2. Ulupono Initiative Presentation
3. TASC Presentation
4. Hawaiian Electric Presentation

Reminders

The Conference will be held on Wednesday, June 29, 2016, from 10:00 am to 3:00 pm (Lunch on your own from 11:45 AM-12:45 PM), in the King Street Auditorium at the Hawaiian Electric Company headquarters building located at 900 Richards Street in downtown Honolulu. Parking validation will not be provided for this event. Our building that houses the auditorium is a secured facility and a government issued ID is required for entry. Please arrive early to allow time for check in with the security guard (once you present your ID, you will receive a visitor badge). The security guard will allow entry to those parties who RSVP'd and are on the guest list.

Ground Rules: As with the previous Conferences, we ask that no recording devices of any kind (video or audio) be used. Other ground rules are:

- Chatham House Rules apply (participants are free to use the information received, but neither the identity nor the affiliation of the speaker (s), nor that of any other participant, may be revealed)
- Listen and be open to all ideas
- Always engage assuming no malicious intent, process is intended to be collaborative among the parties
- Try to provide supporting facts/data whenever possible when making comments
- Please silence all cell phones to avoid disrupting others
- All dialogue should be directed through the facilitator
- Leave preconceptions outside of the Conference
- Avoid sidebar conversations so the stakeholders can remain engaged
- Honor time limits so everyone has an opportunity to voice their thoughts

Your acceptance of this invitation indicates your acceptance of these conditions.

- Updated Fuel Price Forecasts utilizing the EIA Annual Energy Outlook 2016 Early Release (Reference) are attached for your reference. Please note that these forecasts have been posted to the PSIP WebDAV site.

We look forward to seeing you at this Conference.

Mahalo,
Colton Ching

The day before the conference, we emailed a revised agenda.

Sent: Tuesday, June 28, 2016 at 23:13

Subject: Hawaiian Electric PSIP Stakeholder Conference

Aloha,

Please note that tomorrow's agenda has been revised as noted below.

Revised Agenda

Introduction – 10:00 AM to 10:15 AM

Morning Session - 10:15 AM to 11:45 AM
1. Blue Planet Presentation
2. TASC Presentation
3. DBEDT Presentation

> Lunch (On your own) Break - 11:45 AM to 12:45 PM
>
> Afternoon Session – 12:45 PM to 3:00 PM
> 1. Recap of Morning Session
> 2. Ulupono Initiative Presentation
> 3. E3 – Interisland Transmission Scope Presentation
> 4. Hawaiian Electric Presentation
>
> Thank you,
> Todd

In response to a Party member request, we emailed all invited stakeholders with attachments of the presentations listed on the agenda.

The evening after the meeting concluded, we emailed conference participants with a summary of the proceedings, a call for additional input, all the presentations attached (again), and an Excel file attached (again) containing our new generation assumptions to be used as a format for subsequent input from the Parties.

> Sent: Wednesday, June 29, 2016 7:25 PM
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference
>
> Sent on behalf of Colton Ching, Vice President of Energy Delivery
>
> Aloha, Parties to Docket No. 2014-0183,
>
> Thank you for your participation in yesterday's (sic-today's) stakeholder conference! We are especially grateful to Dr. Matthias Fripp, Steven Rymsha, Chris Yunker, Kyle Datta, Jerry Sumida, and Jeremy Hargreaves for taking the time to develop and share their presentations, and to Mark Glick once again for his leadership in facilitating the group's discussion. Since the presentations were sent out over multiple emails leading up to the stakeholder conference, we are attaching all of them here once more for your convenience.
>
> As stated during my presentation, we welcome additional inputs for our analyses by Wednesday, July 6, 2016. If you wish to offer resource information, please provide it in the same format as our updated resource information, which is attached for your reference (see Excel file), and send it to Todd Kanja, Hawaiian Electric's Project Lead for the PSIP Update. Todd can be reached at: todd.kanja@hawaiianelectric.com and (808) 543-4329.
>
> Mahalo!
> Colton Ching

Two days later, we emailed the Parties the revised NREL report included in our *PSIP Update Report: April 2016*, pointing out the pages and maps that were being revised.

> Sent: Friday, July 1, 2016 at 13:31
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference
>
> Aloha,
>
> As a follow-up to discussion regarding the NREL resource potentials during yesterday's Stakeholder Conference, we wanted to clarify that the grid-scale onshore wind potential and grid-scale solar PV

> potentials for the islands of Hawai'i, Maui, and O'ahu can be found in Appendix F, pages F-24 and F-25. These are the resource potentials used in the preferred plans. We would also like to note that the Utility Scale PV Development Potential Maps on pages F-39 through F-46 are not correct and will be updated. We will ask NREL to update these Development Potential Maps to match with data provided on pages F-24 and F-25.
>
> Mahalo,
> Todd

On July 5, 2016, we sent our final email to the Parties concerning the conference. In it, we attached our notes from the conference's proceedings and the revised NREL report.

> Sent: Tuesday, July 5, 2016 at 15:47
>
> Subject: Hawaiian Electric PSIP Stakeholder Conference - Flip Chart Notes and Corrected NREL report
>
> Aloha,
>
> Hope you all had a safe and enjoyable 4th of July weekend! As a follow-up to last week's PSIP Stakeholder Conference and June 30 (sic), 2016 email, please find attached 1) Flip Chart Notes from the conference and 2) updated NREL resource potential report with corrected pages F-39 through F-46. As a friendly reminder, if you would like to submit resource cost information, please do so by July 6, 2016. We ask that the information be provided in the same format as the resource cost information spreadsheets provided in our June 24, 2016 and June 27, 2016 emails.
>
> Mahalo,
> Todd

Conference Proceedings: Third Stakeholder Conference

Colton Ching, Vice President of Energy Delivery at the Hawaiian Electric Companies, introduced Mark Glick from DBEDT who would be moderating the conference. Mr. Ching that the Companies would be assessing cost information received from SunPower and Hawai'i Gas, as well as all the comments and input received as a result of our May 17, 2016 conference and Order No. 33740.

Mr. Glick began by stating his appreciation for this conference so that the Parties could comment and provide feedback to any outstanding issues. We expect to come up with an optimized analysis that creates the lowest cost plan that explores DER and storage. Mr. Glick then introduced the people and organizations giving presentations.

After the lunch break, Mr. Glick summarized the proceedings from the morning, reviewing each of the three presentations and providing some overall comments about the task of creating a Power Supply Improvement Plan.

Presentations: Third Stakeholder Conference

This section summarizes the main point from the presentations given at the Third Stakeholder Conference.

Blue Planet

Dr. Matthias Fripp, University of Hawai‘i Manoa, presented on behalf of Blue Planet (see page B-188 for the slides). He made these points during his presentation:

- The iterative process for creating and validating the assumptions used for analysis needs greater transparency, such as a technical committee to vet the data.
- Multiple models (such as SWITCH and RESOLVE) should be run to provide different perspectives and allow for richer results.
- The risk and uncertainty of customer rates needs more analysis, especially when comparing long- and short-term costs, the resultant savings from both, and their relative stability.
- NREL’s assumption of 500–600 MW potential for grid-scale solar on O‘ahu pales in comparison to our estimates.
- Agreement among the Companies and the Parties is needed to effectively handle uncertainty and cost projections.

TASC

Steve Rymsha presented on behalf of TASC (see page B-192 for the slides). He made these points during his presentation:

- Incorporate renewable spinning reserve, smart homes, and flywheels or bulk energy storage to the modeling analysis.
- Model distributed load banks and their locations as a means to not change current generation resources or grid infrastructure.
- Pilot the strategy being employed on Tasmania (two 1.5 MW systems) using load banks by starting with Moloka‘i and determining how it can be expanded to other islands.
- Rather than curtailing, allow energy to flow onto the grid by employing substations with resistive response capabilities.

DBEDT

Chris Yunker presented on behalf of DBEDT (see page B-196 for the slides). He made these points during his presentation:

- Consider cost, reliability, social impacts, and island-specific resources in the interisland transmission analysis at a high level first to better avoid excess analysis paralysis; analyze further the impact and cost of cable configurations and redundancy that are critical to reliability; and analyze the impact on terminus grids.

- Compare and contrast the viability, desirability, timing, capabilities, and cost of our interisland transmission with those of the much larger mainland examples by engaging the companies involved in their planning and implementation.
- Analyze the baseline system requirements for the 3x1 combined cycle Kahe unit as well as the cost recovery timeframe (including $50 million for early deactivation).
- Initiate the procurement process for renewable generation, together with DER and DR as all need long-term planning to be fully realized. Use models to analyze the potential for various renewable options.
- Consider the future prospects for energy storage (see the related Navigant study).

Ulupono

Kyle Datta presented on behalf of Ulupono (see page B-202 for the slides). He made these points during his presentation:

- Model battery energy storage earlier in the preferred plans, especially when planning to attain the 30% and 40% RPS scenarios.
- Review the plan's costs (especially transmission costs) which appear too low compared to other's analysis, and do not include customer service costs.
- Model the impact of integrating 100% renewables earlier in the planning period.
- Analyze the risk of the stranded costs of grid-scale solar versus DG-PV.
- The costs for installing and operating grid-scale solar must be closely monitored to ensure their lower costs when compared to continued DER installations.

E3 (Energy and Environmental Economics)

Ren Orans and Ana Mileva presented on behalf of E3 (see page B-205 for the slides). They made these points during their presentation:

- Interisland transmission analysis includes cost, redundancy decisions, individual island reserve constraints, and resultant benefits from different configurations. Other issues to analyze include the maximum benefits and their related costs, depth and path of the cable, available resources on Maui and Hawai'i Island including siting locations and grid connections, and grid upgrades necessary for a cable interconnection (especially Hawai'i Island). A thorough market and development feasibility study must be conducted.
- Curtailed renewables should offer reserves, and could be eliminated with storage or with better control (although that must be assessed).

- NREL's resource potential for O'ahu needs further analysis to better understand their outcomes and benefits across all islands.
- Advanced storage, including hydrogen, can be modeled. Hydrogen, however, has an extremely large draw on renewable generation, must be optimized in wind and seasonally, and can affect spinning reserves.
- Renewable resources for each island must be identified and located using potential resource studies and NREL studies that include high-level maps, including detailed community work necessary to site resources.

Hawaiian Electric

Colton Ching presented on behalf of the Companies (see page B-218 for the slides). He began by reviewing the timeline for the PSIP Update beginning with November 2015 and carrying through September 2016. Mr. Ching:

- Summarized the energy storage and PV cost information received from SunPower and the LNG forecast and supplier from Hawai'i Gas.
- Displayed graphs that compared the PSIP Update cost assumptions for PV and energy storage with those provided by SunPower, and discussed how these differences would be analyzed.
- Presented the next steps for the Companies in continuing to update our PSIP, focusing on an updated analysis with new fuel price forecasts and resource cost assumptions, additional system security analyses, interisland transmission, and offshore wind, plus additional risk premium stochastic analysis and sub-hourly analysis.
- Stated September 30, 2016 as the revised filing date.

Action items: Third Stakeholder Conference

The following action items were identified at the Third Stakeholder Conference:

- E3 will distribute its assumptions and inputs, including how their model operates (through the FTP site currently being used to distribute information to the Parties) so long as it doesn't contain proprietary information.
- The Companies will cite the NREL reference in the upcoming PSIP filing, and will conduct a sensitivity analysis to compare our PV costs assumptions against those presented by SunPower.
- The Parties will submit any addition input (with source documentation) by July 6, 2016.

TECHNICAL CONFERENCE #1 AND #2

The Commission scheduled two additional conferences, called Technical Conference #1 and Technical Conference #2.

Technical Conference #1: September 21, 2016

In Order No. 33877, the Commission established an updated procedural schedule that included, among a number of directives, the convening of two technical conferences. The purpose of these conferences, chaired by Commission staff, was "to enable the commission to interact directly with the HECO Companies' planning team, and to facilitate the finalizing of the PSIPs."[50] The Commission also invited the Parties to propose questions and suggest alternative modeling inputs, assumptions, methods, and analytical approaches." The Parties responded with over 200 questions and other suggestions for the Commission.

At the conference, the Companies were prepared to respond to each of these questions.

David Parsons, Chief of Policy and Research for the Commission, moderated the meeting. Carl Freedman conducted the meeting. Colton Ching was the main representative for the Company. As directed, all Company consultants and members of the resource planning team attended the conference, either in person or through the conference telephone bridge.

Commission staff and representatives asked all of the questions during the conference, few of which touched on the 200+ Party questions. Mr. Freedman and Mr. Parsons asked the vast majority, with Jay Griffin and Matthew McDonnell contributing a few; little additional guidance was offered. Mr. Ching responded to many questions, with Company staff and outside consultants responding to questions specific to their areas of expertise.

The conference focused on four areas: optimization and overall modeling approach; resource options; ancillary services and system security; and inputs, assumptions, uncertainty, and risk. The conference lasted all day. There were no presentations.

Various representatives of the Companies, including consultants, responded to questions. They:

- Described the modeling process that we published in our Work Plan, and the input assumptions and sensitivities we plan to run in the modeling analysis. They stated

[50] Order No. 33877; *op. cit.* at 32.

that the process for developing the five near-term action plans (one for each island we serve) is integral to the modeling process.

- Reiterated that LNG will not be part of the near-term action plans, but we are modeling its inclusion for long-term planning. As a result, no unit modifications will be undertaken in the near-term.
- Stated that the RESOLVE optimization model is being used for our analysis, and discussed in detail many input assumptions, resources, and other variables being used in the model, and the results that they produce—all of which are being used to develop the updated PSIP.
- Described how the least-cost plan is being developed.
- Explained how DR and DER is being used as inputs to the RESOLVE model to run detailed production simulations to develop retail rates.
- Discussed the roles that DG-PV, curtailment, legacy programs (such as NEM, SIA, and FIT), current programs (CSS and CGS), fuel forecasts (including LNG), energy storage (including pumped storage hydro), grid-scale PV, grid-scale wind, Federal and state energy tax credits, O‘ahu renewable resource potentials, electric vehicles, unit deactivations, IPPs and PPAs, ancillary services, and system security have in our modeling analysis.
- Explained how the PowerSimm Planner modeling tool complements RESOLVE, and is being use to run multiple models for a richer mosaic of potential results.
- Described in detail our system security analysis, its models, its complexity, its depth of analysis, and its consideration of risks and trade-offs.
- Delineated how risk and uncertainty are being addressed and being incorporated systematically, and how a risk premium is being developed for use in our modeling.
- Listed the various stakeholder input that was considered for our analysis, especially input from SunPower, Ulupono and Dr. Fripp, Paniolo Power, and Hawai‘i Gas.
- Explained how we are analyzing customer retention conomics using, in part, the customer update model to determine how it drives behavior

The overall impression was that of a productive meeting.

Technical Conference #2: October 3, 2016

In many respects, this second technical conference mirrored the first. The Parties again submitted about 200 questions, some the same questions because Commission representatives and staff didn’t address them at Technical Conference #1.

As in the previous technical conference, Mr. Parsons moderated, Mr. Freedman ran the conference, and Mr. Ching represented the Company. Commission staff again asked virtually all of the questions; Mr. Ching, Company staff, and outside consultants responded to questions in their areas of expertise.

The meeting began with this prescient announcement from Caroline Ishida, the Commission's Chief Counsel: "…the Commission is considering deferring action on pending G.O. 7 dockets before the Commission pending the outcome of this meeting providing clarity on the PSIP process."

Mr. Parsons began by acknowledging that "long-term resource planning is a challenging and complex process", and that the Companies have integrated "a significant amount of change and best practices" and are continuously improving its modeling and analysis process. He continued by stating a fundamental principle of which we at the Companies are fully cognizant: resource planning is a fundamental responsibility, an essential function of business, and one that must be continuously fulfilled; an ongoing process.

Mr. Parsons continued by expounding and expanding on Commission guidance that the Companies must follow:

- Review and comply with directives in previous Orders.
- Transparently and credibly develop the PSIP and resultant action plans.
- Address Party input and other factors (such as DER, DR, fuel price volatility and risk, and others) with sensitivity analysis.
- Demonstrate how the Companies will stabilize and lower costs to customers, more aggressively seek lower cost renewables, improve the modeling of distributed resources and ancillary services, improve the analysis of fossil fuel generation resources, evaluate the costs of achieving different reliability and system security standards, and squarely address customer implementation risks.
- Develop near-term action plans (potentially updated annually) that map a path forward and form a foundation for longer-term analysis and planning.

As with Technical Conference #1, various representatives of the Companies, including consultants, responded to questions. They:

- Discussed the sensitivities being included in our modeling analysis, adjustments made for smaller sized grids on Lana‘i and Moloka‘i, optimization choices, and how long modeling takes.
- Explained how some system security analysis can be performed simultaneously with the modeling analysis (and hopefully not repeated), but that much must wait for a plan to be complete. Fully conducting system security analysis is a time-consuming process; for instance, it takes at least two weeks to analyze just frequency for each plan.

- Enumerated many of the factors being analyzed in our modeling: interisland transmission, solar and wind resource potential and profiles, DER update, ancillary services, LNG and other fuels, pumped storage hydro, DG-PV, CSS and CGS, transmission and distribution, demand response, as well as many others.
- Explained that, because of Paniolo's outdated input assumptions and forecasts as well as missing information from their Siemens reports, we used other available information to analyze pumped storage hydro.
- Discussed conversations with various Party members about their input.

Commission representatives closed by reiterating some Commission directives. The conference ended early.

STAKEHOLDER MEETINGS

From August through October 2016, we held four meetings with the certain Parties essentially to discuss input assumptions and our modeling analyses process. These meetings were open to all Parties to attend.

First Stakeholder Meeting: August 30, 2016

On August 23, 2016, DBEDT contacted us to schedule a meeting with the Parties in the upcoming weeks. We readily accepted. A two-hour meeting was then scheduled for August 30, 2016.

In an email, Ulupono suggested the following agenda:

1. Purpose of the meeting
2. Understanding the PUC Order
3. How methodology builds on Appendix C
4. How assumptions verification process differs from work to date
5. Hawai'i Island approach
6. Specific workgroups (DER/renewable/fossil/methodology)

There were three attachments to the email: a suggested PSIP methodology, an accompanying flowchart, and an application of the suggested methodology for Hawai'i Island.

The suggested PSIP methodology consisted of four steps. 1. Define the major large-scale infrastructure and policy choices that significantly impact the electrical systems, then develop a matrix to define various possibilities. 2. Convene specific workgroups to develop input assumptions (such as resources, fuels, loads, and capital costs). 3. Iterate a capacity expansion model with system reliability models, DER models, and risk and volatility algorithms to select a least-cost resource plan. 4. Determine the actions that must be implemented over the near-term that best enables the 100% renewable generation goal to be attained.

Representatives from Blue Planet, DBEDT, Hawai'i Gas, Paniolo Power, Sierra Club, and Ulupono, plus Hu Honua, together with representatives from the Companies, attended the meeting. Discussion during the meeting followed the suggested agenda.

The Parties wanted to meet to discuss the work plan we would file on September 7, 2016, and to provide input to our modeling analyses. During the meeting, we discussed the purpose of the PSIP, the potential for the planning process to be collaborative, the purpose of the PSIP proceeding, and the intent of the near-term action plans that are central to the PSIP. We also discussed how capacity expansion modeling builds on the analysis methodologies (described in Appendix C: Analysis Methodologies of our *PSIP Update Report: April 2016*), its advantages, and its shortcomings. Paniolo Power described how the suggested PSIP methodology can be applied to the modeling analysis for Hawai'i Island. A final discussion involved establishing workgroups.

All attendees agreed to schedule another meeting to continue the discussion, especially on the remaining agenda topics.

Second Stakeholder Meeting: September 13, 2016

The influence of hurricanes Madeline and Lester delayed the scheduling of this Second Stakeholder Meeting. The meeting was ultimately scheduled the day before the Parties were required to submit questions in preparation for Technical Conference #1.

The Companies made clear that only representatives attend subsequent stakeholder meetings. We took exception to a representative from Hu Honua being invited and then attending the First Stakeholder Meeting, as well as our not being notified of their attendance. Hu Honua is not an approved participant in PSIP Docket No. 2014-0183, and thus is not beholden to nor required to execute a Protective Agreement as directed in Protective Order No 33588. Hu Honua's attendance hindered an open and candid discussion, and cast a shadow on a collaborative process. The Parties agreed "to err on the side of respect and process" and limit attendance at subsequent meetings to "participants and intervenors".

Attendees at this Second Stakeholder Meeting included representatives from Blue Planet, County of Hawai'i, DBEDT, Paniolo Power, Sierra Club, and Ulupono together with representatives from the Companies. We continued discussing the previous meeting's agenda items.

The meeting focused on the clarity of and a discussion about the modeling analysis process and its input assumptions. The discussion featured representatives from the Companies' consultants E3, Ascend Analytics, and Black & Veatch. The discussion also began scrutinizing various input assumptions, including LNG, DER, DG-PV, energy storage, offshore wind, and electric vehicles. Operational and customer-related risks as well as meeting ancillary service requirements were also discussed.

The discussion began ascertaining that the key points for the Hawai'i Island suggested methodology had been fully covered. Next, we explained how Ascend Analytics would quantify risk by developing a risk premium to iterate in subsequent analysis. The concept of working groups was further explored. The Parties felt that working groups should be formed to develop analysis scenarios, input assumptions, technologies, and specific modeling methodologies for the special issues facing Hawai'i Island and Maui island.

The discourse turned to analyzing the regulatory process, how topics from these meetings could be communicated to the Commission, and how the schedule could potentially be altered. Other topics inquired as to whether we were analyzing load shifting batteries, DER and DR optimization, and interisland transmission; we did.

Everyone agreed that E3, Ascend, Black & Veatch, and Dr. Fripp should attend a Third Stakeholder Meeting to discuss, in greater depth, the modeling analysis.

Third Stakeholder Meeting: September 22, 2016

The day after Technical Conference #1, the Companies and Parties held their third meeting to review the conference proceedings and to continue the discussion from previous meetings. The following agenda was created and adhered to during the meeting.

Agenda for Joint Parties Discussion	
9:00–9:45	Clarity on Process ▪ Can methodology by modified. ▪ Can changes in the input assumptions be incorporated into the models. ▪ If not, explain how proposed changes would be incorporated into "scenarios"? ▪ Do your responses change if PUC added more time to the schedule. If so, how much time would be needed?
9:45–12:30	Methodology Discussion Explicit inclusion of fuel risk into optimization: ▪ Treatment of risk by Ascend: Explain methodology for calculating the risk premium and quantify your answer. ▪ Explain precisely how this is added to the NPV revenue requirements. ▪ Explain what the short term risk premium is based on?

	▪ Explain how these will be (or already have been): • Incorporated into E3 Resolve. • Built into PowerSimm. Discussion of alternative approaches to incorporating risk. Selection of 5 year plans in the context of long term direction. Integration and iteration between models: ▪ Funnel approach vs. integration/iteration approach. ▪ Integration of simplified risk, PV/storage/EV adoption, DR into the power optimization model. Identification of Ancillary Services Requirements: ▪ Analysis in model. ▪ Calculation and validation of reserve requirements for wind and solar forecast errors. ▪ How shortfalls are used to revise capacity models. ▪ How requirements are translated into near term actions. Scenarios.
12:30–1:30	Lunch Break.
1:30–3:00	Critical Inputs Assumptions: ▪ LNG ▪ Solar PV ▪ Storage ▪ Offshore Wind ▪ DER ▪ EV
3:00–3:30	Summary and Next Steps.

In-person and conference call bridge attendees at this Third Stakeholder Meeting included representatives from Blue Planet, DBEDT, Consumer Advocate, Hawai‘i Gas, Life of the Land, Paniolo Power, Sierra Club, and Ulupono together with staff and Company consultants: HD Baker, Solari Communication, Ascend Analytics, Black & Veatch, and E3. Almost the entire agenda was covered during the meeting, the only exceptions being the last four items of the Critical Inputs Assumptions which were covered in the Fourth Stakeholder Meeting.

We verified that our modeling analysis—hourly and sub-hourly—considers all aspects raised by the Parties: DG-PV uptake, DER and DR uptake, energy storage, load profiles, PV production profiles, tariffs, export rates, future grid programs, PV cost curves, storage cost curves, tax credits, fuel options, addressable populations, customer rates, inflation rates, cost of capital, numerous risk factors, integration costs, DR program benefits, EV projections and adoption, PV plus storage, economics and customer uptake relationships, avoided costs, alternative technologies, sales forecasts—nothing that could bias the results is being omitted.

Most of the meeting's discussion focused on dissecting our input assumptions; the modeling process of RESOLVE, PowerSimm Planner, and PLEXOS; the DR analysis, and how our analyses results in a near-term action plan and a foundation for long-term planning.

Despite Party protestations to the contrary, we explained how we have been fully transparent in our planning and modeling analysis. We have considered and incorporated all usable input and comments received from the Parties, clarified our approach to modeling analyses described in our Work Plan, and have posted for consumption by the Parties all input assumptions and other information employed in our process to develop an update to the PSIP.

We concluded the meeting by discussing our rationale for IPP modeling and our input assumptions for LNG and solar PV, including how we had considered and incorporated input from Hawai'i Gas and SunPower.

Everyone agreed to schedule a final meeting to finish discussing the agenda.

Fourth Stakeholder Meeting: October 19, 2016

A fourth, and final, stakeholder meeting was convened to conclude our discussions on analysis methodologies, input assumptions, and other related topics. Colton Ching, Hawaiian Electric Vice President of Energy Delivery, sent the following email to schedule this meeting.

> Hi everyone,
>
> As a follow up to our September 22nd meeting, I would like to propose a meeting on October 19th, 8:30-10:30am. Per Kyle's proposal at the conclusion of the September 22nd meeting, the idea for this next meeting is for parties to come to the meeting with a "sheet" of data on the assumptions and inputs that were discussed at the meeting. Information provided in the meeting will then be used for sensitivity analysis planned for our December 1 PSIP Update.
>
> In advance of the 10/19 meeting we will send tables of what we have thus far for those input assumptions discussed at our last meeting: on-island grid-scale solar sensitivity analysis, on-island grid-scale wind sensitivity analysis, Paniolo Power's wind and pumped storage hydro sensitivity analysis, and Hawai'i Gas' LNG sensitivity analysis. These tables will denote specific data fields provided by parties. The tables will also note where we are using our own data for fields in which specific data has not been provided by parties. This would be consistent with what was discussed at PUC's 10/3 technical conference.
>
> The intent of providing these tables is to transparently provide the detailed inputs we have

received to date for the sensitivity analyses and where we are using our own data. We are hopeful that these tables will facilitate parties' efforts to provide additional data and input on assumptions that they would like to be included. I would like to encourage meeting participants to review these tables beforehand and come prepared to provide a "redline" of the tables with the additional or alternative data and inputs they would like to be included in our sensitivity analyses. If there are parties calling in and using WebEx, we would appreciate an email of the redline version before the meeting so that we can set it up and make the tables available for all participants.

Additionally, given the interest that the PUC staff has shown in the sensitivity analyses we will be performing as part of the PSIP Update and the data and inputs to them, in addition to the parties, we will be inviting the PUC to attend and observe this October 19th meeting as well.

Thanks, and stay tuned for a follow up email providing the meeting room, call in bridge, and aforementioned tables.

Colton

Todd Kanja, Hawaiian Electric PSIP Project Lead, included the following text in the meeting invitation sent to the Parties and key Company staff and consultants.

This is a follow-up to the September 22nd Stakeholder Meeting. The intent of this meeting is to validate input assumptions for sensitivity analyses that was discussed at the September 21st Technical Conference and September 22nd Stakeholder Meeting. In particular, we'd like to reach agreement on the input assumptions for O'ahu on-island PV, O'ahu on-island wind, Paniolo Power's wind and pump storage hydro, and Hawai'i Gas LNG proposal. Depending on E3's ability to provide documentation on their approach to determining a hedge value of renewables and availability, we may include that as an agenda item as well. We are planning on a 2 hour meeting and will try to keep the discussion focused and concise. Our approach will be to prepare tables of the input assumptions from the parties and assumptions that we intend on making where data was not provided. We intend on distributing these tables by the end of the week so that the Parties have a couple of days to review and decide if our assumptions are appropriate or provide us with different assumptions. Our goal is to get agreement on the input assumptions so that E3 can run sensitivity analyses for each set of input assumptions.

Attached is an email that Colton sent to the Parties earlier today notifying them of this follow-up session.

I will send an update with the Webex information once it's available.

Thanks,
Todd

In-person and conference call bridge attendees at this final stakeholder meeting included representatives from the Commission, Blue Planet, DBEDT, Division of Consumer Advocacy, Hawai'i Gas, Life of the Land, Paniolo Power, REACH, Sierra Club, SunPower, and Ulupono; a representative from Siemens; all together with staff and Company consultants: HD Baker, Solari Communication, Ascend Analytics, Black & Veatch, and E3.

Mr. Ching opened the meeting by restating the purpose of the meeting: validating the input assumptions specified in the (above) meeting notice, specifically the O'ahu's on-island grid-scale wind and PV, Paniolo Power's wind and pumped storage hydro, and Hawai'i Gas's LNG proposal assumptions.

Participants first discussed Paniolo Power's input assumptions. Ulupono-representative Dr. Fripp then outlined the grid-scale wind, grid-scale PV, and rooftop solar assumptions used as input assumptions in the SWITCH model. Finally, we discussed the Hawai'i Gas assumptions in their LNG proposal.

In the week following this stakeholder meeting, we held a series of conference calls to further delve into the various suggested input assumptions and to discuss additional sensitivities to run.

In the end, we arrived at an agreement as to the assumptions that we would use as input for sensitivities to be run by E3 in RESOLVE in their modeling analysis. We ended by discussing the possibility of scheduling a meeting with E3 to review these input assumptions and the sensitivities to be run.

STAKEHOLDER CONFERENCE COMMENTS AND PRESENTATIONS

Paniolo Power Wind Resource and Energy Production Assessment

AWS Truepower®

PREPARED FOR
PARKER RANCH, INC.

ENERGY PRODUCTION SUMMARY

Assessment of the Wind Resource and Energy Production

DECEMBER 5, 2016

FOR THE PROPOSED PARKER RANCH WIND PROJECT

ISLAND OF HAWAII

CLASSIFICATION
CONFIDENTIAL

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DOCUMENT HISTORY

ISSUE	DATE	SUMMARY
A	5 December 2016	Initial Report

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1. INTRODUCTION

AWS Truepower, LLC, was retained by Parker Ranch, Inc. (Parker Ranch) to evaluate the long-term wind resource and energy production potential of the proposed Parker Ranch Wind Project, located in Hawaii, about 9 km to the south-southeast of Kapaau, and 19 km northwest of Waimea. This report presents the results of our analysis and summarizes the methods used to develop the wind resource and energy estimates.

2. WIND MEASUREMENTS

Wind monitoring at the Parker Ranch project began in August 2013 with the installation of two Triton sodar units, designated Sites 298 and 302. A sodar instrument is a mobile device that uses sound waves to remotely measure the wind speed and direction at heights that are well above typical mast heights. Table 1 presents basic information about the sodars including their geographic coordinates, elevations, periods of record and monitoring heights. The sodar units remain in operation. Parker Ranch provided the data to AWS Truepower via ftp. Each data file contained 10-minute average wind speed and direction records.

The sodar data were screened by AWS Truepower and found to be of good quality. The observed mean wind speeds at a height of 80 m, the proposed turbine hub height, are 8.08 m/s at Site 298 and 9.20 m/s at Site 302. The annualized mean wind speeds, which take into account repeated months in the data record and weight each calendar month by its number of days, are 8.05 m/s at Site 298 and 9.15 m/s at Site 302.

3. ESTIMATION OF LONG-TERM MEAN WIND SPEED

We obtained historical wind speed data from several regional potential reference stations operated by the National Weather Service (NWS), as well as a MERRA-2 dataset[1], and assessed them for suitability as long-term references.

Linear regression equations were established using concurrent daily mean wind speeds at Site 298 and each potential reference source. The strength of the correlation between the sodar measured wind speeds and the reference source observations varied widely among the different references. The same was true for the long-term wind speed estimates. We also consulted another long-term regional sodar dataset and, based on the evidence, ultimately concluded that the wind speeds during the sodar period of record were likely slightly below normal. Given the uncertainty with regard to the adjustment of the onsite data record to the climatological conditions, we elected to use the observed annualized 80 m mean wind speed of 8.05 m/s at Site 298 as our best estimate of the long-term mean wind speed.

The long-term wind speed at Site 302 was estimated using Site 298 as the reference. The regression was performed using concurrent daily wind speeds. Substitution of the estimated long-term speed at Site 298 into the regression equation yields a long-term mean wind speed of 9.12 m/s at Site 302. A summary of the estimated long-term wind speeds is presented in Table 2.

1 MERRA-2, which was developed by the National Aeronautics and Space Administration (NASA), utilizes a variety of observing systems which have been assimilated into a global three-dimensional grid by numerical atmospheric models at a horizontal resolution of 1/2° latitude and 2/3° longitude.

The sodar long-term 80 m wind speeds were compared to the existing AWS Truepower wind map of the region and were found to be somewhat higher than suggested by the map. We elected to adjust the wind map speeds upward by 3% to bring them more in line with the sodar observations. It should be noted that the wind speed discrepancy was larger than 3%, but since the map suggests much stronger speeds to the west and southwest of Site 302, we decided to employ a more conservative upward adjustment.

4. ESTIMATION OF LONG-TERM ENERGY PRODUCTION

The energy production of the proposed Parker Ranch Wind Project was estimated for two turbine layouts, one consisting of 20 turbines and the other containing 40 turbines, designed by AWS Truepower. The turbine layouts are presented in Figure 1 and Figure 2. The turbine model considered in this assessment is the Vestas V116-2.0 MW turbine with a 116 m rotor diameter and a hub height of 80 m. The 80 m wind speed data collected at Site 302 served as the input data to the energy estimates. Specifically, a wind speed frequency distribution was created from the 3-year dataset and scaled to match the array-average wind speeds of 9.61 m/s (20-turbine layout) and 9.43 m/s (40-turbine layout), respectively. The number of observations in each wind speed bin was then multiplied by the power output for the Vestas turbine at each speed bin at an estimated site air density of 1.109 kg/m^3 and then summed over all speed bins to produce a gross energy estimate. The gross energy production for each project scenario was then reduced by the estimated project losses. AWS Truepower assumed preliminary project losses of 18.3% for the 20-turbine layout and 20.1% for the 40-turbine layout. These loss estimates will be further refined upon a more detailed analysis. Table 3 provides the estimated gross and net energy estimates for the two layouts. The preliminary estimated net energy production for the 20-turbine layout is 205.5 GWh (58.6% net capacity factor), while the corresponding values for the 40-turbine layout are 497.5 GWh (56.7% net capacity factor).

WindLogics independently estimated the energy production potential of the Parker Ranch project, but assumed project losses of only 13.8%. Applying this loss value to the AWS Truepower estimated gross energy production would result in net capacity factors of 61.8% and 61.2% for the 20-turbine and 40-turbine layouts, respectively.

5. SUMMARY

The long-term wind resource at the proposed Parker Ranch Wind Project was estimated using data from two sodar sites. The energy production was simulated using an existing wind resource map of the project area that was adjusted to the sodar observations, a wind speed frequency distribution based on three years of data collected at Site 302, and the Vestas V116-2.0 MW turbine model at an 80 m hub height. Preliminary project losses were estimated by AWS Truepower to adjust the gross energy production to net production values. The preliminary net energy estimate for the 20-turbine layout is 205.5 GWH and 58.6% net capacity factor. The corresponding values for the 40-turbine layout are 397.7 GWH and 56.7%.

[redacted]

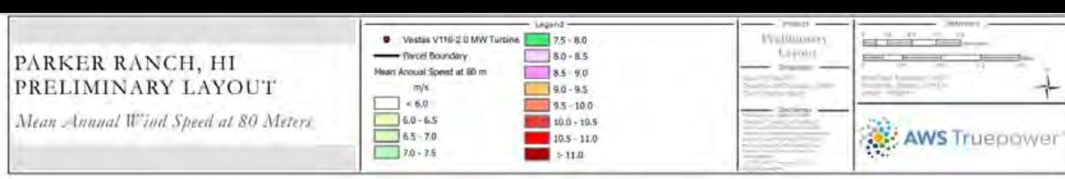


Figure 1. Proposed Parker Ranch 20-Turbine Layout

[redacted]

Figure 2. Proposed Parker Ranch 40-Turbine Layout

Table 1. Sodar Summary

Sodar	Site UTM Coordinates (WGS84, Zone 5)		Elevation (m)	Period of Record	Wind Speed and Direction Monitoring Heights (m)
	Easting	Northing			
298	[redacted]		799	8/30/2013 – 11/21/2016	200, 180, 160, 140, 120, 100, 80, 60, 40
302			642	8/30/2013 – 11/21/2016	

Table 2. Sodar Long-Term Wind Speed Projection Summary

Sodar	Monitoring Height (m)	Reference	Regression Equation	r^2	Long-Term 80 m Wind Speed (m/s)
298	80	-	-	-	8.05
302	80	Sodar 298	y = 1.013x + 0.963	0.97	9.12

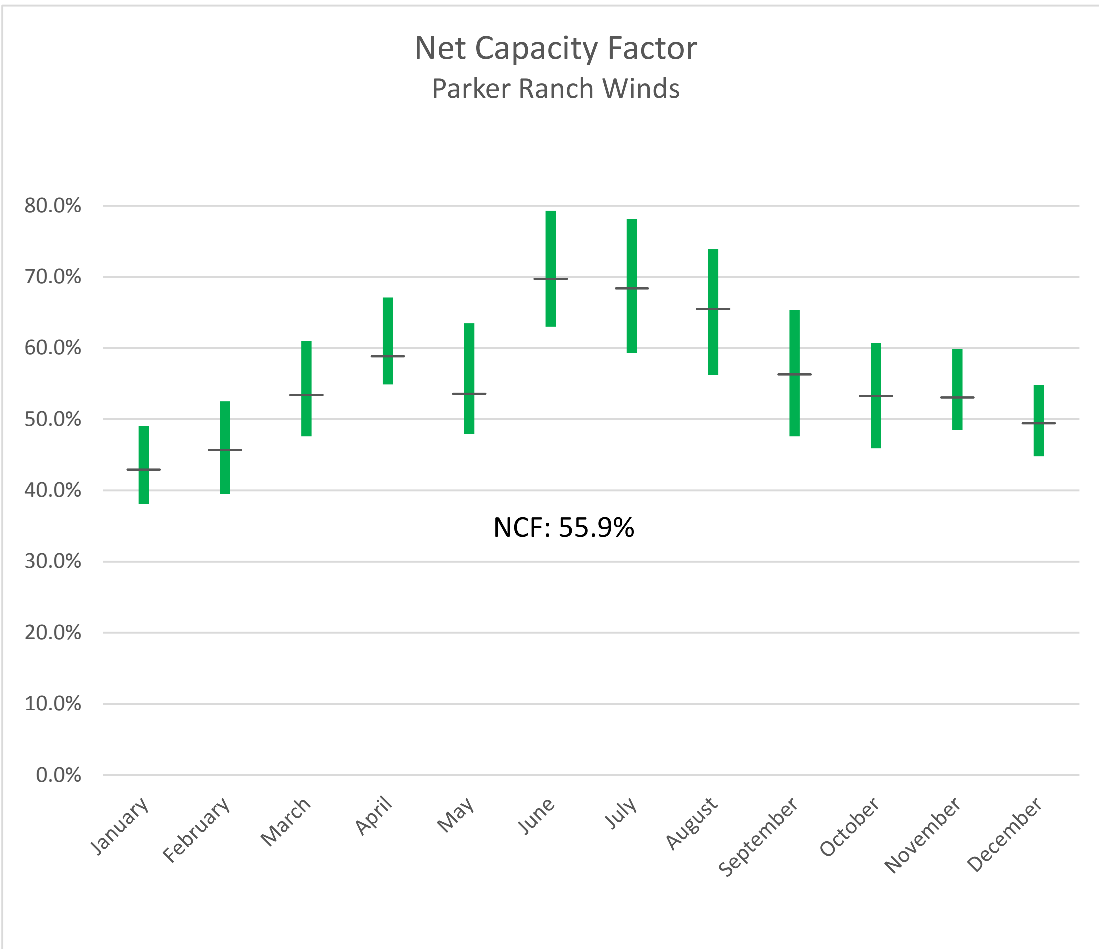
Table 3. Parker Ranch Preliminary Energy Production Estimates

Project Scenario	Gross Energy Output (GWh)	Net Energy Output (GWh)	Net Capacity Factor (%)
20-Turbine Layout	251.4	205.5	58.6
40-Turbine Layout	497.5	397.7	56.7

Parker Ranch Summary Wind Information, November 9, 2016

Actual wind data: September 1, 2013 to June 30, 2015 (1 year, 9 months)

Gross Capacity Factor (%)		**65.1%**
	Wake Effect	9.0%
	Availability	2.9%
	Electrical	2.5%
	Weather	0.0%
Total Project Losses (%)		**13.8%**
Net Capacity Factor (%)		**55.9%**



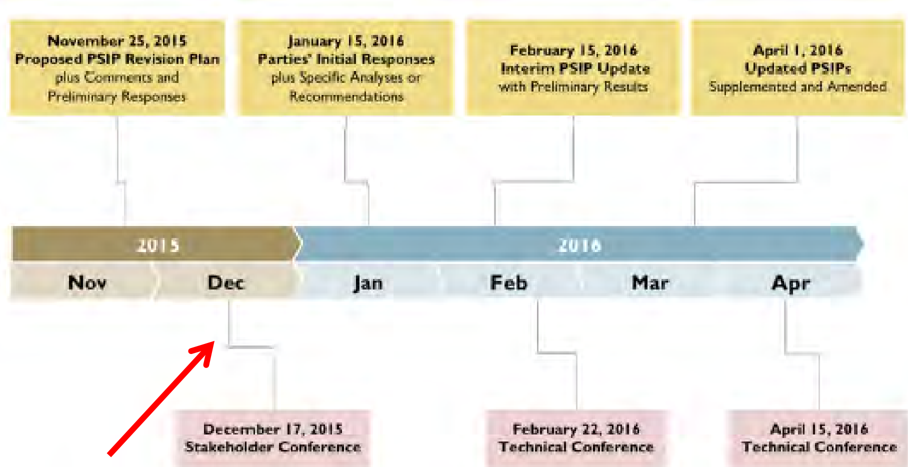
Next steps: AWS TruePower will review all actual wind data (spanning three years from 9/1/2013 to present) and use fewer and smaller turbines placed at the most optimal highest producing wind locations. We expect net capacity factor to exceed 55.9%.

Hawaiian Electric Presentation: First Stakeholder Conference

Hawaiian Electric
Power Supply Improvement Plan (PSIP)
Stakeholder Conference

December 17, 2015

Proposed PSIP Update Schedule



PSIP Stakeholder Conference 2

PSIP Stakeholder Conference Agenda

- Participant Presentations (30 min total)
  - DBEDT
  - REACH
  - Blue Planet
- Stakeholder Input and Discussion (2 hours)
  - 8 Observations and Concerns
  - Additional Pertinent Circumstances
- Concluding Remarks

PSIP Stakeholder Conference 3

Ground Rules

- Listen and be open to all ideas
- All dialogue is in confidence and off record. Please NO recording of this session.
- Always engage assuming no malicious intent, process is intended to be collaborative among the parties
- Try to provide supporting facts / data whenever possible when making comments
- Document issues requiring a deeper dive on the flip chart to there is adequate time to get through all critical topics
- Please silence cell phones to avoid disrupting others
- All dialogue should be directed through facilitator
- Leave preconceptions outside of conference
- Please avoid side bar conversations so the stakeholders can remain engaged
- Honor time limits so everyone has an opportunity to voice their thoughts

PSIP Stakeholder Conference 4

DBEDT

PSIP Stakeholder Conference 5

REACH

PSIP Stakeholder Conference 6

BLUE PLANET

PSIP Stakeholder Conference 7

Questions to Consider

- What Do You Want Analyzed?
- What Inputs Should be Considered?
- How Should the Information be Presented in the PSIP?

PSIP Stakeholder Conference 8

Stakeholder Input and Discussion: PUC's 8 Observations and Concerns

PSIP Stakeholder Conference 9

1. Customer Rate and Bill Impact:

PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable

PSIP Stakeholder Conference 10

2. Technical Cost and Resources Availability:

PSIPs Do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources

3. DER Integration:

PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources

4. Fossil-Fuel Plant Dispatch and Retirements:

Proposed Plans for Fossil-Fueled Power Plants are not Sufficiently Justified

5. System Security Requirements:

System Security Requirements Appear Costly and Are Not Sufficiently Justified

6. Ancillary Services:

Proposed Plan for Provision of Ancillary Services Lack Transparency and May Not be Most Cost-Effective Option

PSIP Stakeholder Conference 15

7. Inter-Island Transmission:

PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail

PSIP Stakeholder Conference 16

8. Implementation Risks & Contingencies:

Customer and Implementation Risks Are Not Adequately Addressed

PSIP Stakeholder Conference 17

Stakeholder Input and Discussion: Additional Pertinent Circumstances

PSIP Stakeholder Conference 18

Additional Pertinent Circumstances

- Increased RPS requirements established by Act 97 of the 2015 Hawai'i Legislature
- Substantial decrease in petroleum prices
- Limits the use of LNG as a cost-effective transitional bridge fuel that does not impede the utilization of renewable energy sources as established by Act 38 of the 2015 Hawai'i Legislature
- Changes in the estimated timing for implementation of major near-term projects in the 2014 Preferred Plans, including LNG utilization and BESS projects
- Potential significant changes in Federal energy policies that may affect Hawai'i's utilities, including the July 29, 2015 U.S. Supreme Court decision regarding Mercury and Air Toxics Standards (MATS) regulations and promulgation of the Clean Power Plan Final Rule.
- An announcement by the Governor of the State of Hawai'i regarding administration policy regarding utilization of LNG fuels for electric utility power production

PSIP Stakeholder Conference 19

Stakeholder Input and Discussion: Resource Options

PSIP Stakeholder Conference 20

Resource Option(s) That Will Assist in Development of Portfolios

- Future Pricing
- Developable Levels
- Issues

PSIP Stakeholder Conference 21

DBEDT Presentation: First Stakeholder Conference

Planning to Achieve an Energy Future that Meets or Exceeds the State's Public Policy Goals

Chris Yunker

Energy System & Planning Program Manager

HECO Stakeholder Conference

12/17/2015

HAWAII STATE Energy Office

DBEDT Expectation: PSIP Should Present a Clear and Transparent "Optimized" Roadmap Towards a 100% Renewable Future Consistent with the State's Vision

Fundamental questions to be answered:

"Our vision for Hawaii's energy landscape is a Hawaii that is energy independent, environmental and culturally sound, and adds value to Hawaii's people and businesses."
- Govenor Ige, WIRE address

- What potential renewable resources can be added today, to achieve near term targets (30% renewables) while maintaining flexibility to achieve optimized portfolios at 100%?
- What is information is required to decide on potential optimal resource portfolios at 100% that provide the greatest value to all electricity customers?
- When does information need to be available so that decisions can be made to keep on track for the roadmap to 100% renewable energy?

HAWAII STATE Energy Office

The States Comments Today Address a Subset of Identified PUC Issues

The fundamental questions discussed here address the following PUC identified issues:

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable
2. PSIPs do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources
3. PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources

….

7. PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail

HSEO will comment more comprehensively on these and additional issues, expectations and recommendations within the proceeding

DBEDT HAWAII STATE Energy Office

Near Term Planning Considerations for 30% Renewables

The State expects the PSIP to address near term decision points in the planning process including:

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable

1. Near term targets are met
   - Planning should not result in delays in implementation
2. Long term portfolio options remain viable
   - Current additions should be made cost effectively while preserving future options
3. Plans are regularly refreshed to allow for continued refinement of renewable portfolio
   - The interim resource targets need to be regularly updated to achieve progressive interim renewable penetration targets
4. Interim resource targets are subject to an identified RFP formula by which to evaluate resource combinations
   - To ensure low cost resource procurement targets are guides subject to market pricing
   - Individual resource targets could be exceeded if they prove lower cost when combined with normalizing mitigation factors (e.g. solar with storage relative to dispatchable bio fuels)

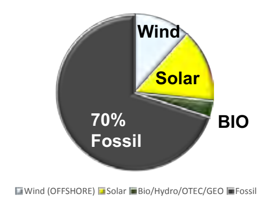
DBEDT HAWAII STATE Energy Office

What potential renewable resources can be added today, to achieve near term targets (30% renewables) while maintaining flexibility to achieve optimized portfolios at 100%?

ALL VALUES ARE ILLUSTRATIVE

Near Term Target

30% Renewable Mix



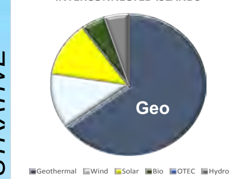
Total MW	Interim Target	Renew %
Wind	300	12%
Solar	650	15%
Bio	30	3%
Total		30%

2. PSIPs do not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources

Fits Within

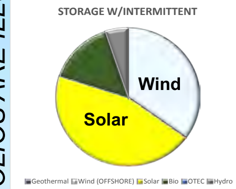
ALL PORTFOLIOS ARE ILLUSTRATIVE

INTERCONNECTED ISLANDS



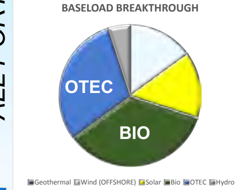
Total MW	Flat Load	30% Growth
Geothermal	800	1,100
Wind	300	400
Solar	700	950
Bio	60	80
OTEC	0	0
Hydro	100	150

STORAGE W/INTERMITTENT



Total MW	Flat Load	30% Growth
Geothermal	0	0
Wind	700	900
Solar	1,900	2,500
Bio	150	200
OTEC	0	0
Hydro	80	110

BASELOAD BREAKTHROUGH



Total MW	Flat Load	30% Growth
Geothermal	0	0
Wind	350	500
Solar	650	850
Bio	300	450
OTEC	300	400
Hydro	80	110

Resource mix can include distributed and utility scale resources

DBEDT HAWAII STATE Energy Office

The State feels the following information would be required to decide on optimal 100% renewable resource portfolios

- How do grid costs vary by portfolio?
  - How does the location of renewables and location of integration measures impact total costs and benefits (Utility Scale, DG/DER)
- How do renewable integration costs vary by portfolio?
  - What is the cost impact of the renewable mix on ancillary service requirements?
- What is the renewable potential by island and resource?
  - What is the technical potential?
  - What are the cultural impacts?
- What is the potential benefit of customer energy management
  - If loads can be modified by customers (usage or technology) what impact would it have on portfolio costs at 100%?
  - What is the costliest component of the load to serve?
  - Does the plan provide customers the opportunity to modify use to avoid creating costly loads prior to the utility being forced to make an investment to serve it?
- What is the economic impact of electricity to Hawaii?
  - What is the impact of price volatility?
  - What is the impact of long run average costs?

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable

2. PSIPs do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources

3. PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources

7. PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail

DBEDT HAWAII STATE Energy Office

When does information need to be available so that decisions can be made to keep on track for the roadmap to 100% renewable energy?

TIMELINE IS ILLUSTRATIVE

	2015 - 2020	2020 - 2025	2025 – 2030	2030 - 2035	2035 - 2040	2040 - 2045
Illustrative RPS Timeline	• Procure and build resources for 30% • IRP/PSIP for 40%	• RFP and begin development for 40% • IRP for 50%- 60% Resources	• Complete development of 40% • RFP for 50% - 60% • IRP for 70% Resources	• Development of 50% - 60% • RFP for 60% - 70% • IRP for 80% - 90% Resources	• Develop 60% - 70% Resources • RFP for 80% - 90% Resources • IRP for 100%	• RFP and development of 100% RPS
Illustrative Transmission Decision Timeline	Gather necessary info. including resource potential by island	Decision on inter-island cable arguably can occur no later than 2025 if not earlier to keep on track with targets beyond 40%		Transmission line available (if optimal path)		
Pricing reform	Timeline including rate design, AMI deployment, customer response and incorporation		Reasonably paced action today will allow for customer response to be incorporated into load forecasts in the mid 2020 timeframe			

- The State expects that the PSIP will address critical path items in a comprehensive timeline to show timely decisions can be made
- Given the compact timeline, the State expects any critical issue that is not directly incorporate into the current analysis will be identified in a timeline such that there is certainty in the timeframe in which it will be addressed

DBEDT HAWAII STATE Energy Office

REACH Presentation: First Stakeholder Conference

Renewable Energy Action Coalition of Hawaii

RESOURCE OPTIONS FOR GETTING TO 100% RENEWABLE ENERGY

Hawaiian Electric
Power Supply Improvement Plan (PSIP)
Stakeholder Conference

December 17, 2015

PSIP Stakeholder Conference 1

Participant Input to
Observations and Concerns Identified by the PUC

1. PSIP Cost Impacts and Risk Have Not Been Demonstrated to Be Reasonable
2. PSIPs do Not Appear to Aggressively Seek Lower-Cost, New Utility-Scale Renewable Resources
3. PSIPs do not Adequately Address Utilization and Integration of Distributed Energy Resources
4. Proposed Plans for Fossil-Fueled Power Plants are not Sufficiently Justified
5. System Security Requirements Appear Costly and Are Not Sufficiently Justified
6. Proposed Plan for Provision of Ancillary Services Lack Transparency and May Not be Most Cost-Effective Option
7. PSIP Analysis on Inter-Island Transmission Lacks Sufficient Detail
8. Customer and Implementation Risks Are Not Adequately Addressed

PSIP Stakeholder Conference 2

If one asks,
"What *mix* of options would get us to 40% renewable energy at *lowest aggregate cost*?

PSIP Stakeholder Conference 3

One gets a planning process that looks like this:

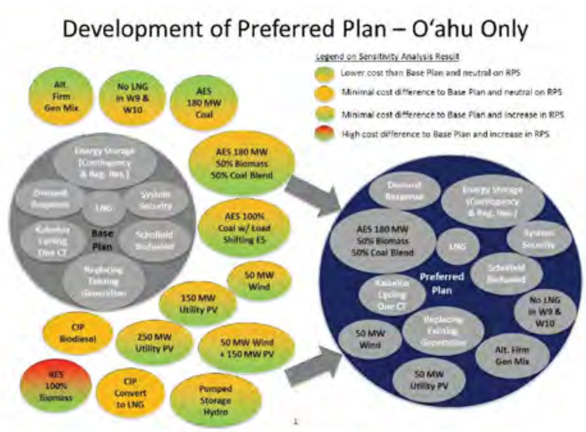


Figure L-2. Illustration of the Process for Developing the Hawaiian Electric Preferred Plan

PSIP Stakeholder Conference 4

And one gets a plan that looks like this:

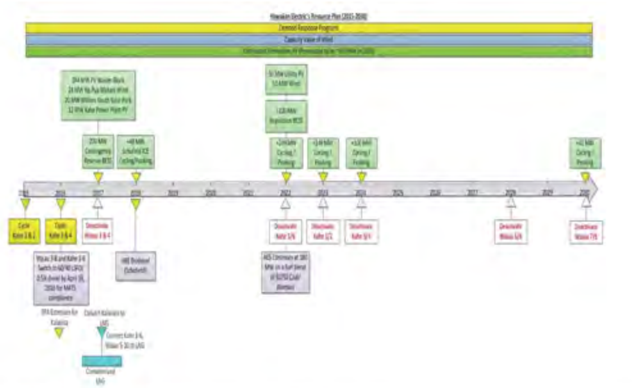


Figure ES-5. Hawaiian Electric Preferred Plan 2015-2030

PSIP Stakeholder Conference 5

If one asks
"What *options* in what *amounts*
in what *order* would get us
to 100% renewable energy
at *greatest benefit*
and *lowest cost*?"

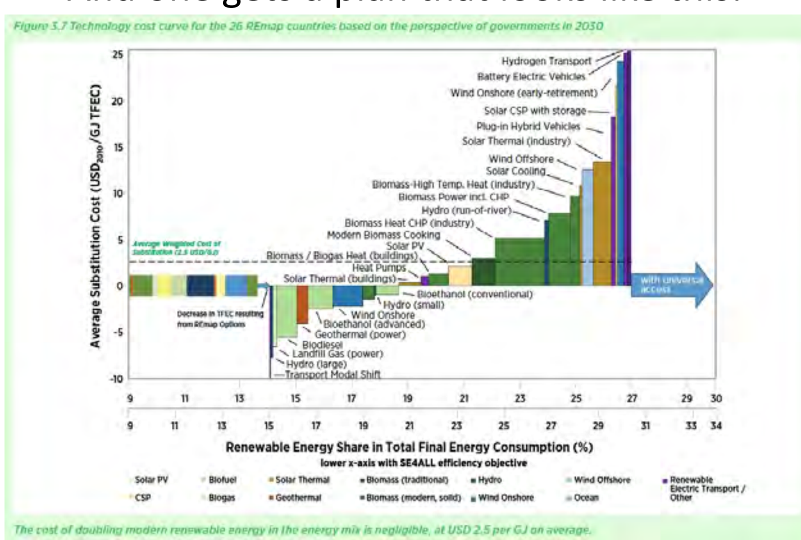
PSIP Stakeholder Conference 6

One gets a planning process that looks like this:

1) Identify plausible renewable energy options (renewable generation, T&D including mitigation, storage, demand management)
2) Evaluate options one-by-one for system performance impacts and cost & benefit
3) Compose plan prioritizing options evaluated to provide greatest benefit and lowest cost
4) Implement first step of plan
5) Use knowledge gained during first step of plan to re-evaluate options

PSIP Stakeholder Conference 7

And one gets a plan that looks like this:



PSIP Stakeholder Conference 8

Renewable Energy Action Coalition of Hawaii

RESOURCE OPTIONS FOR GETTING TO 100% RENEWABLE ENERGY

Hawaiian Electric
Power Supply Improvement Plan (PSIP)
Stakeholder Conference

December 17, 2015

Blue Planet Presentation: First Stakeholder Conference

Resource Combinations to Achieve 100% Renewable Power (Oahu focus)

Matthias Fripp

University of Hawaii, Manoa

- Asst. Prof. of Electrical Engineering
- U.H. Energy Research Organization (UHERO)
- Renewable Energy and Island Sustainability (REIS)

Blue Planet Foundation

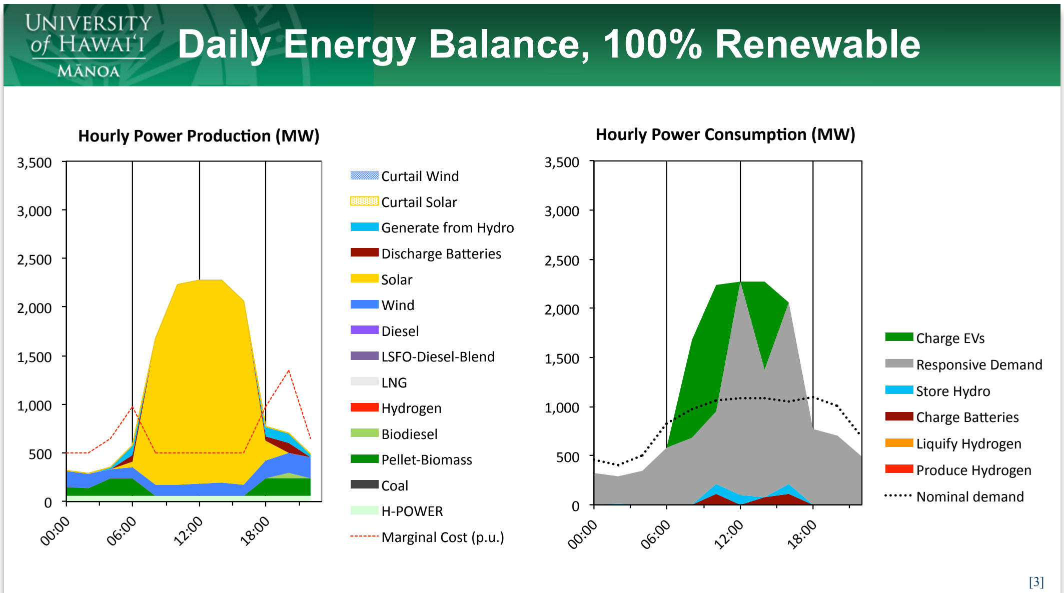
- Consultant

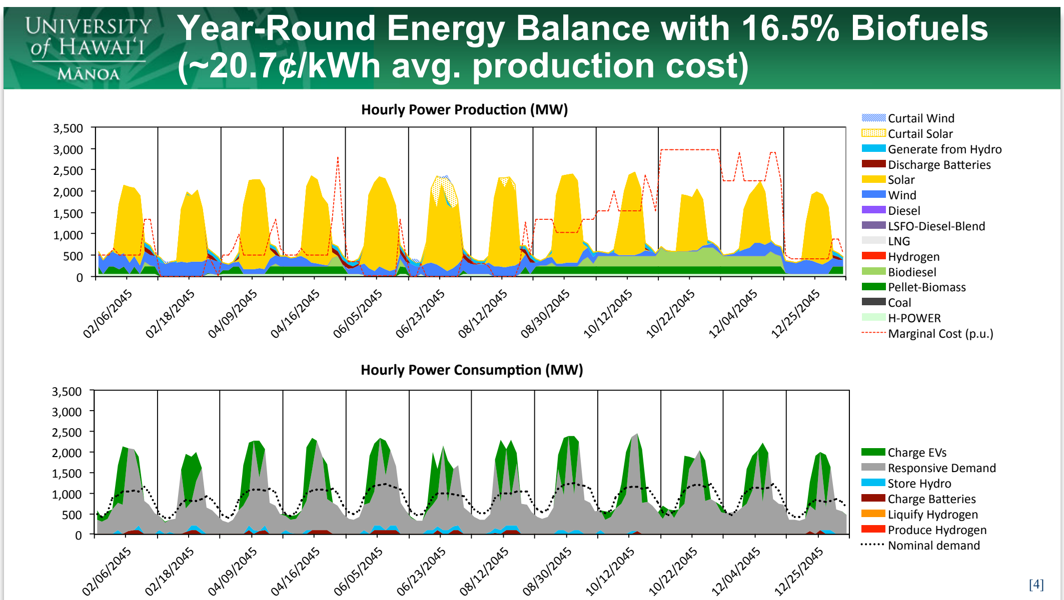
University of Hawai'i Manoa

Framework for Achieving 100% Renewable Power

- Meet overall energy requirements
  - Build wind projects where appropriate/suitable (up to ~300 MW on Oahu)
  - Build a lot of solar power (2,000–3,000 MW)
  - Use biofuels as needed/appropriate (0-16% of energy)
- Meet hourly energy requirements
  - Harness demand response via real-time electricity pricing (300 MW?)
    - Same loads can also provide "spinning" reserves
  - Build pumped hydroelectric storage if cost-effective (150 MW+)
  - Build as much battery capacity as needed (100–400 MW)
  - Fill in with biofuel or hydrogen when needed (400-600 MW)
- Meet seasonal energy requirements
  - Use biofuel or hydrogen on low-sun days
    - Produce hydrogen on high-sun / high-wind days

[2]


UNIVERSITY of HAWAI'I MĀNOA
Daily Energy Balance, 100% Renewable
Hourly Power Production (MW)
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
3,500
3,000
2,500
2,000
1,500
1,000
500
0
00:00
06:00
12:00
18:00
[3]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with 16.5% Biofuels (~20.7¢/kWh avg. production cost)
Hourly Power Production (MW)
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
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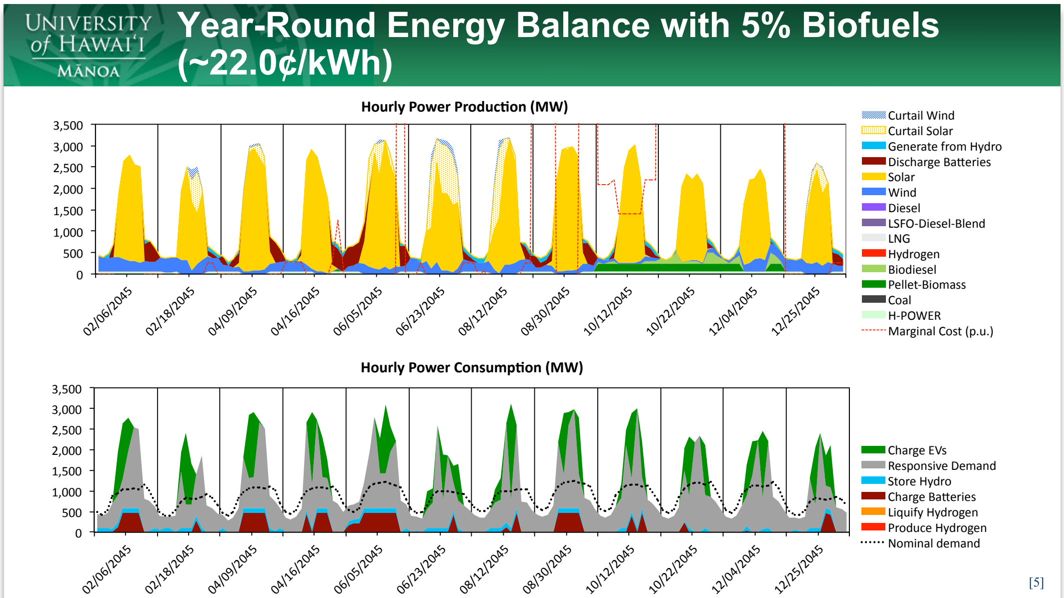
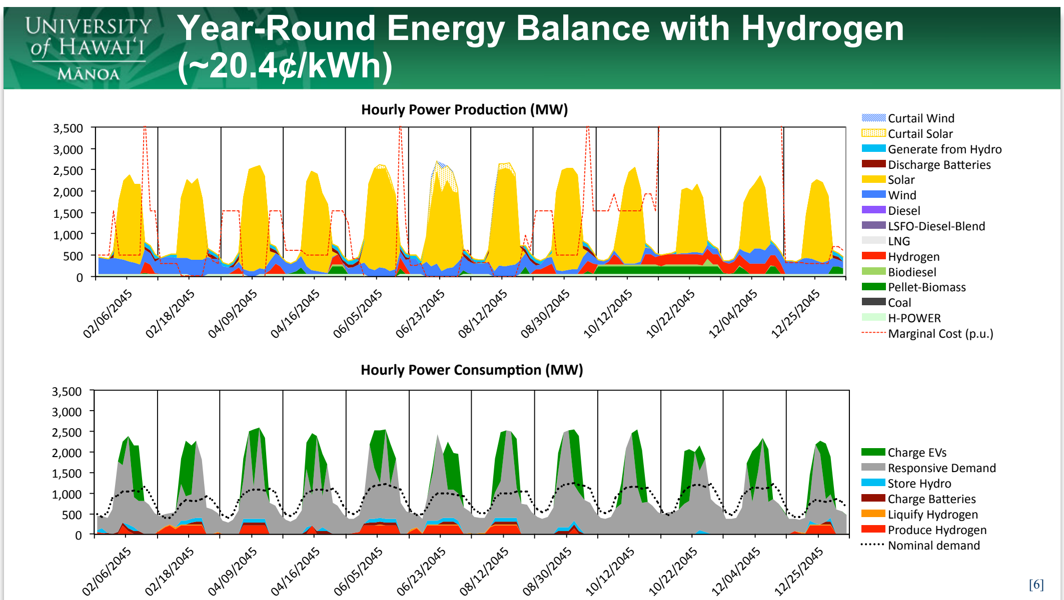
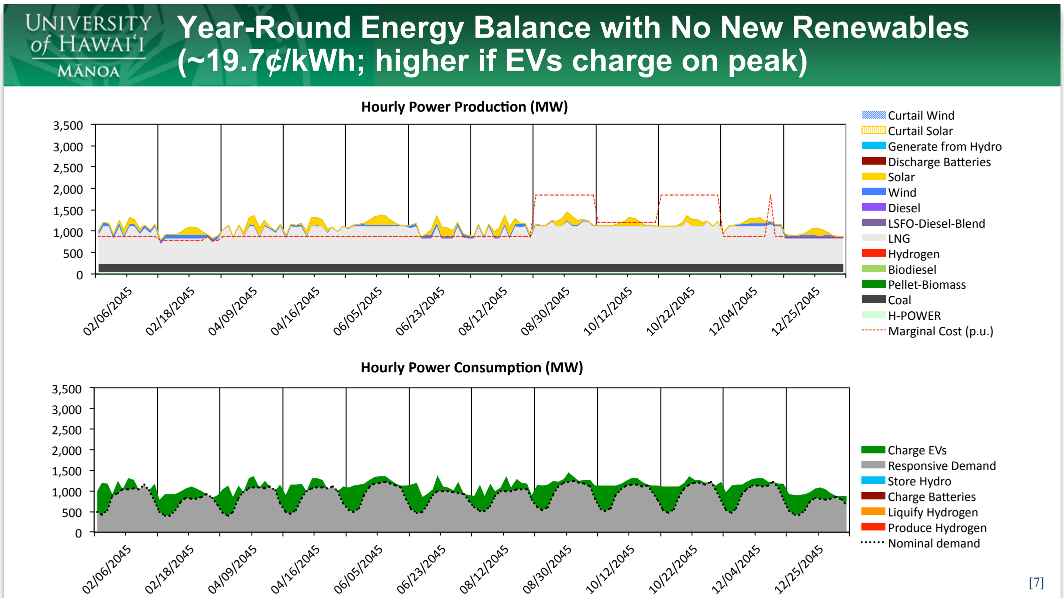
12/25/2045
[4]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with 5% Biofuels (~22.0¢/kWh)
Hourly Power Production (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
06/23/2045
08/12/2045
08/30/2045
10/12/2045
10/22/2045
12/04/2045
12/25/2045
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[5]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with Hydrogen (~20.4¢/kWh)
Hourly Power Production (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
06/23/2045
08/12/2045
08/30/2045
10/12/2045
10/22/2045
12/04/2045
12/25/2045
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
Wind
Diesel
LSFO-Diesel-Blend
LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[6]


UNIVERSITY of HAWAI'I MĀNOA
Year-Round Energy Balance with No New Renewables (~19.7¢/kWh; higher if EVs charge on peak)
Hourly Power Production (MW)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
02/06/2045
02/18/2045
04/09/2045
04/16/2045
06/05/2045
06/23/2045
08/12/2045
08/30/2045
10/12/2045
10/22/2045
12/04/2045
12/25/2045
Curtail Wind
Curtail Solar
Generate from Hydro
Discharge Batteries
Solar
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LNG
Hydrogen
Biodiesel
Pellet-Biomass
Coal
H-POWER
Marginal Cost (p.u.)
Hourly Power Consumption (MW)
Charge EVs
Responsive Demand
Store Hydro
Charge Batteries
Liquify Hydrogen
Produce Hydrogen
Nominal demand
[7]

Blue Planet Input: Second Stakeholder Conference

May 31, 2016

(*Via e-mail*)
Mr. Colton K. Ching
Hawaiian Electric
P.O. Box 2750
Honolulu, HI 96840
colton.ching@hawaiianelectric.com

Re: *PSIP Update - Comments on Further Work on PSIP*

Dear Colton:

This letter is in response to the request of the Hawaiian Electric Companies ("Hawaiian Electric") for informal comments by May 31, 2016, on the presentations made at the "Stakeholder Conference" convened on May 17, 2016.

Blue Planet Foundation, Earthjustice on behalf of Sierra Club, Paniolo Power Company, LLC, Distributed Energy Resources Council of Hawaii, Hawaii Renewable Energy Alliance, Hawaii Solar Energy Association, and County of Maui support the comments provided by Ulupono Initiative and other parties dated May 31, 2016, which recommends necessary fundamental improvements in Hawaiian Electric's PSIP analysis. However, we raise an equally important concern regarding the *process* of any collaboration between Hawaiian Electric and stakeholders, which *must* be a meaningful exercise in order to produce reliable results and inspire public confidence in Hawaiian Electric's proposed plans and projects.

In particular, the recent LNG applications[1] by Hawaiian Electric severely undercut the effectiveness and legitimacy of any such collaboration. By filing the LNG applications, Hawaiian Electric is prematurely seeking to implement the centerpiece of its proposed PSIP (and apparently also the centerpiece of its proposed merger with NextEra Energy). Such implementation is premature because the Commission has not yet issued comment, approval, or rejection for the latest iteration of Hawaiian Electric's proposed PSIP. At this stage, Hawaiian Electric's preferred plan is simply a proposal awaiting instruction from the Commission on next steps, and awaiting formal submission of analysis, testimony, statements of position, and other input from intervenors and participants. Unlike some other potential capital expenditures, the LNG applications are not broadly consistent with many potential outcomes of the PSIP process; the LNG applications are narrowly tailored to Hawaiian Electric's preferred PSIP outcome.

We hope that the PSIP process can be repaired without Commission intervention. To that end, further PSIP work should include the following steps:

[1] Applications filed in Docket Nos. 2016-0135, -0136, and -0137.

(i) Hawaiian Electric should immediately withdraw the LNG applications, not to be re-filed unless the Commission approves a PSIP plan that is wholly consistent with such applications.

(ii) Any further planning and analysis should divorce itself from issues of ownership, and thus from the forthcoming decision on the proposed merger with NextEra Energy. If Hawaiian Electric believes that subsequent large applications to implement the proposed PSIP need to incorporate merged/unmerged scenarios, then the LNG applications, and other contested core action steps, should be held until the merger is resolved.

(iii) Hawaiian Electric should welcome formal procedural mechanisms for PSIP intervenors and participants to provide further input (e.g. analysis, testimony, and statements of position) on the proposed PSIP for the Commission's record. The informal comments submitted here, narrowed to the select issues raised at the Stakeholder Conference, are not sufficient for stakeholders to fully contribute to the PSIP process and to the Commission's review of the proposed PSIP.

As Hawaiian Electric recently pointed out in a letter to Mr. Henry Curtis, further direction from the Commission regarding the PSIP process is anticipated:

> **Participants <u>will be allowed</u>—and are encouraged—to present analysis, testimony, statements of position, and reply statements of position as may be specifically allowed or required in further orders in this docket**. Participants shall not be permitted to file motions or responses concerning procedural and legal matters (such as those pertaining to scheduling, further changes in the scope of the proceedings, or other matters pertaining to the conduct of the proceeding), except as specifically allowed by the commission. **In addition, the scope and form of allowed discovery for Parties, Intervenors and Participants <u>will be governed</u> by further order of the commission**.

Order No. 33320 at 168 (emphasis added) (quoted in letter from Hawaiian Electric to Henry Curtis, Life of the Land, filed May 23, 2016 in Docket No. 2014-0183).

In the meanwhile, we are hopeful that Hawaiian Electric can take affirmative steps to improve both the PSIP analysis as outlined by Ulupono, and the PSIP process as outlined above, in order to facilitate effective energy planning and collaboration going forward.

The undersigned parties appreciate this opportunity to informally provide comments related to the presentations provided at the Stakeholder Conference. However, this is not intended to be—nor can it be—a comprehensive review, comment and response to Hawaiian Electric's updated proposed PSIP filed on April 1, 2016.

None of the informal comments submitted should be construed as such. The Commission has not yet established subsequent procedural steps for the parties and Hawaiian Electric to provide and address comprehensive responses to the updated proposed PSIP. Accordingly, the undersigned parties reserve the right to provide comments, responses, testimony, and statements of position etc. on the updated proposed PSIP to the Commission in the docketed proceeding when appropriate.

Respectfully,

/s/ Richard Wallsgrove
Policy Director
Blue Planet Foundation

/s/ Isaac Moriwake
Earthjustice
Attorneys for Sierra Club

/s/ Jose Dizon
General Manager
Paniolo Power Company, LLC

/s/ Leslie Cole-Brooks
Executive Director
Distributed Energy Resources Council of Hawaii

/s/ Warren Bollmeier
President
Hawaii Renewable Energy Alliance

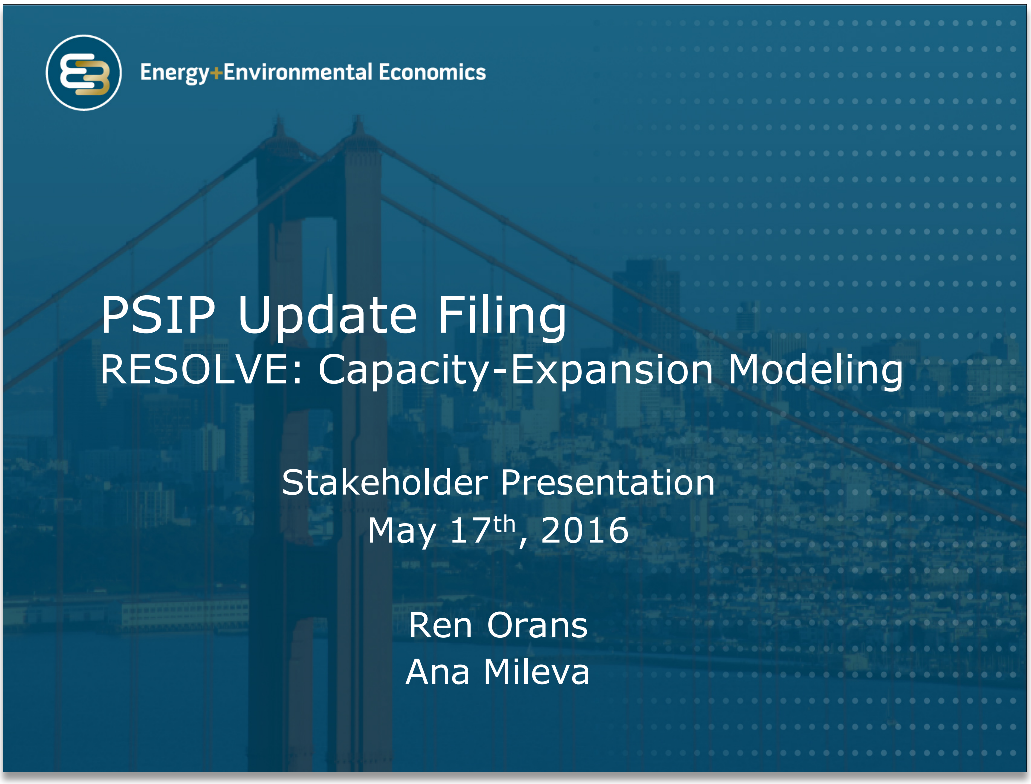
/s/ Rick Reed
Director
Hawaii Solar Energy Association

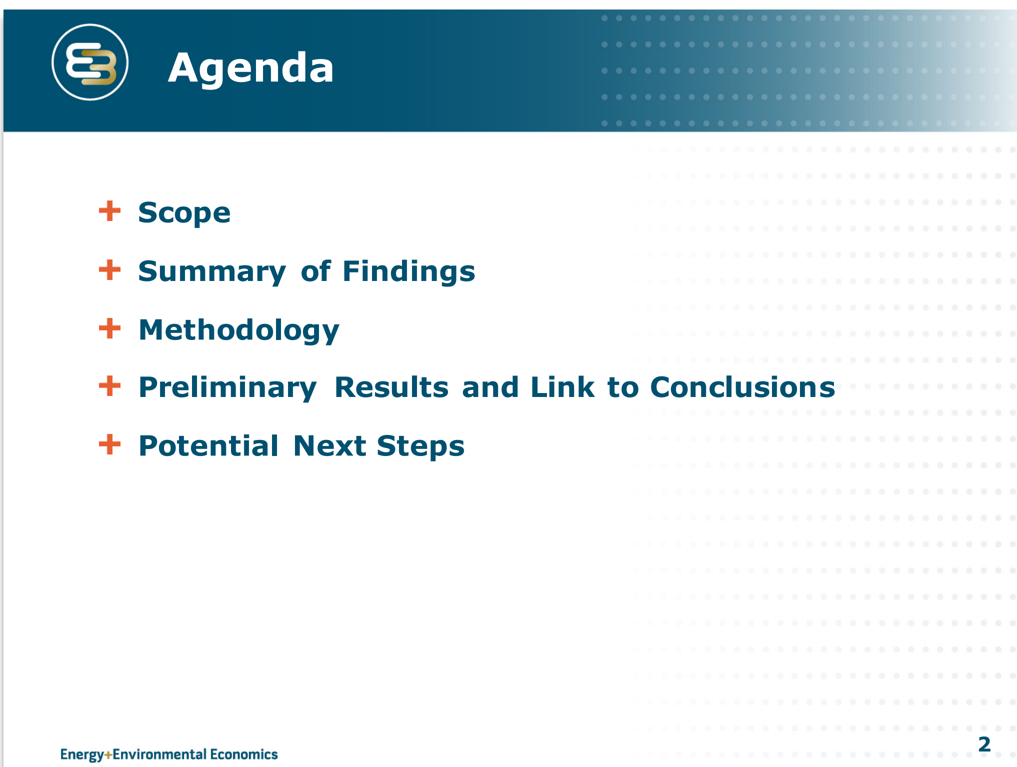
/s/ Frederick Redell, PE
Energy Commissioner
County of Maui Office of Economic Development

/s/ Kalvin Kobayashi
Energy Coordinator
County of Maui Department of Management

Cc:
Public Utilities Commission, Consumer Advocate, Participants and Intervenors in Docket No. 2014-0183 (via Stakeholder Conference e-mail distribution list)

E3 Presentation: Second Stakeholder Conference





Scope

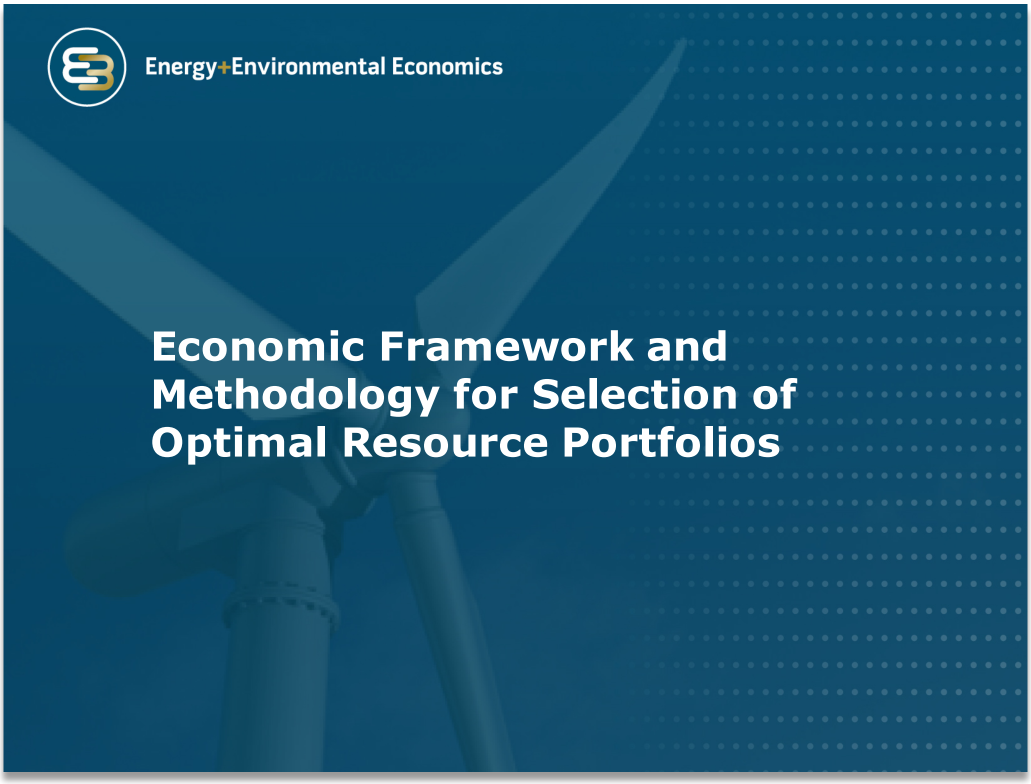
- **Address some of the previous filings' shortcomings identified by the Commission**
  - Leverage E3's extensive modeling experience in long-term planning from California and New York to inform HECO planning decisions
- **Identify short-term and long-term decision points for HECO on the path to 100% RPS on O'ahu**
- **Test robustness of HECO's proposed short-term decisions with regard to a plausible range of long-term scenarios**

Energy+Environmental Economics 3

Summary of Findings

- **The LNG investment decision is critically dependent on the spread in fuel prices**
  - Lower future oil prices would reduce the savings provided by LNG
  - Faster ramp-up in RPS would limit the ability to recover the cost of the LNG infrastructure
- **The capital cost of renewable resources and supporting infrastructure – including transmission and balancing solutions – becomes increasingly important relative to fuel costs over time as the RPS target increases**
  - Shifts focus from fuel cost savings to integration solutions and optimal capacity-expansion planning
  - Major decision points are on large capital investments independent of fuel price projections
- **Limited renewable potential on O'ahu requires deployment of off-island renewable resources and transmission infrastructure**

Energy+Environmental Economics 4



Methodology

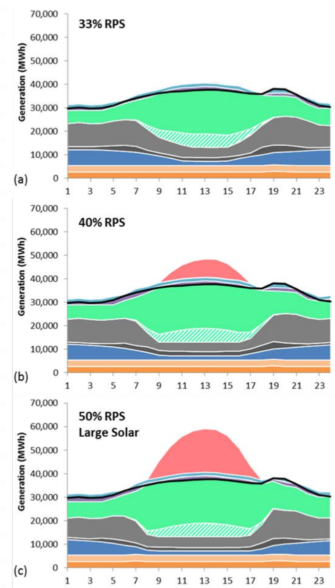
+ **Question: How to align the planning process with the Commission's vision for the future grid?**

+ **E3 RESOLVE is an optimal investment planning model**
  - Selects least-cost resource portfolio and integration solutions to meet RPS targets
  - Considers all resource options on level playing field
  - Evaluates long-term benefits of investments as renewable portfolio evolves over time
  - Allows investigation of new policy and regulatory reforms
+ **Suited to addressing many of the challenges in the Commission's Inclinations document**
+ **Complementary approach to detailed production simulation modeling**

Energy+Environmental Economics 6

The renewable integration challenge

+ **Primary drivers of renewable integration challenges at high penetrations:**
  - Renewable oversupply during low load periods
  - Inflexible conventional generation
    - Must-run resources
    - Self-scheduled resources/contract limitations
    - Technical constraints on ramping, minimum stable levels, minimum up and down times
    - High costs associated with cycling
  - Small balancing areas where diversity of renewables is limited, and generator fleets are constrained



Energy+Environmental Economics 7

Renewable integration solutions

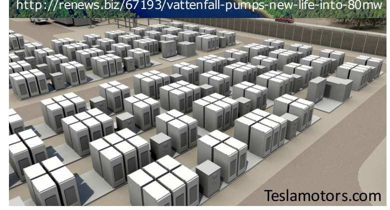
+ **Various solutions have been proposed, with different performance characteristics and costs**
  - Energy storage (batteries, compressed air, etc)
  - Flexible loads or advanced DR
  - Flexible resources (new flexible CCGTs, Aero CTs, Reciprocating Engines or retrofits to existing plants)
  - Tariff design, regulatory and market changes

http://www.theiet.org/membership/member-news/31a/ev-charging-course.cfm

http://allthingsd.com/files/2012/10/Nest-Cooling-2.jpg

Wartsila.com

http://renews.biz/67193/vattenfall-pumps-new-life-into-80mw

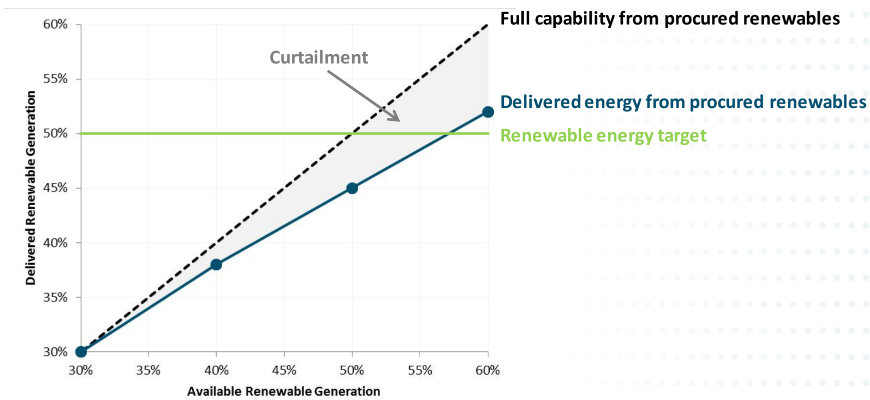


Teslamotors.com

8

Economics of renewable integration

+ **The consequence of failing to supply enough flexibility to integrate renewables is renewable curtailment, or reliability issues**



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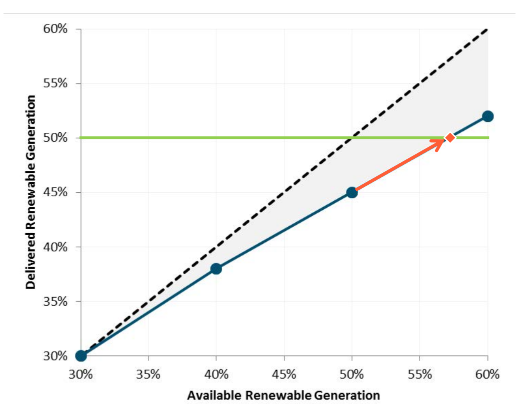
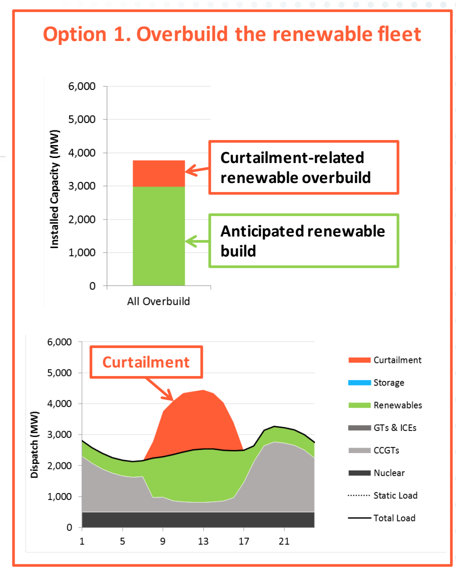
Option 1. Overbuild renewables

+ **Overbuilding the renewable fleet allows for policy goal to be met with some allowance for curtailment**





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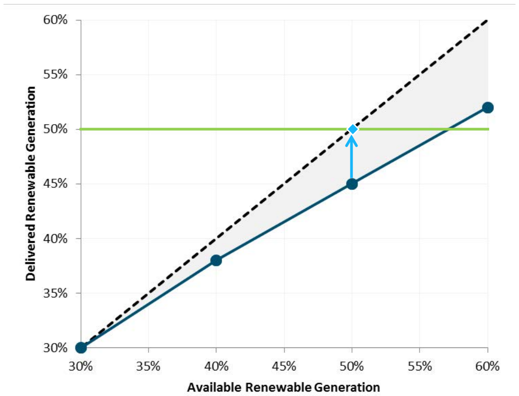
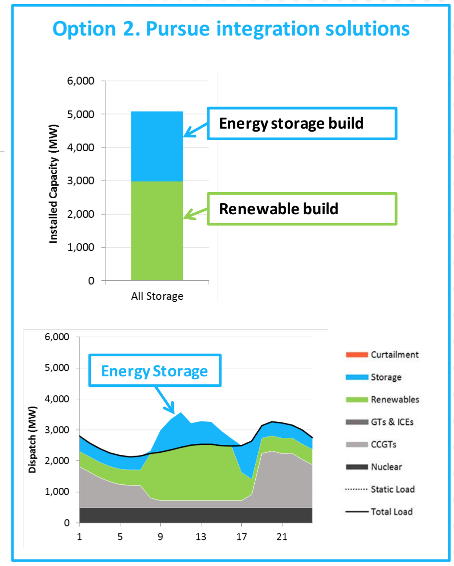
Option 2. Pursue integration solutions to avoid overbuild

+ **Integration solutions (eg. storage, balancing area consolidation) permit more effective delivery of existing renewable fleet**





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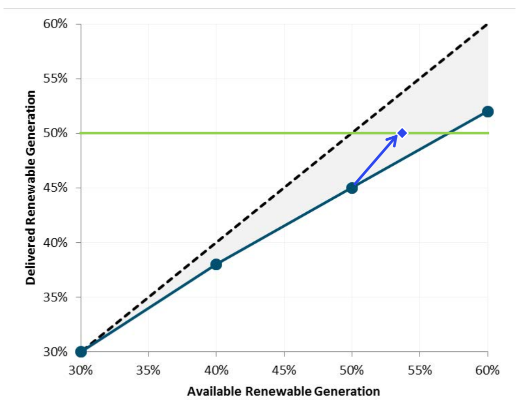
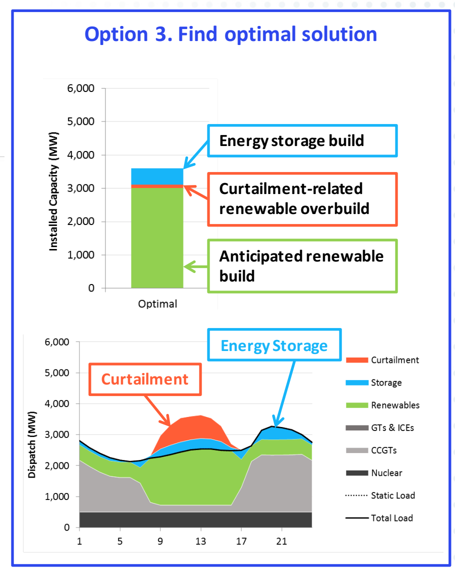
Option 3. Determine optimal mix of solutions and overbuild

+ **Optimal solution combines multiple strategies based on costs and benefits**





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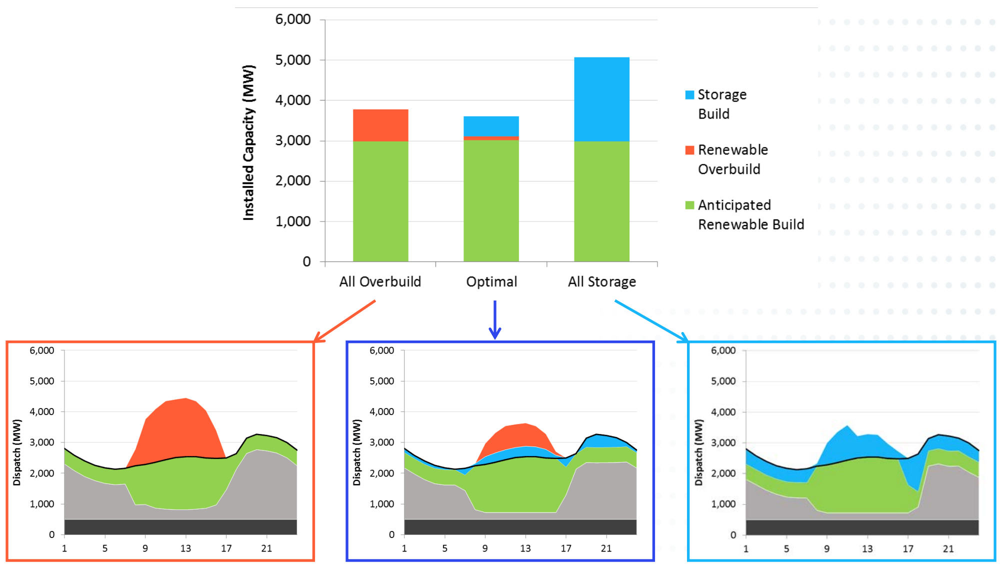
Optimal solution balances non-renewable solutions with overbuild



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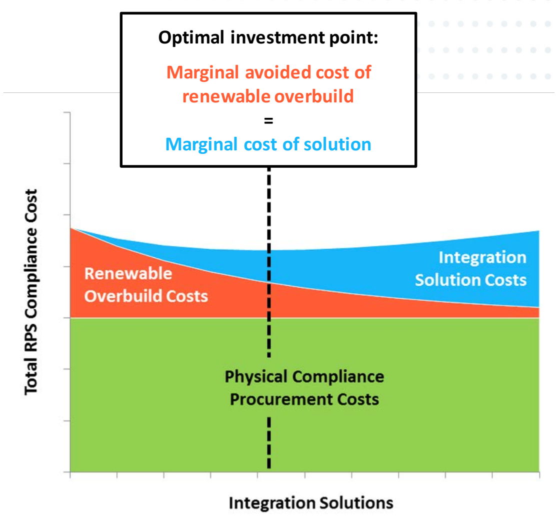
Identifying optimal investment in solutions

- **Single solution case:**
  - The cost of the solution can be weighed against the avoided cost of overbuilding renewables for RPS compliance
- **Multiple solution case:**
  - Multidimensional optimization
  - Complex interactive effects
  - **Requires models that treat both operations and investment costs**
    - SWITCH and RESOLVE are examples of such models



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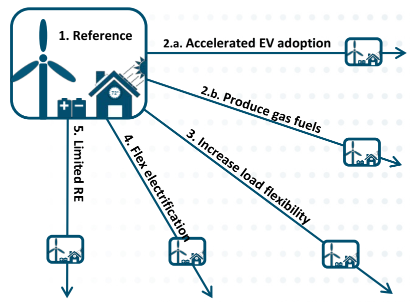
Optimal Expansion Planning

- Optimal expansion planning models can be used to investigate some of the questions the HPUC asked HECO to address in the PSIP update
- Parties can vet model assumptions and models can provide results for a range of curated scenarios
- Such models can be used to begin a constructive discussion about forming a well-balanced, robust portfolio of resources that meets Hawaii's needs



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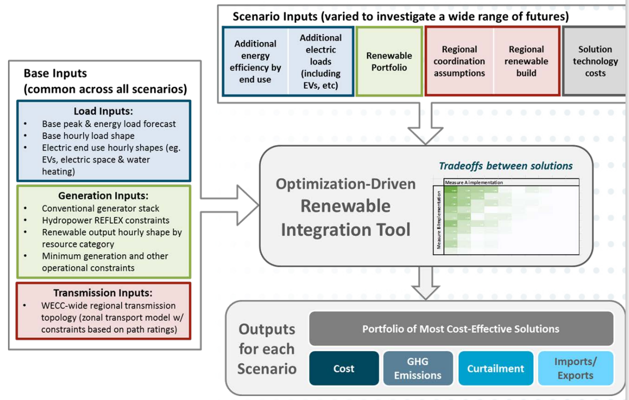
RESOLVE Modeling Framework

+ **Co-optimizes investment and operational decisions over multiple years**
  - Can solve for optimal investments in renewable resources, energy storage, conventional generators
  - Can test value of solutions with unknown or uncertain supply curves, like flexible loads & time-of-use rates



+ **Operational detail focuses on primary drivers of renewable integration challenges**
  - Hourly dispatch with reserve and operating constraints
  - Zonal treatment of interconnection to model flows with increased granularity in primary zone of study

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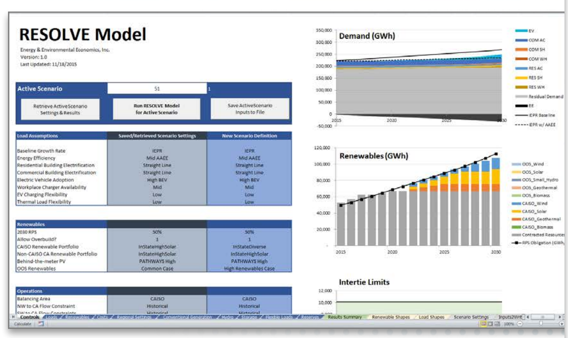
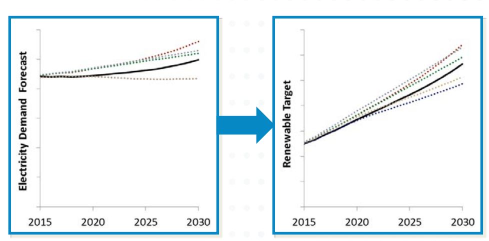
Scenario-based analysis produces more robust conclusions

+ **Scenarios determined by:**
  - Loads by subsector, including residential and commercial thermal loads, electric vehicle adoption, & energy efficiency
    - Dynamically-updated hourly load shapes
  - Renewable policies
    - RPS targets and behind-the-meter PV adoption
  - Renewable resource costs and potentials
  - Costs
    - Renewable, conventional, and storage technology costs, transmission costs
    - Fuel prices





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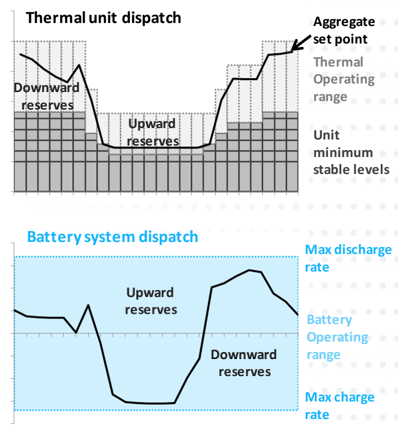
Detailed hourly model brings operational challenges into investment decisions

+ **For each year in the simulation, a subset of days are selected and weighted to reflect long-run distributions of:**
  - Daily load, wind, and solar
  - Monthly hydro availability (in CA)
+ **Operations modeled using linear dispatch formulation**
  - MIP possible for small systems or when runtime is not a constraint; linear approximations for large systems
  - Upward and downward operating reserve constraints

Simulates economic dispatch on each day subject to technical operating constraints



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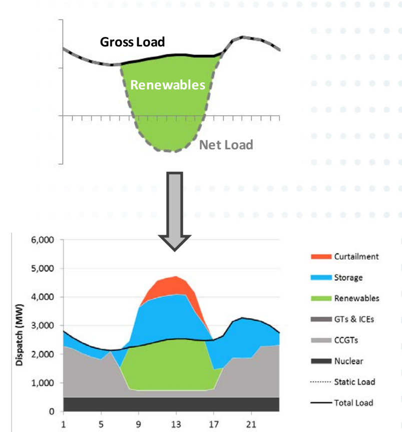
Detailed hourly model brings operational challenges into investment decisions

+ **For each year in the simulation, a subset of days are selected and weighted to reflect long-run distributions of:**
  - Daily load, wind, and solar
  - Monthly hydro availability (in CA)
+ **Operations modeled using linear dispatch formulation**
  - MIP possible for small systems or when runtime is not a constraint; linear approximations for large systems
  - Upward and downward operating reserve constraints

Captures operational impacts of renewable integration challenges



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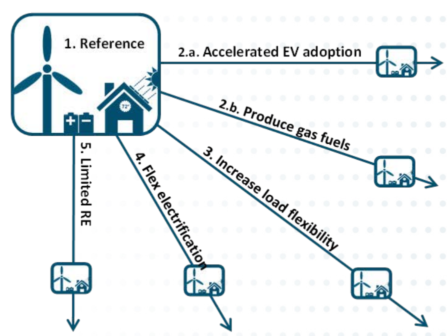
RESOLVE
Exploratory Results for O'ahu

Scenarios

- **E3 developed several high-level scenarios to represent different policy directions for Hawaii**
- **Cases include:**
  - Reference
  - Flexible Loads
  - Direct Electrification
  - Flexible Electrification
  - Produced Fuels
  - Limited Renewable Potential
- **Fuel price, technology cost, and technology availability sensitivities explored within each high-level scenario**



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Key Assumptions

+ **Loads**
  - HECO's 2014 load used as basis to begin forecast
  - 1.15% annual load growth assumed through 2045; peak load reaches 1,667 MW in 2045 from 1,170 MW in 2014
  - Transportation load added separately and varies depending on case

Annual Transportation Load (GWh)	2020	2025	2030	2035	2040	2045
Reference	73	239	494	705	847	933
Direct Electrification	110	385	816	1,238	1,521	1,631
Produced Fuels	258	898	1,897	2,960	3,717	4,011

+ **RPS targets: 40% in 2030, 70% in 2040, and 100% in 2045**
+ **O'ahu Resource Potential**
  - 779 MW of rooftop PV assumed built by 2045
  - 154 MW of onshore wind
  - 3,452 MW of utility PV
    - Updated O'ahu resource potential is considerably lower (600 MW), but E3 tested only as a sensitivity

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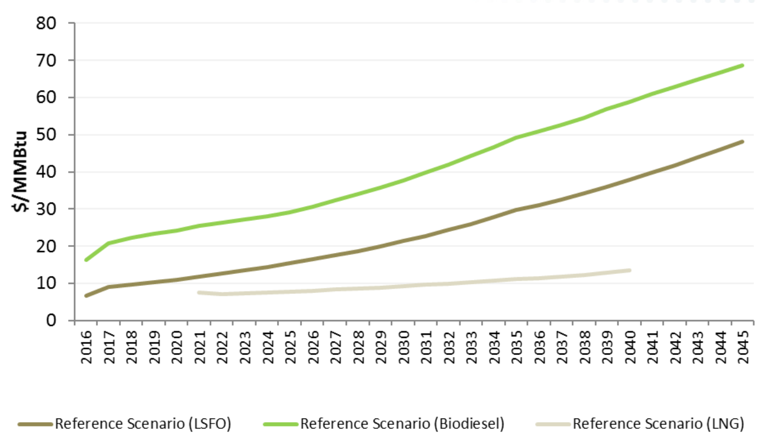
Key Assumptions

+ **Fuel prices**
  - Reference, Low, and High fuel price scenarios for LSFO, Biodiesel and LNG



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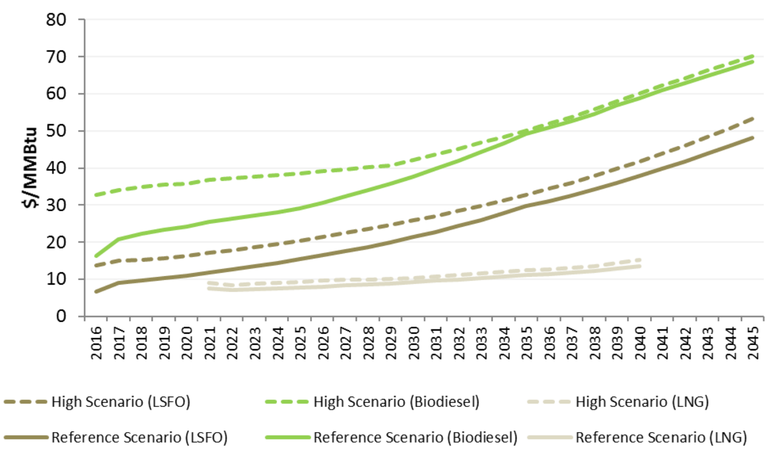

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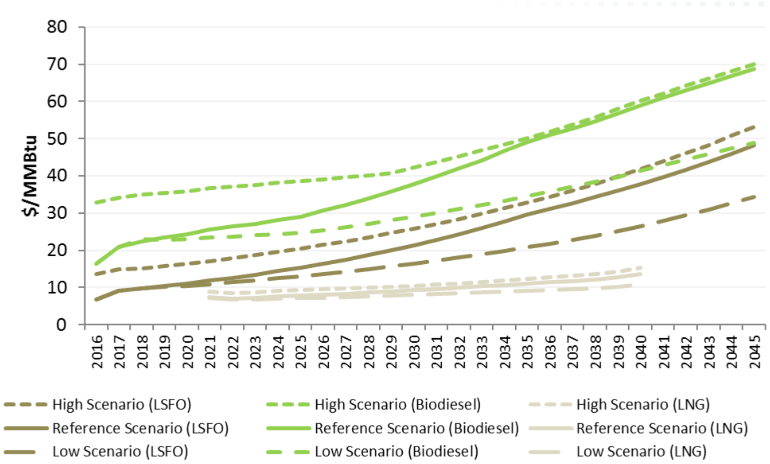

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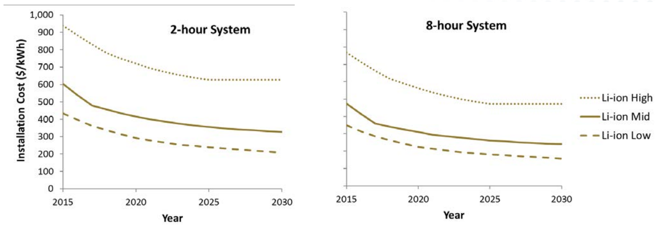
Key Assumptions

+ Generation Technology Costs

$/kW (AC) Year	Onshore Wind	Offshore Wind	Utility-Scale Solar PV
2016	2405	4971	2719
2020	2253	4115	2201
2025	2263	3356	1890
2030	2181	3112	1689
2035	2095	2940	1524
2040	2020	2818	1376
2045	1942	2703	1242

+ Storage Technology Costs



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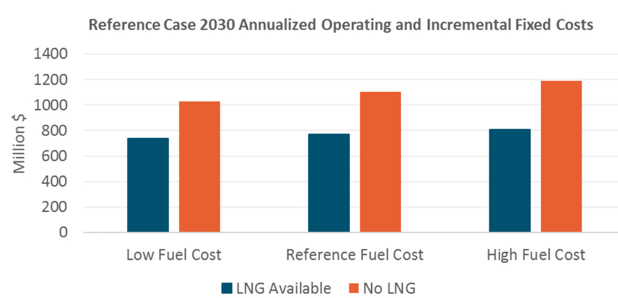
The LNG Decision

- **E3 used RESOLVE to find the annualized operating cost and incremental investment cost for a range of policy cases and the HECO fuel price forecasts**
  - Not including cost of LNG storage
- **Benefits depend on the spread between LNG and fuel oil prices**
  - Strongly tied to the fuel forecast assumptions
- **Depending on fuel price trajectory, $293-$383 million benefit per year in 2030 in the Reference Case**
- **Benefits decrease over time as system uses less fuel due to renewable additions**



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*Cost of LNG storage containers or contracting fixed costs and inter-island cable to access solar from outside O'ahu not included

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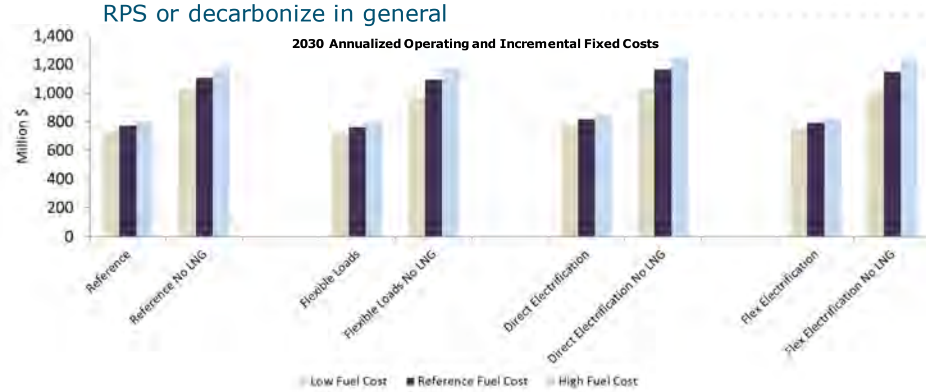
The LNG Decision

- **LNG looks like a short term "least regrets" decision**
  - If the required capital investments in storage, piping, and delivery terminal are less than the estimated benefits
  - If the updated fuel price forecasts developed by HECO are accurate
  - Decision not critically dependent on later decisions to meet 100% RPS or decarbonize in general



*Cost of LNG storage containers or contracting fixed costs and inter-island cable to access solar from outside O'ahu not included

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Meeting 100% RPS

- **O'ahu renewable resource potential is limited**
- **Off-island renewable options are needed to meet the 100% RPS target**
- **Options include:**
  - Offshore wind
  - Inter-island cable – high-solar case?
  - Biofuels
- **Preliminary work shows different integration solutions may be needed depending on option chosen**

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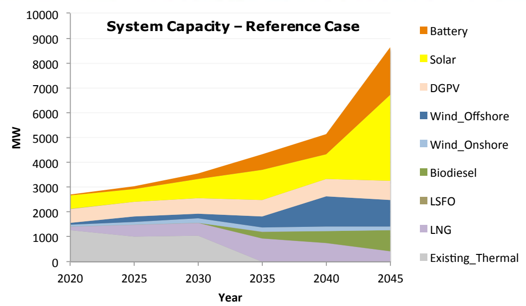
Meeting 100% RPS, Reference Case

- Meeting the 100% RPS is dominated by capital investments
- Resources with high fixed costs but low variable costs such as photovoltaics (3,452 MW), wind (154 MW onshore wind; 1060 MW offshore wind), and batteries (1938 MW) need to be procured in Reference Case



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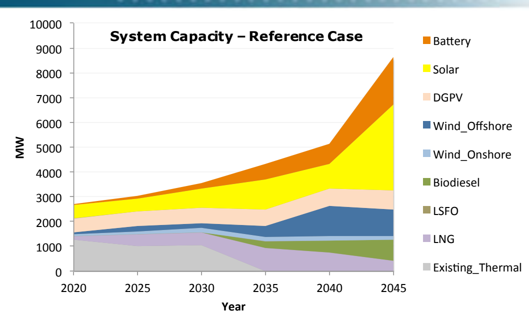
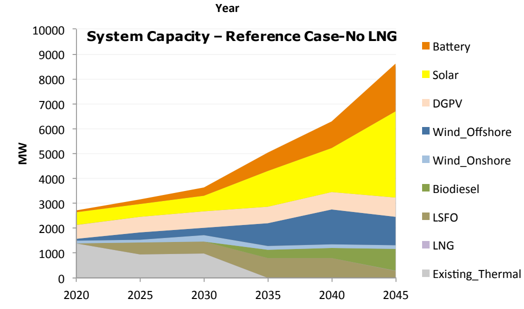
Meeting 100% RPS, Reference vs No LNG

- Meeting the 100% RPS is dominated by capital investments
- Resources with high fixed costs but low variable costs such as photovoltaics (3,452 MW), wind (154 MW onshore wind; 1060 MW offshore wind), and batteries (1938 MW) need to be procured in Reference Case
- This is the case with or without LNG, as at 100% RPS, biodiesel is the only available renewable fuel





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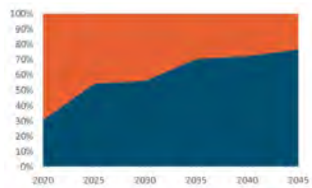
The Cost of Meeting 100% RPS

- **Fuel prices are important for determining if LNG conversion and new plant investment is cost-effective, but they become increasingly less important as O'ahu approaches 100% RPS**
- **Focus shifts to optimal expansion planning for renewables portfolio, transmission, and integration solutions**



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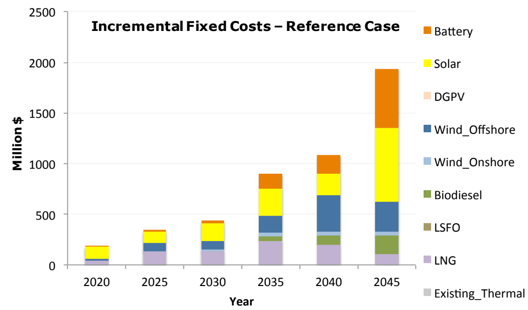

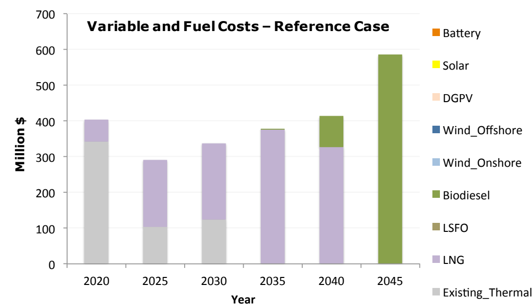

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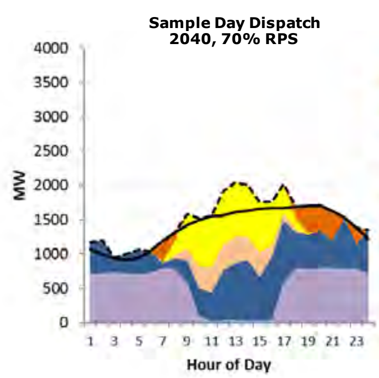
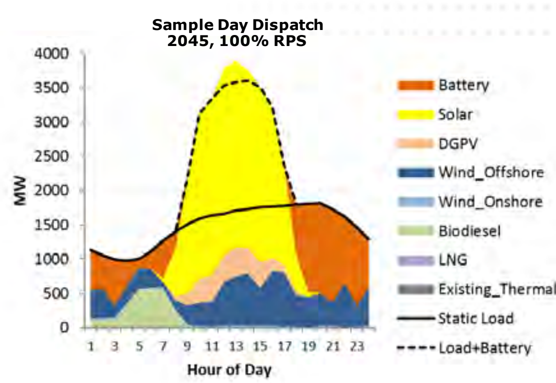
Renewable Integration Solutions are Needed

- **Batteries are used to store solar energy during the day and dispatch that energy to help meet load when the sun is not shining**
- **Stored solar energy complemented by offshore wind and biofuels**





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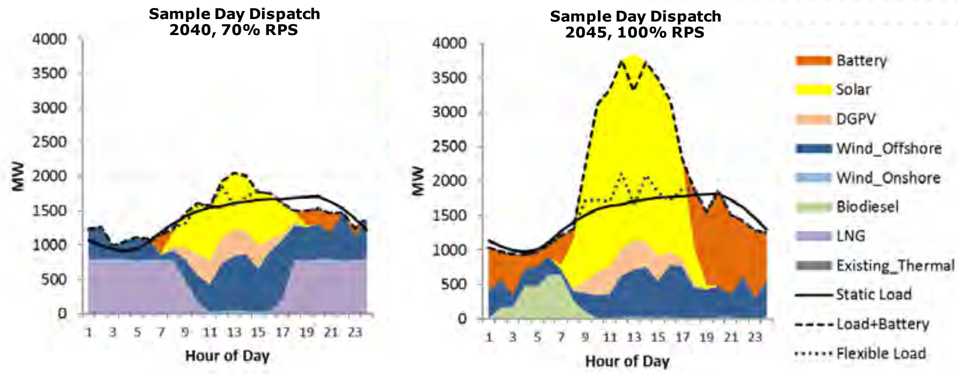
Renewable Integration Solutions: Flexible Loads

- **Flexibility from load and electric vehicles can reduce the cost of meeting the 100% RPS target and should be explored in more detail**
  - Battery procurement is lower in the flexible load cases, providing savings: 1,938 MW of battery storage in the Reference Case becomes 1,698 MW in the Flexible Loads Case



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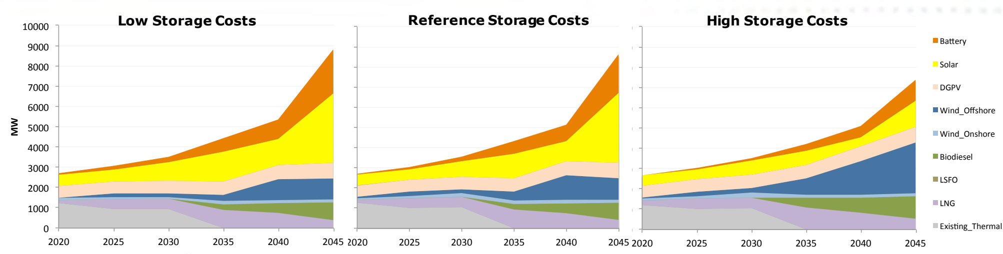
Renewable Integration Solutions: the Role of Storage



- **Given high costs, RESOLVE defers battery investment as long as possible.**
- **Through 2030, storage costs have little impact on the optimal build**
  - Less than 300 MW of batteries installed in all cases
- **Beyond 2030, the effect of storage costs on the optimal portfolio of renewables can be dramatic**
  - If battery costs decline substantially, RESOLVE will select more solar PV over offshore wind and biofuels.

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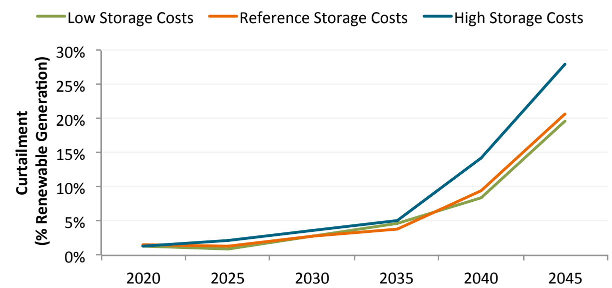
Renewable Integration Solutions: the Role of Storage



- **The expected curtailment over time mirrors the renewable build out schedule.**
- **Through 2030, storage costs have little impact on the optimal build**
  - Less than 300 MW of batteries installed in all cases
- **Beyond 2030, higher storage costs will lead to both less solar and higher expected curtailment**

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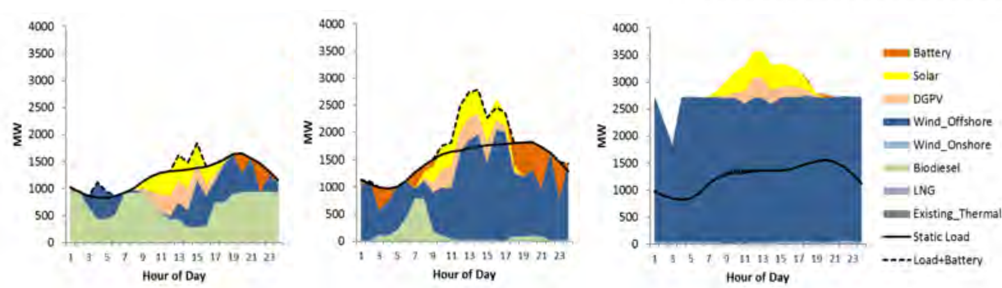
Integrating Wind

- **Unlike solar, which exhibits a diurnal generation pattern, wind does not follow a cyclical pattern**
- **Daily and seasonal variations in wind output can be large, posing balancing challenges**

Dispatch on Three Sample Days
Limited Solar Scenario
2045



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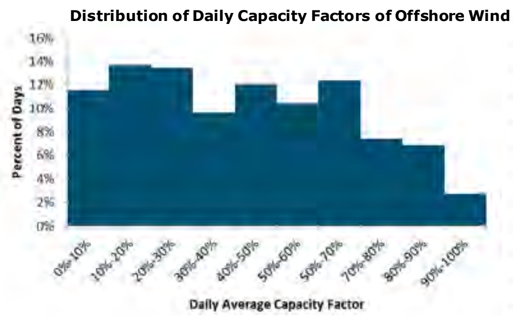
Integrating Wind

- **Solar curtailment can be readily addressed with batteries and flexible loads, which can provide daily balancing**
- **Providing balancing for wind probably requires integration solutions beyond batteries**
  - High-wind case is often paired with a produced decarbonized fuel like hydrogen



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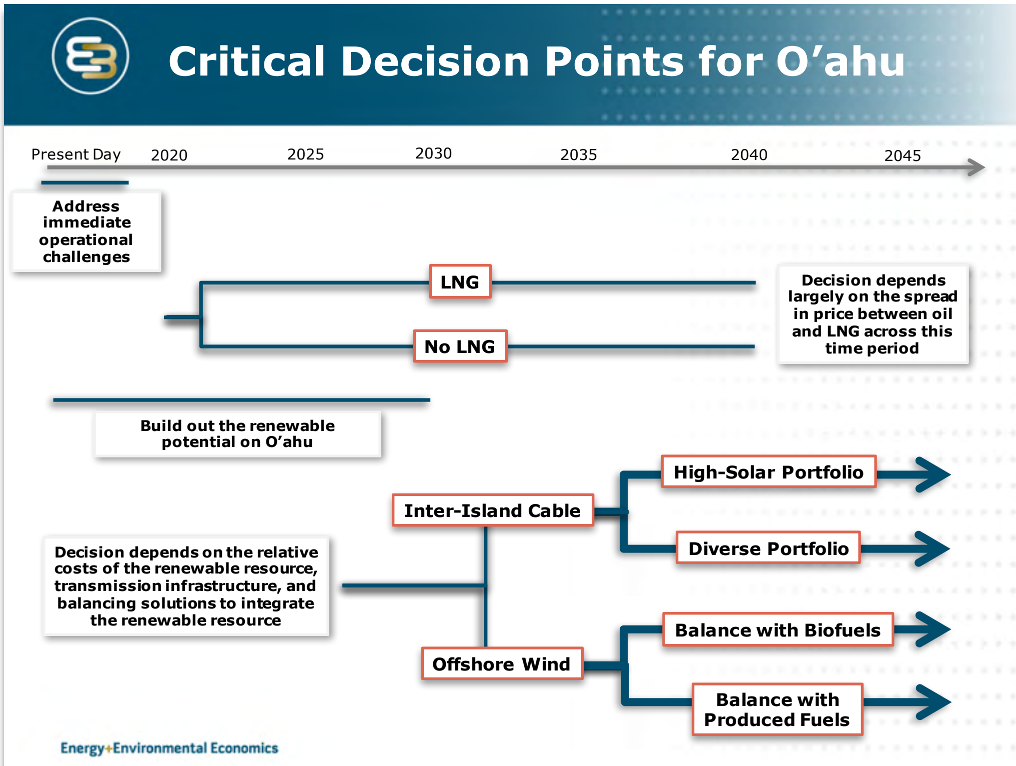

Potential Next Steps

+ Fully align E3's assumptions with HECO's and create process for validating assumptions
+ Use RESOLVE to calculate a breakeven fuel price spread to help commission decide about robustness of LNG decision
+ Develop an Inter-Island Cable case
+ Use RESOLVE to develop a least-cost plan that is not constrained to be compliant with the 100% RPS goal

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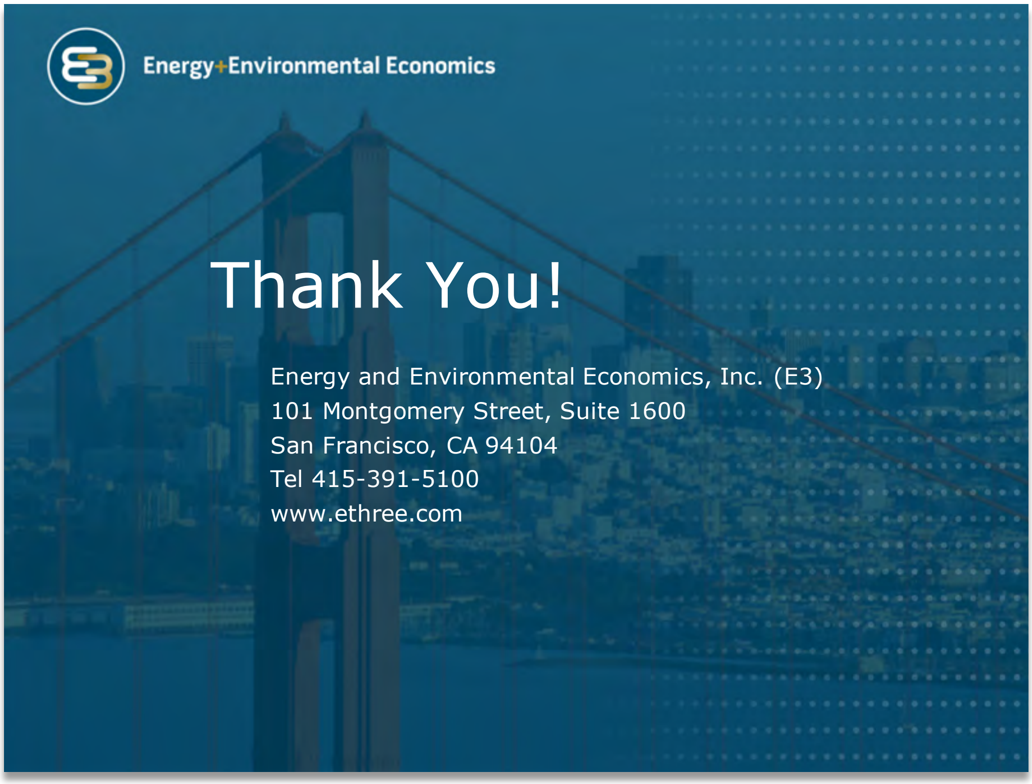
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Blue Planet Presentation: Third Stakeholder Conference

Consensus-Based Power System Planning Using Open Assumptions and Models

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- Renewable Energy and Island Sustainability (REIS)
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http://ee.hawaii.edu/~mfripp
http://github.com/switch-hawaii

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The Question

What kind of power system should we build over the next 30 years?

[2]

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The Process We've Been Using

- HECO makes investment plans inside a "black box"
- Community and PUC try to judge their merit
- Does not lead to consensus(!)
  - Plans are monolithic, and different options are hard to compare

[3]

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A Consensus-Based Approach

- HECO and stakeholders **agree on assumptions about the future**
  - Cost of renewable energy projects, fossil fuels and biofuels; screening rules for renewable energy projects; future renewable energy targets; possible range for these values; willingness to pay higher near-term costs to lower long-term risks
  - If stakeholders disagree on some assumptions, they can be used as sensitivity cases
- HECO and stakeholders **agree on optimization techniques** to choose the least-cost investment plan
- If we can agree on these smaller, more concrete questions, then **we get an overall plan we can agree on**

[4]

Proposal

- HECO works with stakeholders to agree on assumptions and questions *before* producing a plan
  - Have already made amazing progress with PSIPs
- HECO works with stakeholders to agree on modeling methods
  - E3 RESOLVE is a great step in this direction
- HECO produces optimal plans using these assumptions and methods
- Iterative process
  - Start with early data and preliminary results, then improve
  - If an "optimal" plan is implausible or unattractive, it's a starting point for constructive discussion and further analysis
    - Do we really want 30% biofuels? What would we build instead if we could only use 5%? How much would that cost?
  - Eventually, this framework can also be used for selecting RFP bids, judging prudency of investments, or even running a full-fledged capacity market

[5]

Data Recommendations

- More realistic screens for solar projects
  - No existing or proposed Oahu projects would meet the screens from 4/1/16 PSIP
  - 20%+ slope is possible at reasonable cost
  - Small parcels can be used and can be joined together (maybe 500 kW for smallest flat sub-parcel?)
- Consider using bulk electricity storage
  - Batteries, pumped storage hydro, hydrogen could all be cost-effective, depending on cost of other resources
  - Solar+storage option is especially important with high biodiesel prices

[6]

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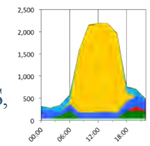
Use a State-of-the-Art Optimization Model as the Heart of Portfolio Selection

- SWITCH power system planning model
  - Written by Matthias Fripp in 2008
  - Now open-source, used and maintained by multiple contributors
  - Oahu version is now running with resource data based on PSIP, OWITS, HSIS, NREL NSRDB
  - All data and code are available from http://github.com/switch-hawaii
- Energy+Environmental Economics (E3) RESOLVE
  - Developed by E3 based on SWITCH
  - Strong team for framing analysis, preparing datasets and running the model
- No other capacity planning models can do this job
  - optimize multi-decade power system investments based on chronological, hourly behavior of renewables, storage and demand response



[7]

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SWITCH Model Design

Objective
- minimize total cost of electricity production in 2021–2052 (net present value)

Constraints
- policy constraints (RPS, MATS)
- provide enough electricity and reserves every hour
- physical limits of equipment and project sites

Decision variables (co-optimized)
- **Investments**: How much capacity to add of each technology
  - Wind, solar, fossil-fueled and hydro power plants; batteries and hydrogen storage; transmission
  - Investments occur in 2021, 2029, 2037 and 2045
- **Operation:** Power production or consumption by each project and responsive demand, each hour
  - 12-24 days of hourly behavior are modeled during each investment period
  - Follow-up production-cost model can test and plans using 8760+ hours

Open-source model and data available at http://www.switch-model.org

[8]

TASC Presentation: Third Stakeholder Conference

PSIP Chapter 9 "Next Steps"?

Addressing System Security with Renewable Spinning Reserves

THE ALLIANCE FOR SOLAR CHOICE

Overview

- Excess Energy
- Curtailment
- System Contingency Batteries
- Leveraging Solar Spinning Reserves

THE ALLIANCE FOR SOLAR CHOICE

Excess Energy

- Excess energy is an opportunity.
- Excess energy is a problem if you are not looking to leverage renewable resources to achieve 100% penetration.
- Renewable spinning reserves in significant quantity allows must run conventional generation to be shutdown.
- The only must run generation is renewable.

THE ALLIANCE FOR SOLAR CHOICE

Curtailment of DERs and utility scale renewables

- Utilizing curtailment as a utility tool ensures investments in utility scale system security batteries.
- Curtailment and ramp rate limits increase cost of renewables, increases consumption of fossil fuels, and decreases system reliability.

THE ALLIANCE FOR SOLAR CHOICE

Systems Contingency Batteries

- Large quantities of utility scale system security batteries are only needed at low renewable penetrations levels, *if* utility curtailment is a practice, and customer resources are not leveraged.
- Smart homes and businesses in conjunction with utility scale resistive frequency controls can provide the same services as a long term solution.

THE ALLIANCE FOR SOLAR CHOICE

Addressing System Security with Renewable Spinning Reserves

- Resources to unlock renewable spinning reserves
  - Resistive frequency control
  - Synchronous condensers
  - Flywheels and/or bulk energy storage
  - Smart homes and businesses
  - Significant investments in renewable resources

THE ALLIANCE FOR SOLAR CHOICE

Dynamic Resistive Frequency Control Unleashes Renewable Spinning Reserves

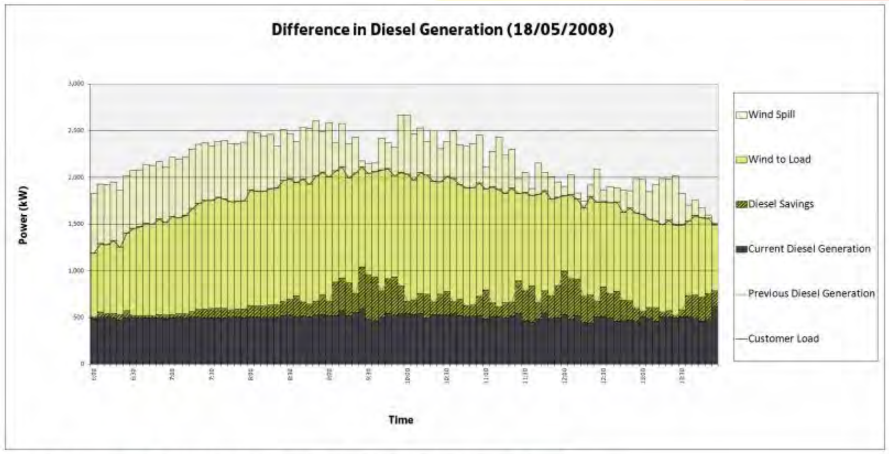

Figure 1: Comparison between current control method and new resistor control method

THE ALLIANCE FOR SOLAR CHOICE

Hydro Tasmania
The power of natural thinking

Morgan Stanley: Australian utilities underestimate disruptive power of solar+storage

- Australian utilities are underestimating the disruptive potential of solar-plus-storage technology, according to a new report from investment bank Morgan Stanley.
- The report estimates that solar and storage technology will be adopted four times more quickly in Australia than the country’s utilities expect.
- Morgan Stanley estimates battery storage will grow from about 2,000 Australian homes now to one million by 2020 or as high as two million homes by 2020 in its most optimistic estimate.
- http://www.utilitydive.com/news/morgan-stanley-australian-utilities-underestimate-disruptive-power-of-sola/421237/

THE ALLIANCE FOR SOLAR CHOICE

DBEDT Presentation: Third Stakeholder Conference

PSIP Comments and Next Steps

Chris Yunker

Energy Systems & Planning Branch Manager
Hawaii State Energy Office
Department of Business Economic Development and Tourism

PSIP Stakeholder Conference

Jun 28, 2016

HAWAII STATE Energy Office

PSIP Analytical Requirement

Questions to be answered for a PSIP Decision:

What are the **actions that need to be taken in the next 5 years** for Hawaii to achieve our objective of 100% renewables in 2045?

- Establishes prudency of the path forward

How much analysis, and **how detailed** does the analysis need to be, for the Commission **to reach a decision on elements within the 5 year plan**?

- Enough analysis and detail to reach a decision point on whether key elements that drive the 5 year action plan are prudent

What should the 5 year action plan provide?

- Guidance on the sequence of resource decision points such that the utility can solicit and acquire the resources over the next 5 years

It is not necessary to adopt the outer year portion of a roadmap to 100% renewables

What is important is to adopt a 5 year plan that can effectively accommodate multiple pathways to 100% renewables

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PSIP Remaining Scope

Gain a common understanding on the resource potentials, forecasts and constraints for each island to be analyzed

- Provide comprehensive list of resources the HECO Companies will include in the RESOLVE runs, which should be provided to stakeholders.
- Provide a template for collecting the information required to add a new resources, constraints, or forecasts in the RESOLVE model.

Develop a select number of scenarios for a capacity expansion model to run for each island and interconnected grid combinations

- Calibrate HECO's capacity expansion model with stakeholders who choose to run a capacity expansion model independently
- Establish breakeven cable costs to screen for viable scenarios, if any, to do further analysis on

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PSIP Remaining Scope (Cont.)

Establish what, if any, procurement actions within the 5 year action plan are impacted by a viable interconnected grid scenario

Establish what, if any, interconnected grid options are viable long run economic options to conduct further analysis on
(not required for a PSIP ruling, part of a PSIP ruling)

- Develop costs estimate for viable options that include the procurement, installation and interconnection of the undersea cable, as well as related grid upgrades.

If warranted **run capacity expansion model which includes interisland cable as a resource option**

- Identify candidate portfolios and key investments within the resulting 5 year plans

For candidate portfolios **construct case runs to analyze the discrete benefits and the drivers of those benefits for key investments** to support a Commission ruling of prudency

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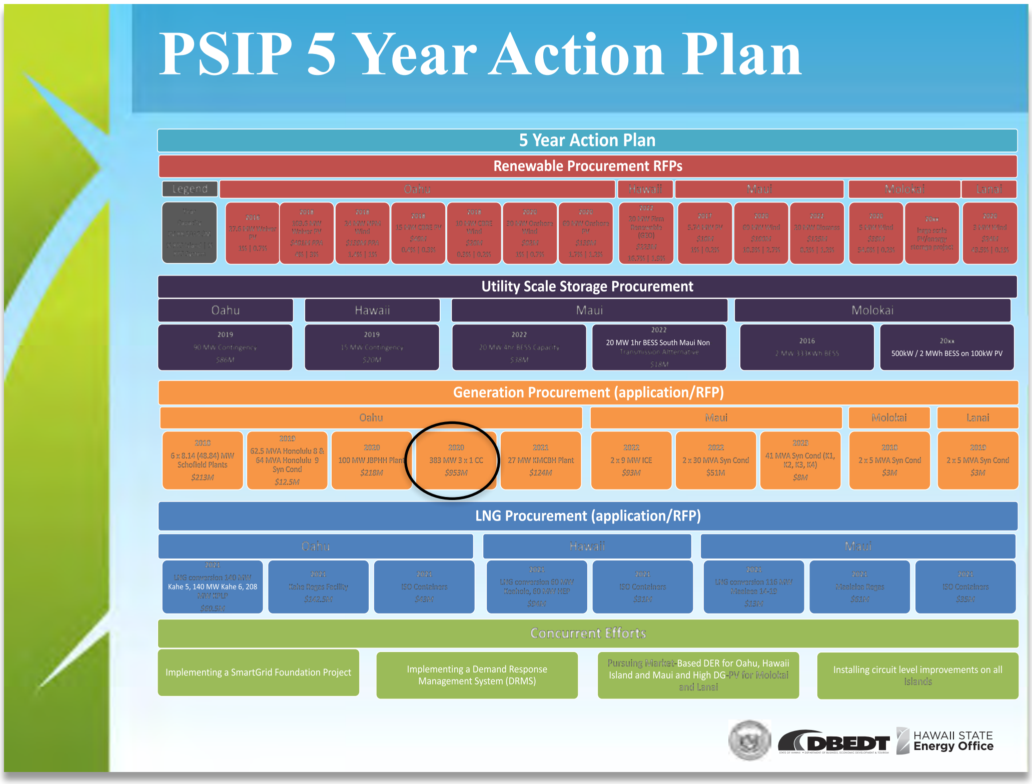
PSIP 5 Year Action Plan
5 Year Action Plan
Renewable Procurement RFPs
Utility Scale Storage Procurement
Oahu
Hawaii
Maui
Molokai
20 MW 1hr BESS South Maui Non
500kW / 2 MWh BESS on 100kW PV
Generation Procurement (application/RFP)
LNG Procurement (application/RFP)
Concurrent Efforts
Implementing a SmartGrid Foundation Project
Implementing a Demand Response Management System (DRMS)
Installing circuit level improvements on all islands
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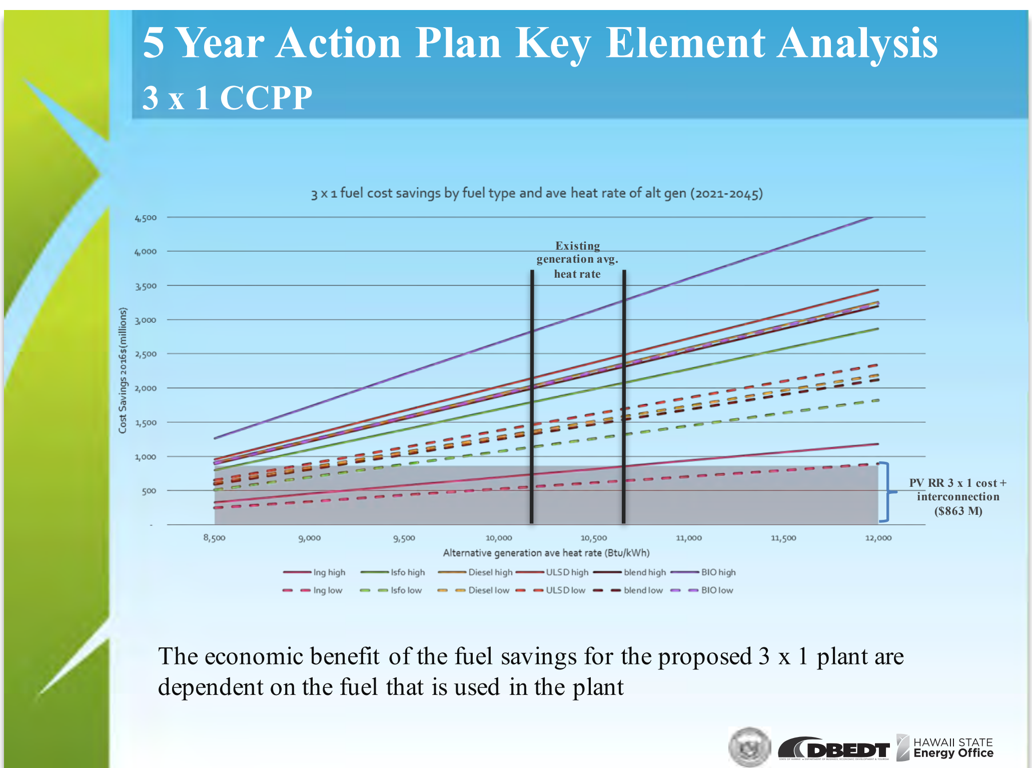
5 Year Action Plan Key Element Analysis
3 x 1 CCPP
3 x 1 fuel cost savings by fuel type and ave heat rate of alt gen (2021-2045)
Cost Savings 2016$ (millions)
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
Existing generation avg. heat rate
PV RR 3 x 1 cost + interconnection ($863 M)
8,500
9,000
9,500
10,000
10,500
11,000
11,500
12,000
Alternative generation ave heat rate (Btu/kWh)
lng high
lsfo high
Diesel high
ULSD high
blend high
BIO high
lng low
lsfo low
Diesel low
ULSD low
blend low
BIO low
The economic benefit of the fuel savings for the proposed 3 x 1 plant are dependent on the fuel that is used in the plant
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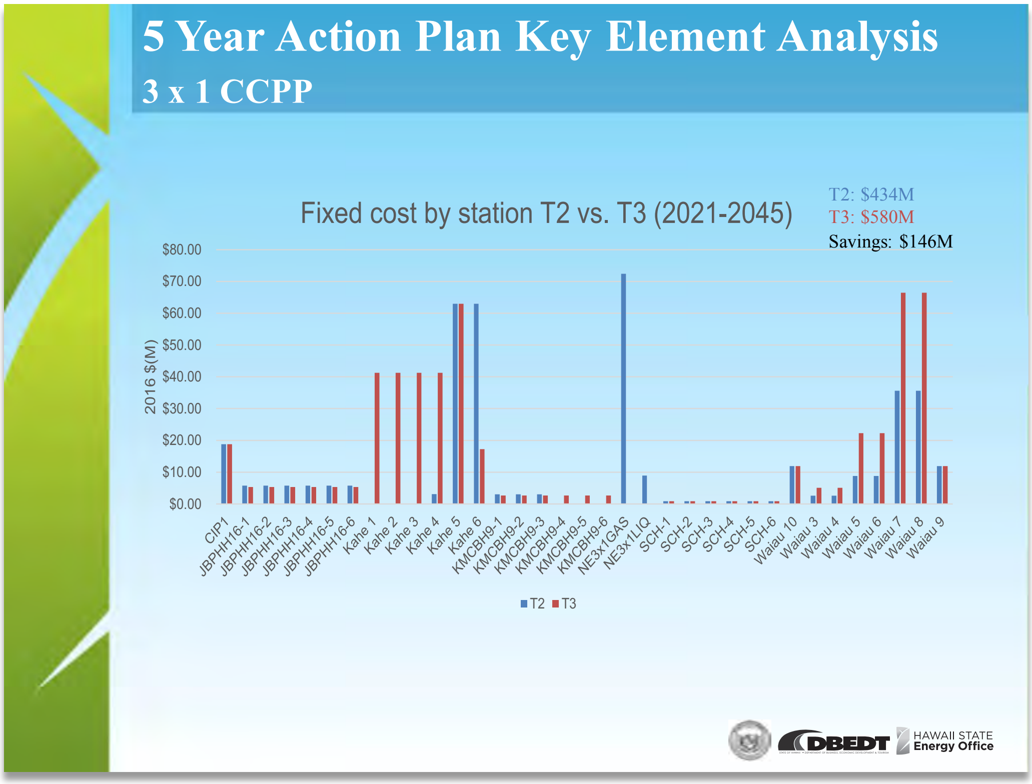
5 Year Action Plan Key Element Analysis
3 x 1 CCPP
Fixed cost by station T2 vs. T3 (2021-2045)
T2: $434M
T3: $580M
Savings: $146M
2016 $(M)
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
CIP1 JBPHH16-1 JBPHH16-2 JBPHH16-3 JBPHH16-4 JBPHH16-5 JBPHH16-6 Kahe 1 Kahe 2 Kahe 3 Kahe 4 Kahe 5 Kahe 6 KMCBH9-1 KMCBH9-2 KMCBH9-3 KMCBH9-4 KMCBH9-5 KMCBH9-6 NE3x1GAS NE3x1LIQ SCH-1 SCH-2 SCH-3 SCH-4 SCH-5 SCH-6 Waiau 10 Waiau 3 Waiau 4 Waiau 5 Waiau 6 Waiau 7 Waiau 8 Waiau 9
T2 T3
DBEDT
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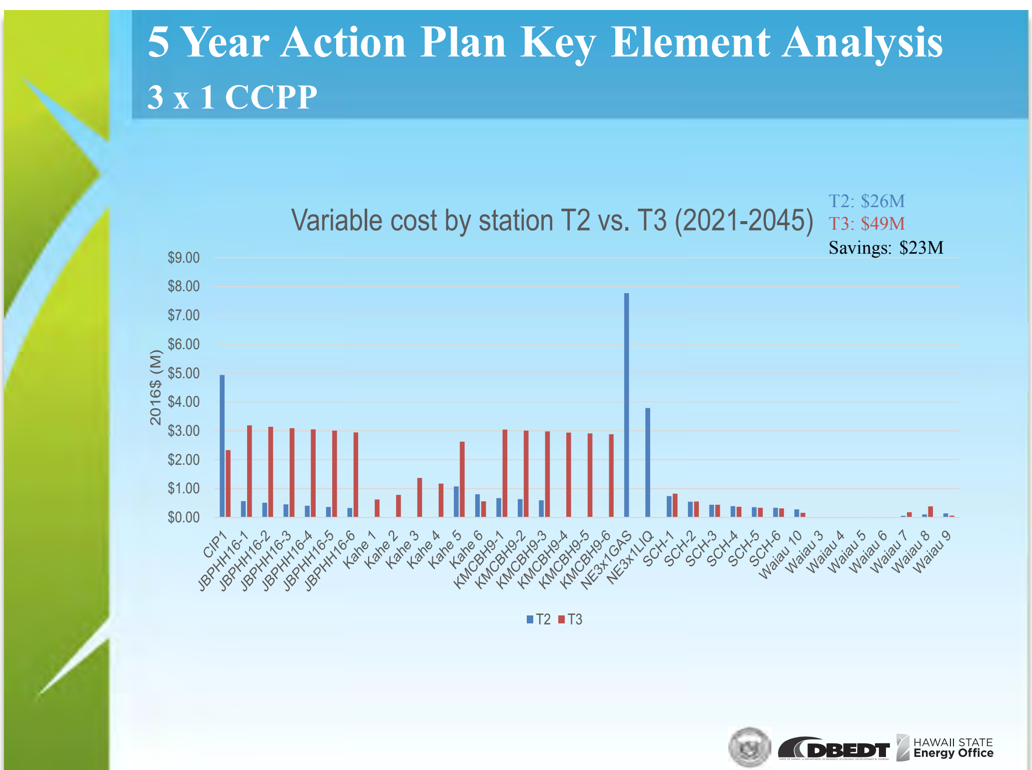
5 Year Action Plan Key Element Analysis
3 x 1 CCPP
Variable cost by station T2 vs. T3 (2021-2045)
T2: $26M
T3: $49M
Savings: $23M
2016$ (M)
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
CIP1 JBPHH16-1 JBPHH16-2 JBPHH16-3 JBPHH16-4 JBPHH16-5 JBPHH16-6 Kahe 1 Kahe 2 Kahe 3 Kahe 4 Kahe 5 Kahe 6 KMCBH9-1 KMCBH9-2 KMCBH9-3 KMCBH9-4 KMCBH9-5 KMCBH9-6 NE3x1GAS NE3x1LIQ SCH-1 SCH-2 SCH-3 SCH-4 SCH-5 SCH-6 Waiau 10 Waiau 3 Waiau 4 Waiau 5 Waiau 6 Waiau 7 Waiau 8 Waiau 9
T2 T3
DBEDT
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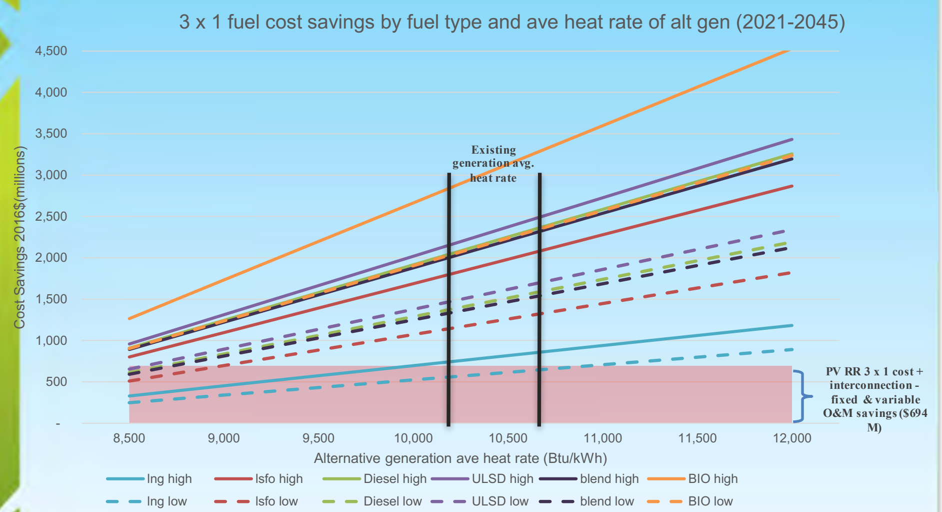
5 Year Action Plan Key Element Analysis

3 x 1 CCPP



There are other additional benefits, alternative fuel price forecasts and potential alternative resources which will have an impact on whether or not a 3 x 1 CCPP is prudent

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In Summary

The 5 year action plan and the guidance it provides is what should be adopted in a PSIP ruling

- The remaining pathway to 100% is simply to show the 5 year action plan is prudent

There needs to be a clearly agreed upon analytical scope, analytical process and supporting procedural timeline that allows for the completion of the PSIP

- Expansion model to assure relevant candidate portfolios are identified
- Case runs to understand the drivers of costs and benefits for alternative candidate 5 year action plans

There needs to be a detailed breakdown of costs and benefits presented for key elements in the 5 year action plan so that a decision point to move forward can be reached

- Detailed costs for specific resources would be part of an application

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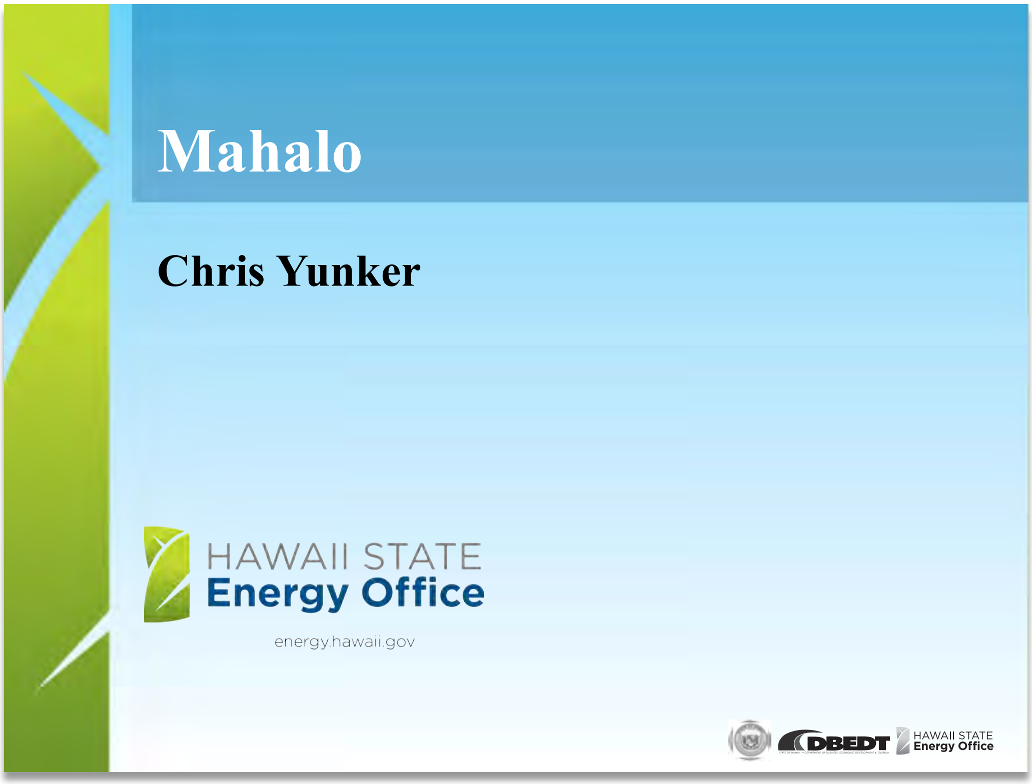

Mahalo
Chris Yunker
HAWAII STATE
Energy Office
energy.hawaii.gov
DBEDT
HAWAII STATE
Energy Office

Ulupono Initiative Presentation: Third Stakeholder Conference

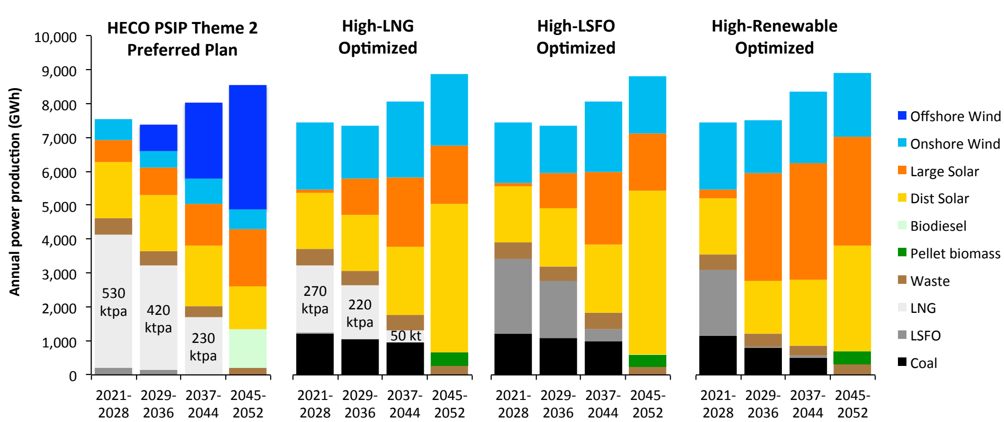
Valuing Risk Matters

- Renewable Power are a hedge against fossil fuel risk
- Quantitatively incorporating risk can lead to new conclusions regarding the optimal resource mix
- We are presenting two approaches:
  - Monte Carlo
  - Market Based Hedge

We propose a path forward to understand of our situation and the tradeoffs of our choices

ulupono INITIATIVE

Selected Power System Designs - Energy



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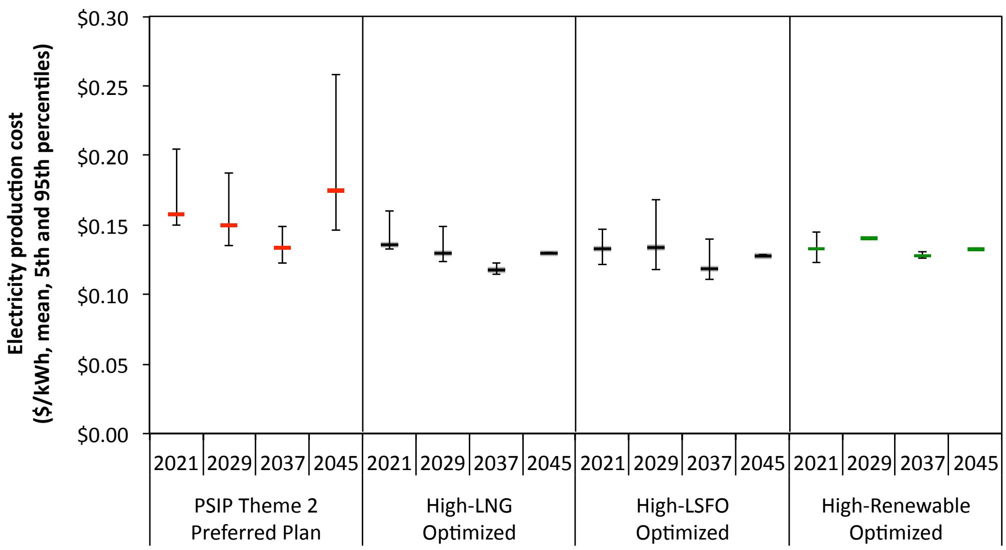
Potential Electricity Costs and Risk



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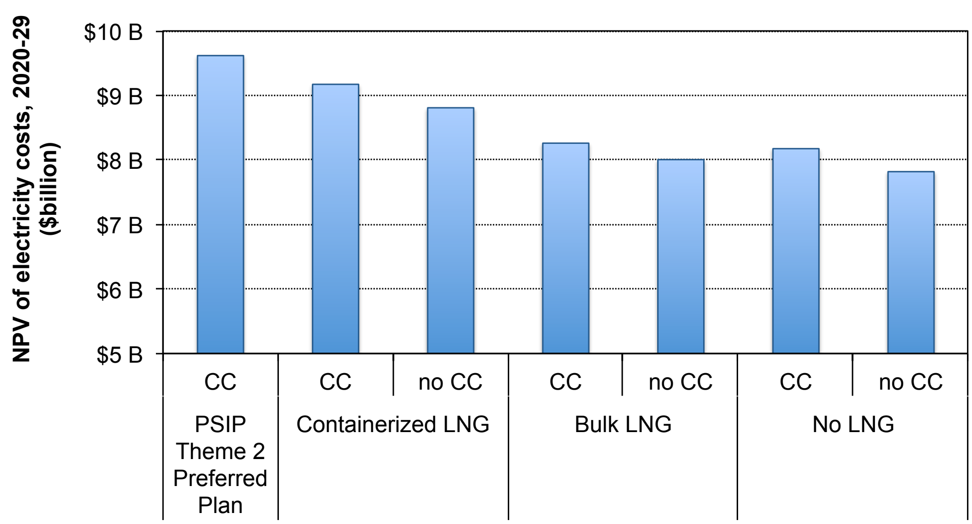
Cost of Optimal "Risk-Free" Power Systems



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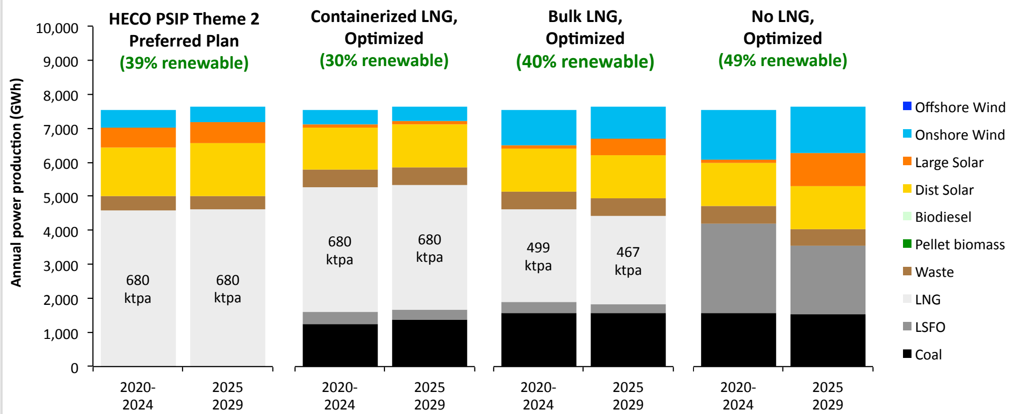
Optimal Power System Operation, Without New Combined Cycle Plant



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Recommended Next Steps

- To extent not addressed in PUC Order 33320, Commission provides detailed guidance for revised PSIPs
- Commission Technical Session re:
  - Modeling, data parameters and assumptions, nature and extent of data used by RESOLVE model
  - Agreement on using modified RESOLVE model, on a transparent basis, to:
    - identify 3-5 alternative generation resource mixes to achieve 100% clean energy by 2045. with 5-year action plan
    - identify key decision Commission must make to implement each plan, with major tradeoffs, costs, risks benefits, minimization of foreclosure of future options
  - Information requests (limited number, scope) before and after Technical Session
- Commission appoints Independent Entity to oversee finalizing PSIPs
- HECO Companies finalize PSIPs, based on results of modified RESOLVE models, participation by parties, submit same to Commission
- Commission asks parties to provide short brief recommending which proposed PSIP plan should be the preferred plan and action plan
- Commission decides whether to accept the PSIPs and alternative plan
- Commission sets future formal review dates, process for input from the parties and the public

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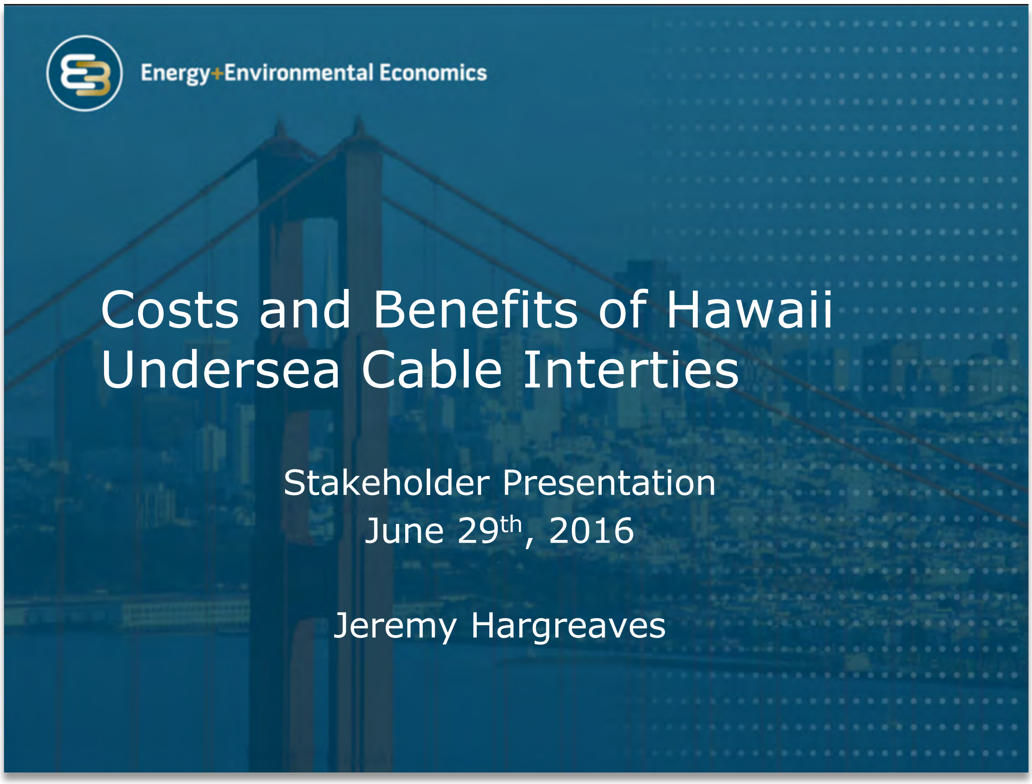
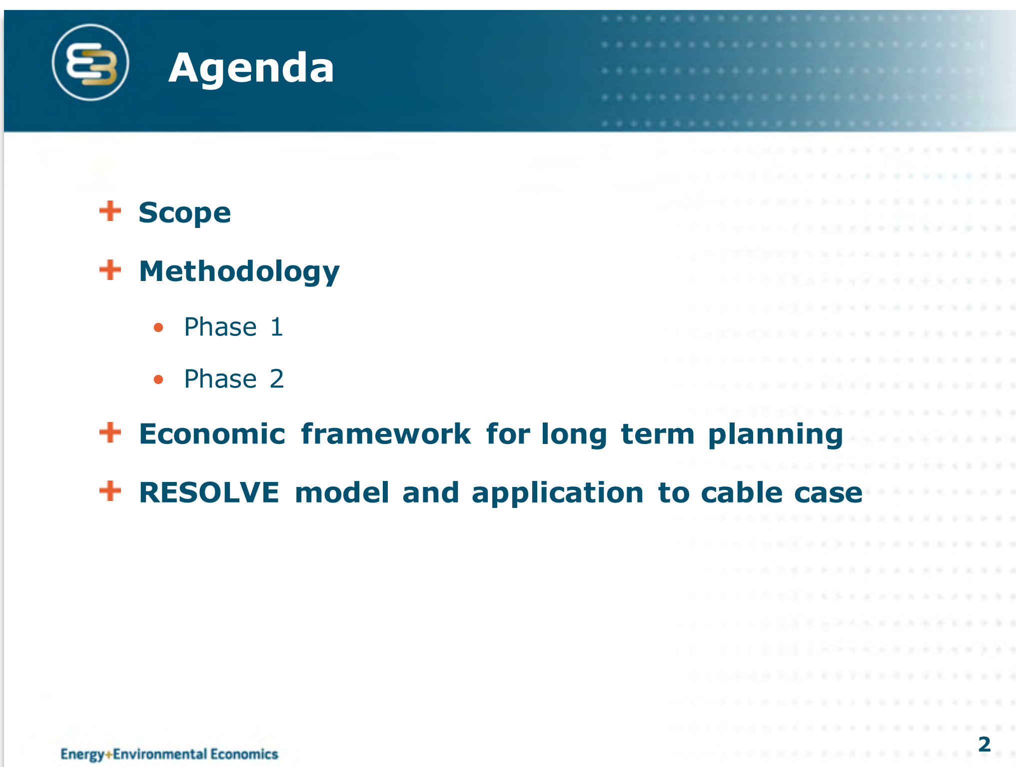
E3 Presentation: Third Stakeholder Conference





Scope

- **Determine cost effectiveness of undersea interties between the Hawaiian islands**
  - Relative to other policy options for reaching RPS targets
  - Subject to sensitivities on fuel and technology pricing
- **Two phases of the study**
  1. Compare the cost of a copper plate transmission case between O'ahu, Maui and the Big Island with the cost of each island going it alone
  2. If the potential savings from phase 1 justify further study, determine cable costs and refine the benefits with greater detail around cable capabilities

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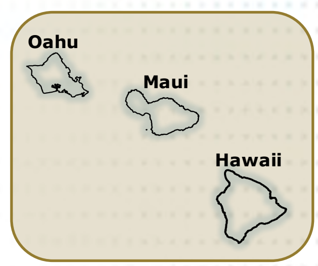
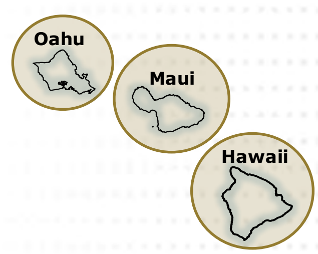
Phase 1 Methodology

1. **'Copper Plate' case**
   - Determine the least cost resource plan to meet RPS targets with unlimited transmission between islands
   - Model Islands as a single zone



2. **'Go it Alone' case**
   - Analyze the islands separately. Supplement the O'ahu plan from the PSIP with Maui and Big Island studies
   - Calculate a total cost of meeting the RPS without interconnection



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Phase 1 Methodology

- **Determine the breakeven costs of the copper plate**
  - Savings of case 1 over case 2 represent the cost of cables at which Hawaii would breakeven
  - Theoretical maximum benefits from cable interconnections given unlimited transmission modeled
- **Are savings high enough to justify further study?**
  - If breakeven costs are higher than rough estimates of cable costs, we will proceed to Phase 2
- **Impacts of the cable case on resource selection**
  - How does the cable affect the value of LNG and other resources selected in 'Go it Alone' case?

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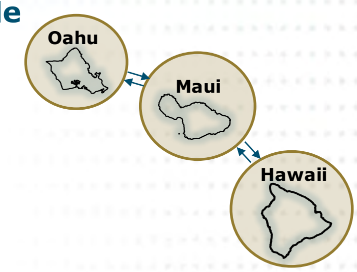
Phase 2 Methodology

- **Develop cost estimates for the cable interties**
  - Work with HECO and engineers to develop intertie alternatives and pricing
- **Modeling refinement**
  - Model the transmission constraints of each of the intertie options
  - Find the benefits of each intertie option
  - Determine the least cost option and how it compares against other policy alternatives
  - Test robustness against sensitivities on key inputs



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Economic framework to select optimal resource portfolios for cable intertie comparison

E3 RESOLVE

- **Question: How to navigate the many policy and resource options available to meet RPS goals?**

- **E3 RESOLVE is an optimal investment planning model**
  - Selects least-cost resource portfolio and integration solutions to meet RPS targets
  - Considers all resource options on level playing field
  - Evaluates long-term benefits of investments as renewable portfolio evolves over time
  - Allows investigation of new policy and regulatory reforms
- **Complementary approach to detailed production simulation modeling**
- **Helps make sense of the growing state space of options in high renewable systems, including cable interties**

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Renewable integration solutions

- **Various solutions have been proposed, with different performance characteristics and costs**
  - Energy storage (batteries, etc.)
  - Flexible loads or advanced DR
  - Flexible resources (new flexible CCGTs, Aero CTs, Reciprocating Engines or retrofits to existing plants)
  - Tariff design, regulatory and market changes
  - Renewable resource diversity
  - Increased transmission

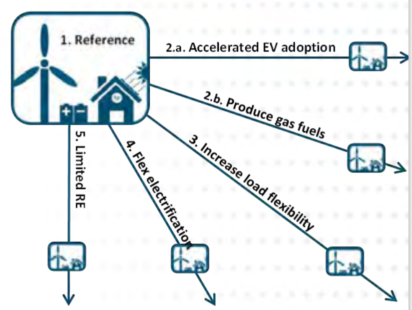
http://www.theiet.org/membership/member-news/31a/ev-charging-course.cfm

http://allthingsd.com/files/2012/10/Nest-Cooling-2.jpg

9

Establish potential future scenarios

- **Optimal expansion planning models can be used to investigate how system planners should respond in different policy or price driven scenarios**
  - Determines optimal investments within the constraints of a defined potential future policy world
- **Building cables is one potential policy for Hawai'i**



- **Establish a set of plausible policy scenarios for Hawai'i**
  - Includes 'Copper Plate' and 'Go it Alone' cases in Phase 1
- **Determine the optimal resource investments in each policy case, subject to sensitivities around fuel and technology costs**

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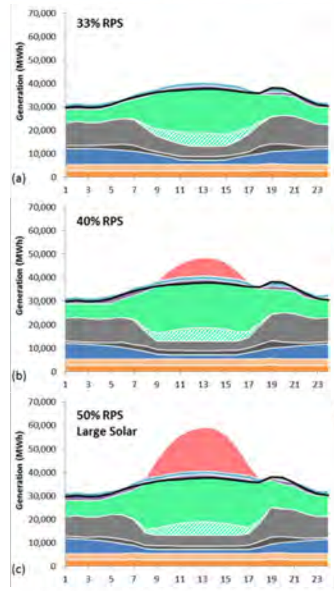
The renewable integration challenge

- **Primary drivers of renewable integration challenges at high penetrations:**
  - Renewable oversupply during low load periods
  - Inflexible conventional generation
    - Must-run resources
    - Self-scheduled resources/contract limitations
    - Technical constraints on ramping, minimum stable levels, minimum up and down times
    - High costs associated with cycling
  - Small balancing areas where diversity of renewables is limited, and generator fleets are constrained



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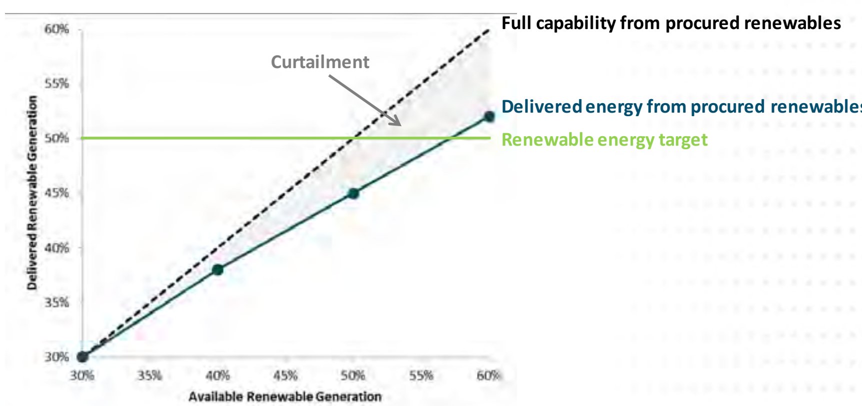
Economics of renewable integration

- **The consequence of failing to supply enough flexibility to integrate renewables is renewable curtailment, or reliability issues**



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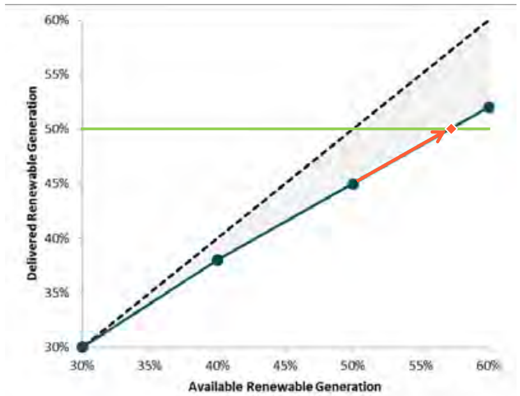
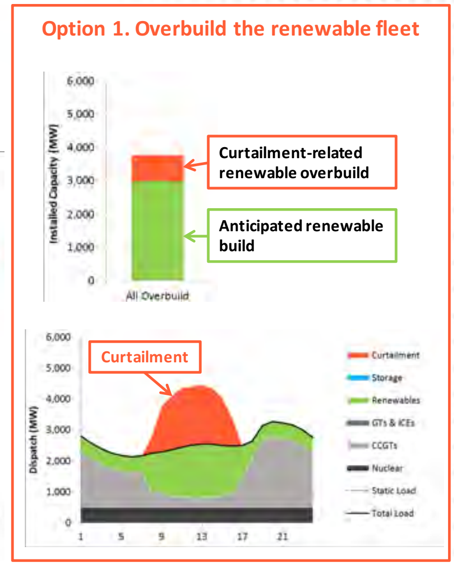
Option 1. Overbuild renewables

+ **Overbuilding the renewable fleet allows for policy goal to be met with some allowance for curtailment**





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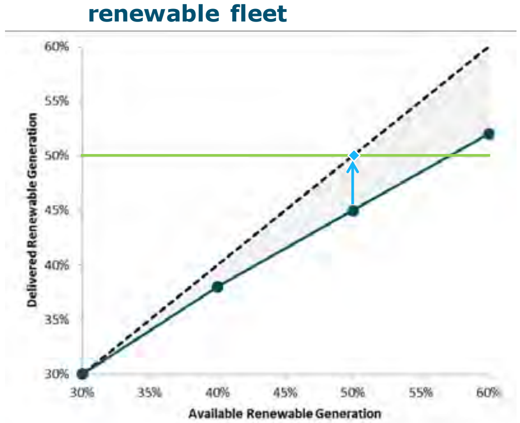
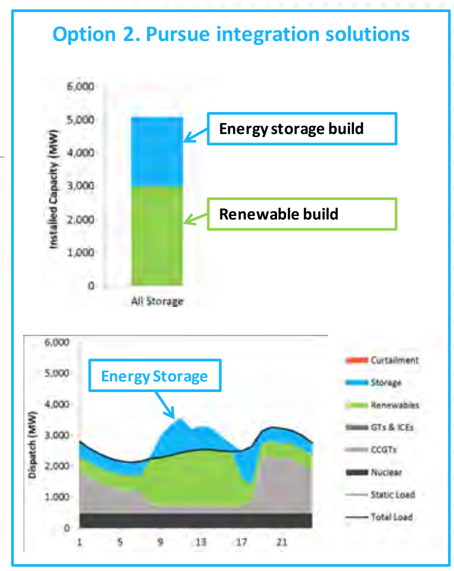
Option 2. Pursue integration solutions to avoid overbuild

+ **Integration solutions (eg. storage, balancing area consolidation) permit more effective delivery of existing renewable fleet**





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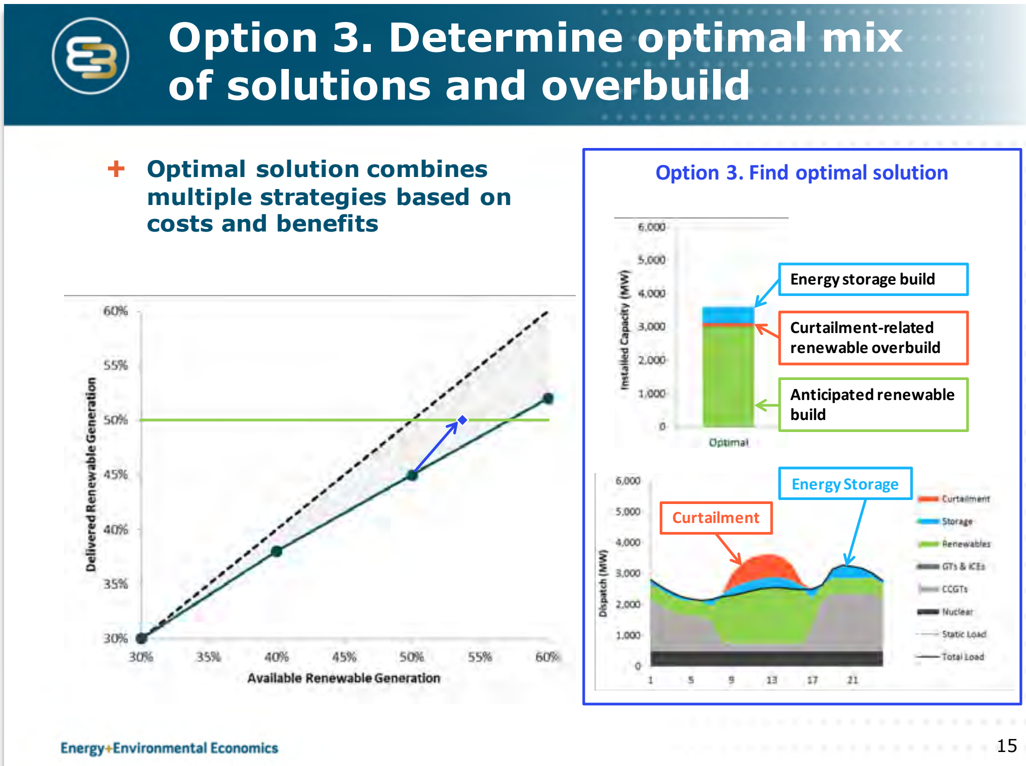
14


Option 3. Determine optimal mix of solutions and overbuild
+ Optimal solution combines multiple strategies based on costs and benefits
Delivered Renewable Generation
Available Renewable Generation
Option 3. Find optimal solution
Installed Capacity (MW)
Energy storage build
Curtailment-related renewable overbuild
Anticipated renewable build
Optimal
Dispatch (MW)
Energy Storage
Curtailment
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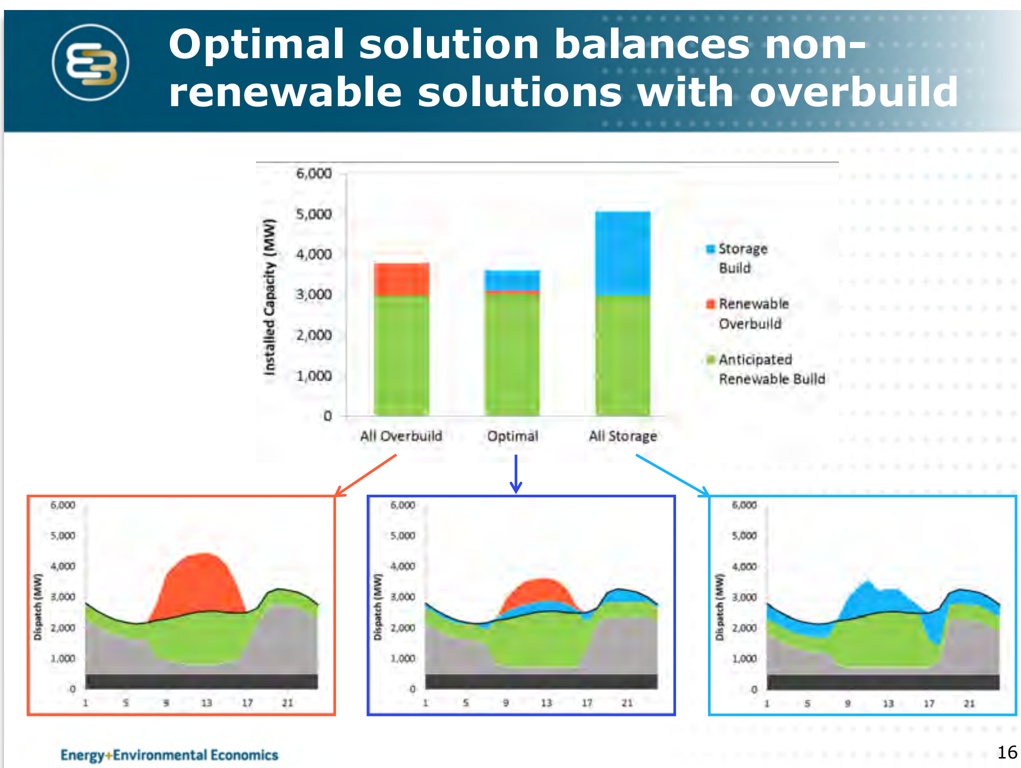
Optimal solution balances non-renewable solutions with overbuild
Installed Capacity (MW)
Storage Build
Renewable Overbuild
Anticipated Renewable Build
All Overbuild
Optimal
All Storage
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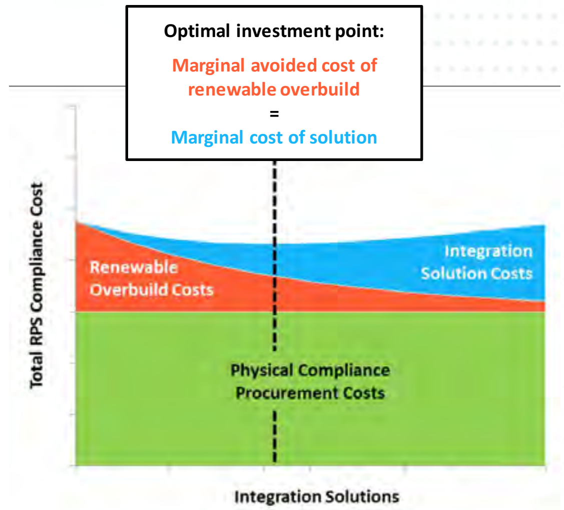
16

Identifying optimal investment in solutions

- **Single solution case:**
  - The cost of the solution can be weighed against the avoided cost of overbuilding renewables for RPS compliance
- **Multiple solution case:**
  - Multidimensional optimization
  - Complex interactive effects
  - **Requires models that treat both operations and investment costs**
    - SWITCH and RESOLVE are examples of such models



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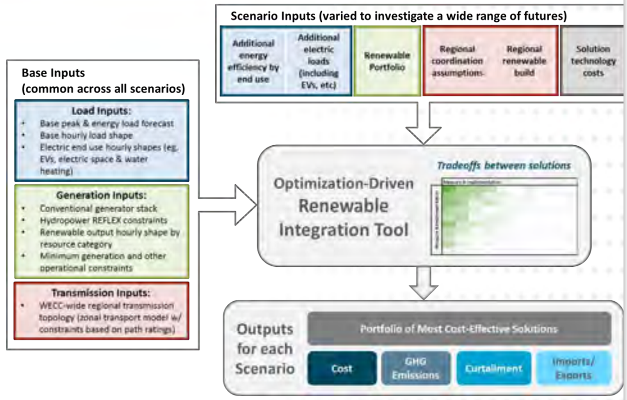
RESOLVE Model

RESOLVE Modeling Framework

+ **Co-optimizes investment and operational decisions over multiple years**
  - Can solve for optimal investments in renewable resources, energy storage, conventional generators
  - Can test value of solutions with unknown or uncertain supply curves, like flexible loads & time-of-use rates



+ **Operational detail focuses on primary drivers of renewable integration challenges**
  - Hourly dispatch with reserve and operating constraints
  - Zonal treatment of interconnection to model flows with increased granularity in primary zone of study

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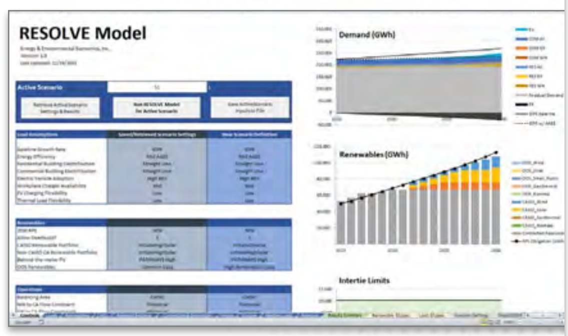
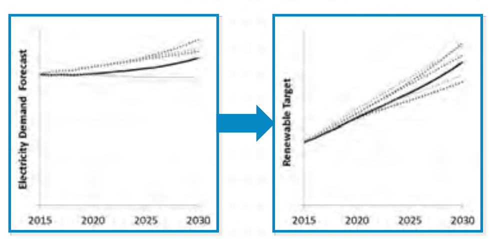
Scenario-based analysis produces more robust conclusions

+ **Scenarios determined by:**
  - Loads by subsector, including residential and commercial thermal loads, electric vehicle adoption, & energy efficiency
    - Dynamically-updated hourly load shapes
  - Renewable policies
    - RPS targets and behind-the-meter PV adoption
  - Renewable resource costs and potentials
  - Costs
    - Renewable, conventional, and storage technology costs, transmission costs
    - Fuel prices





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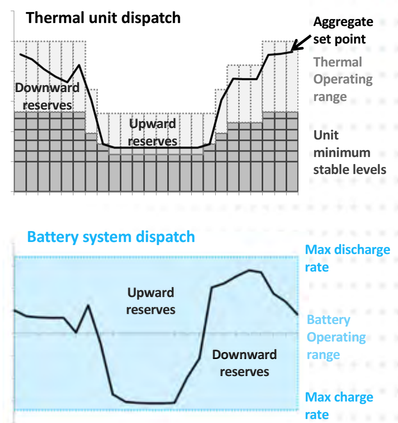
Detailed hourly model brings operational challenges into investment decisions

- **For each year in the simulation, a subset of days are selected and weighted to reflect long-run distributions of:**
  - Daily load, wind, and solar
  - Monthly hydro availability (in CA)
- **Operations modeled using linear dispatch formulation**
  - MIP possible for small systems or when runtime is not a constraint; linear approximations for large systems
  - Upward and downward operating reserve constraints

Simulates economic dispatch on each day subject to technical operating constraints



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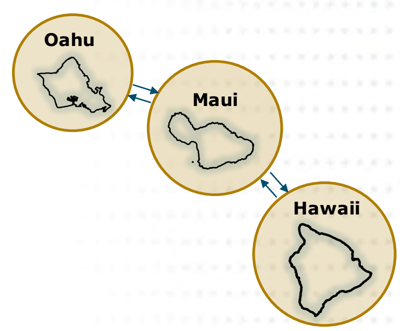
Zonal dispatch treatment enables study of flow constraints between islands

- **Each zone:**
  - Optimal investment decisions
  - Detailed treatment of operating reserves, depending on cable option modeled
- **Detailed representation of flow constraints**
- **Flows may be impacted by:**
  - Min and max intertie flow constraints
  - Min and max simultaneous flow constraints for groups of interties
  - Ramping constraints on interties
  - Hurdle rates



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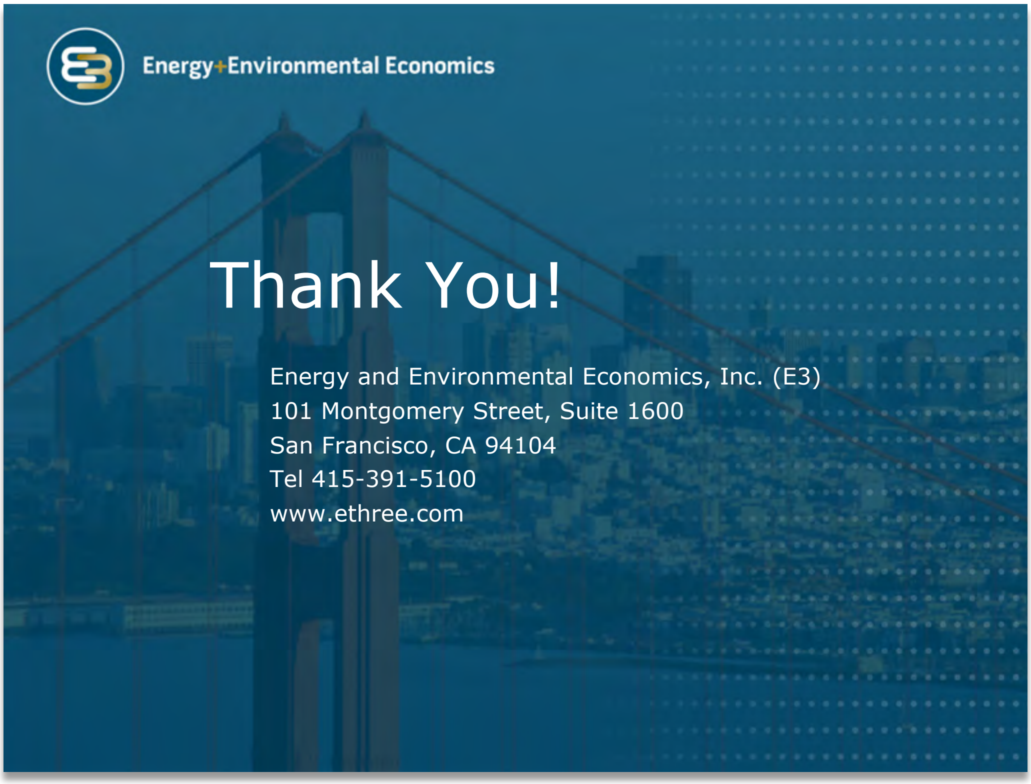
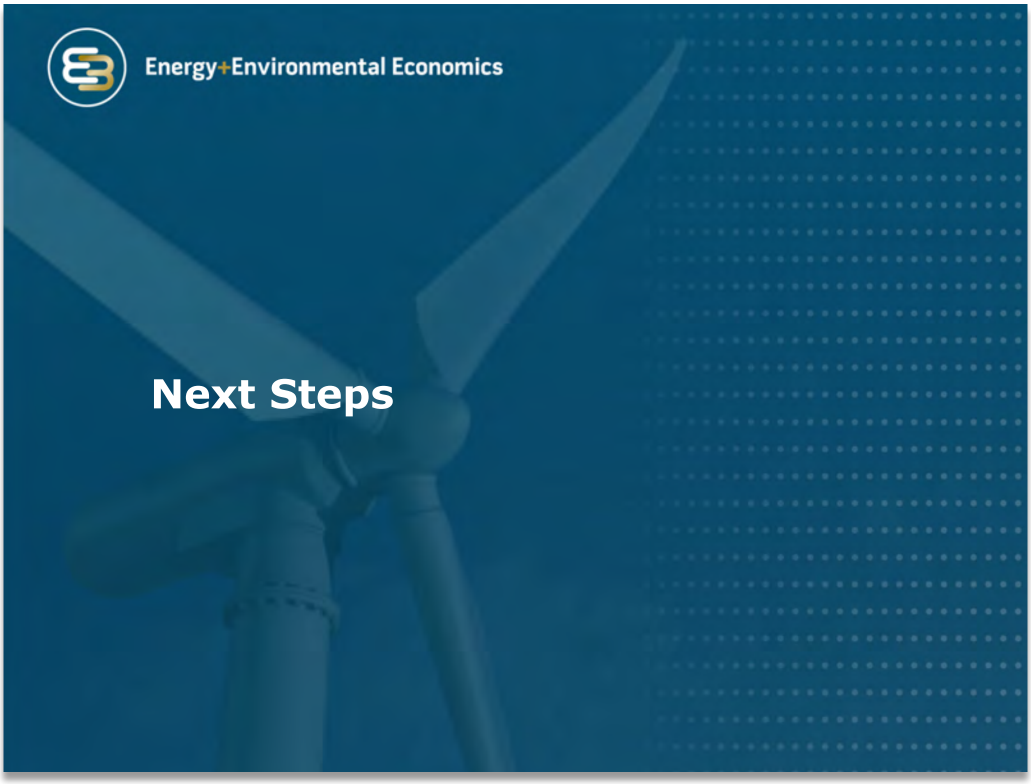

Energy+Environmental Economics
Thank You!
Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
www.ethree.com


Energy+Environmental Economics
Back-up Slides



Potential Next Steps

+ **Phase 1 underway - aligning E3's assumptions for each island with HECO's**
+ **Next steps:**
  - Produce 'Copper Plate' and 'Go it Alone' cases for assessment of cable breakeven cost
  - Assess the viability of cable interconnection and need for Phase 2
  - Establish the process and timing for stakeholder comments

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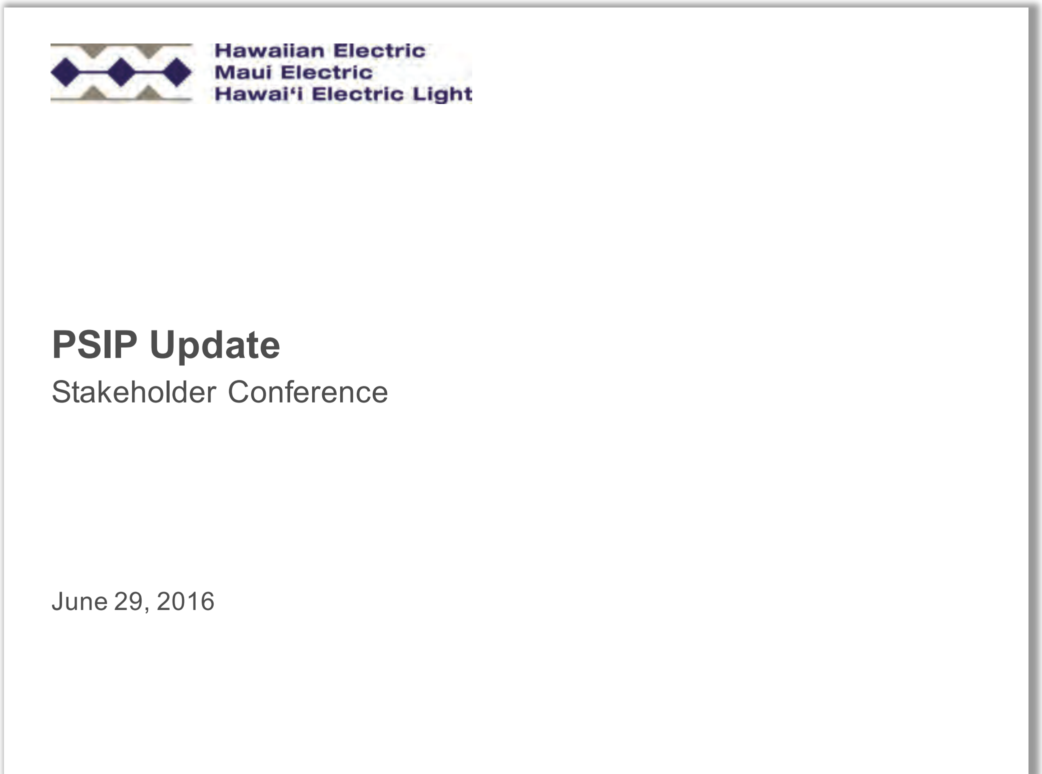
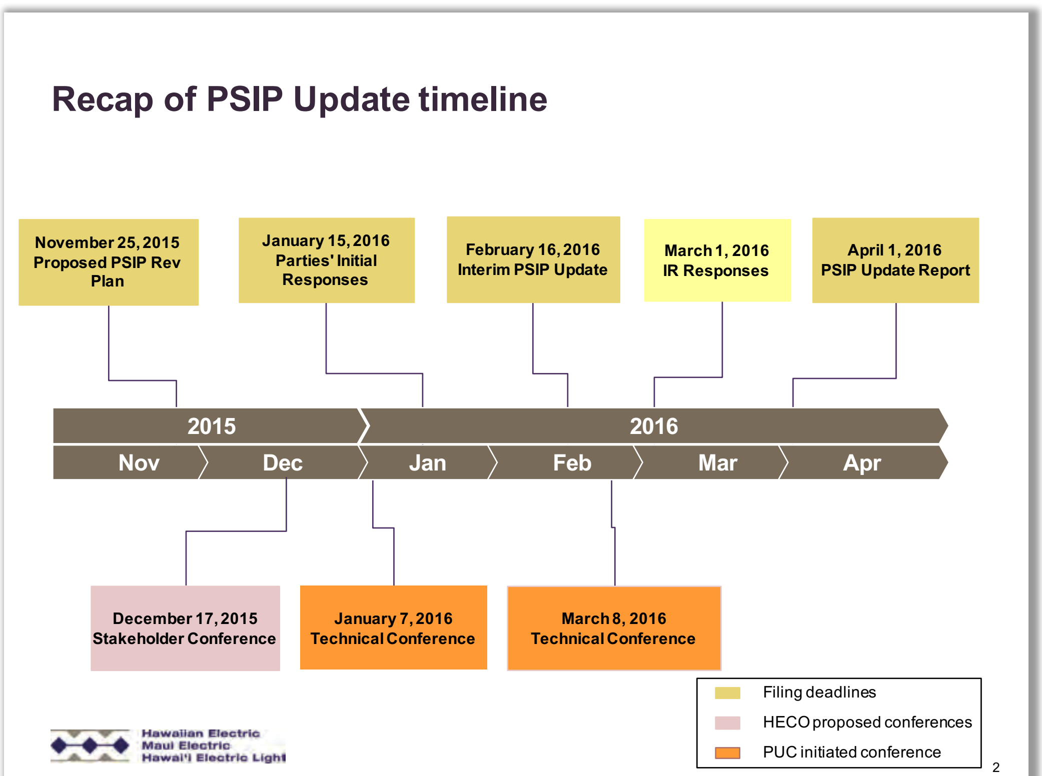
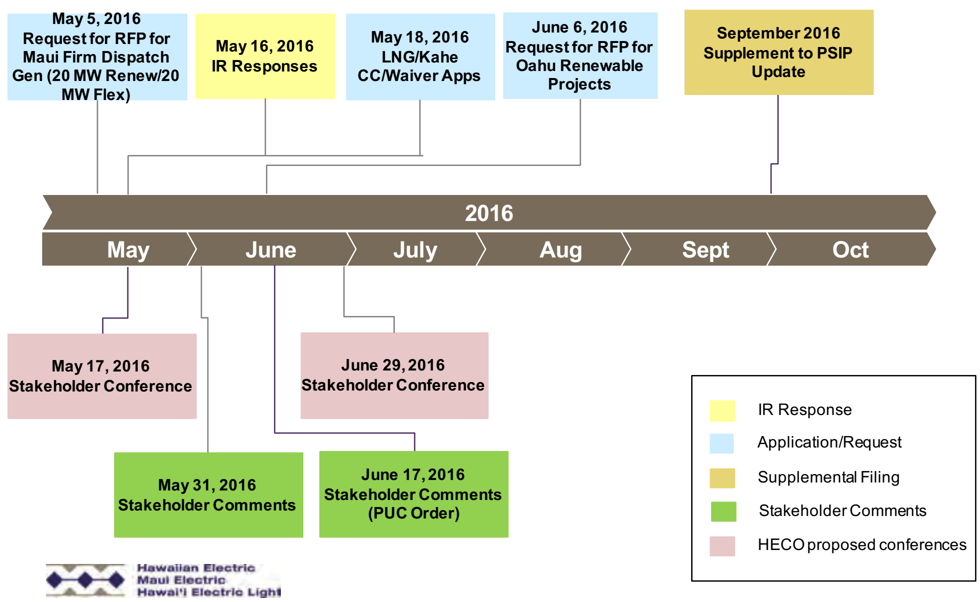
Hawaiian Electric Presentation: Third Stakeholder Conference





Recap of PSIP Update timeline



Hawaiian Electric
Maui Electric
Hawai'i Electric Light

3

Participant Cost Information

- SunPower
  - Utility and Residential PV Costs
  - Utility and Residential BESS Costs
  - Adjusted for comparative analysis
    - Costs relatively close
    - Residential BESS costs comparable
- Hawaii Gas
  - Provided 2 fuel price forecasts
    - 100% Brent basis
    - 50% Brent / 50% Henry Hub basis
  - Commodity forecast different than PSIP
  - Requested clarifications to perform comparative analysis

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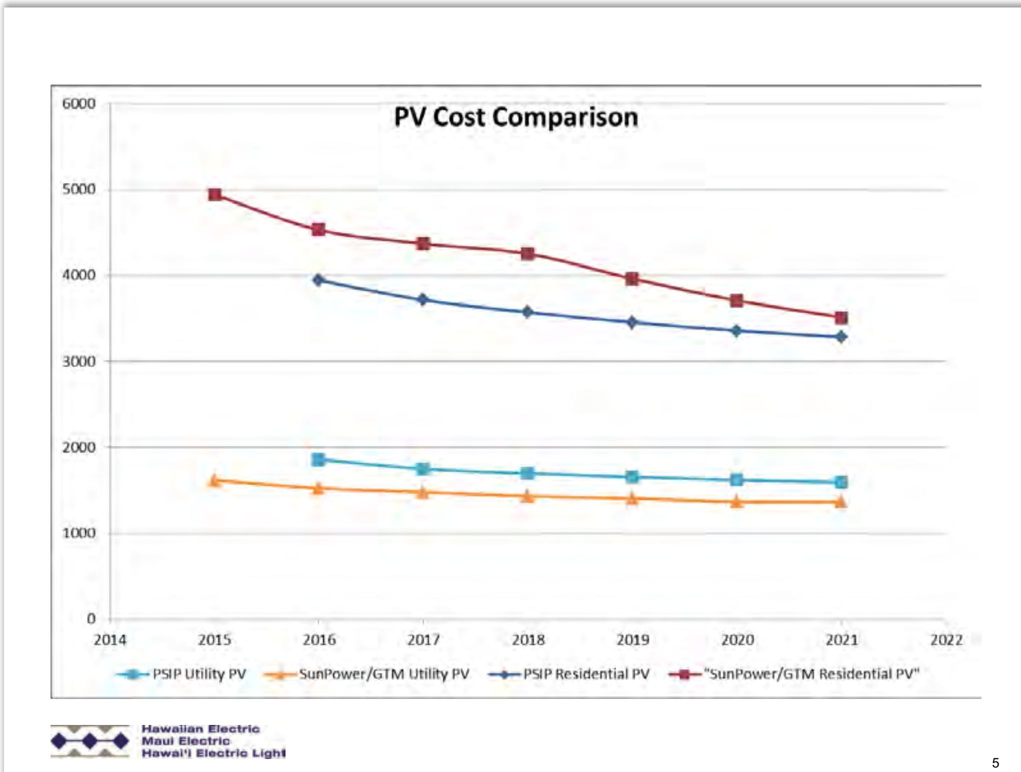
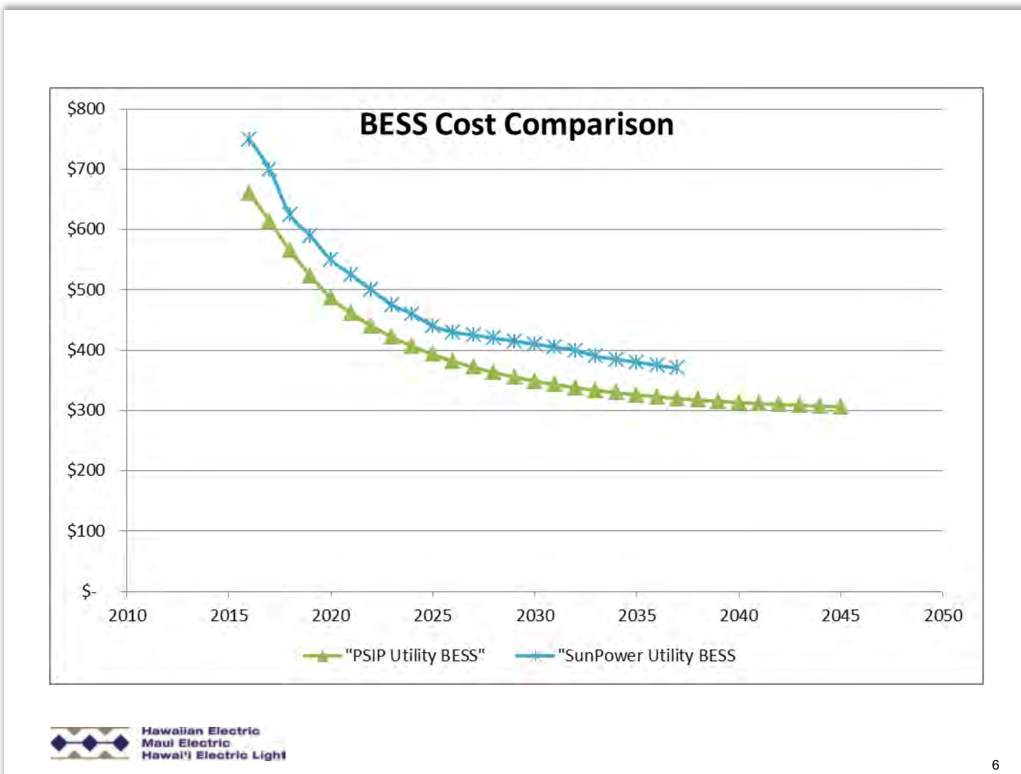
Hawai'i Electric Light

4


PV Cost Comparison
6000
5000
4000
3000
2000
1000
0
2014
2015
2016
2017
2018
2019
2020
2021
2022
PSIP Utility PV
SunPower/GTM Utility PV
PSIP Residential PV
"SunPower/GTM Residential PV"
Hawaiian Electric
Maui Electric
Hawai'i Electric Light
5


BESS Cost Comparison
$800
$700
$600
$500
$400
$300
$200
$100
$-
2010
2015
2020
2025
2030
2035
2040
2045
2050
"PSIP Utility BESS"
"SunPower Utility BESS
Hawaiian Electric
Maui Electric
Hawai'i Electric Light
6

Next Steps

- Update Analysis
  - New EIA AEO Fuel Price Forecast (Early Release May 17, 2016; AEO 2016 July 7, 2016)
  - Updated Resource Costs (ITC, Biomass)
  - Further Refinements if possible
  - Update Production Simulations and Cost Analyses
  - Sensitivity Analyses using Alternative Pricing Provided by Parties (input no later than 7/6/16)
- Perform Additional System Security Analyses
  - Perform analysis for contingency BESS (FFR1) for Oahu, Maui, and Hawaii Island
- Identify Alternatives and Analyze Inter-Island Transmission
  - E3 Break-even analysis

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7

Next Steps

- Evaluating Feasibility of Offshore Wind Resources with consideration of Bureau of Ocean Energy Management (BOEM) process
- Complete LNG Risk Premium Analysis
  - Ascend Analytics (stochastic analysis)
- Complete Sub-hourly Analysis
  - Refine storage analysis
- Update System-level Hosting Capacity Analyses
- **Revised Estimated Completion: September 30, 2016**

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8

Ulupono Presentation: Fourth Stakeholder Meeting

PSIP Data Recommendations

PSIP Stakeholder Meeting
October 19, 2016

Matthias Fripp
University of Hawaii Economic Research Organization (UHERO)
Renewable Energy and Island Sustainability (REIS)
Asst. Prof. of Electrical Engineering
University of Hawaii at Manoa
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OAHU RENEWABLE RESOURCE ASSESSMENT

[2]

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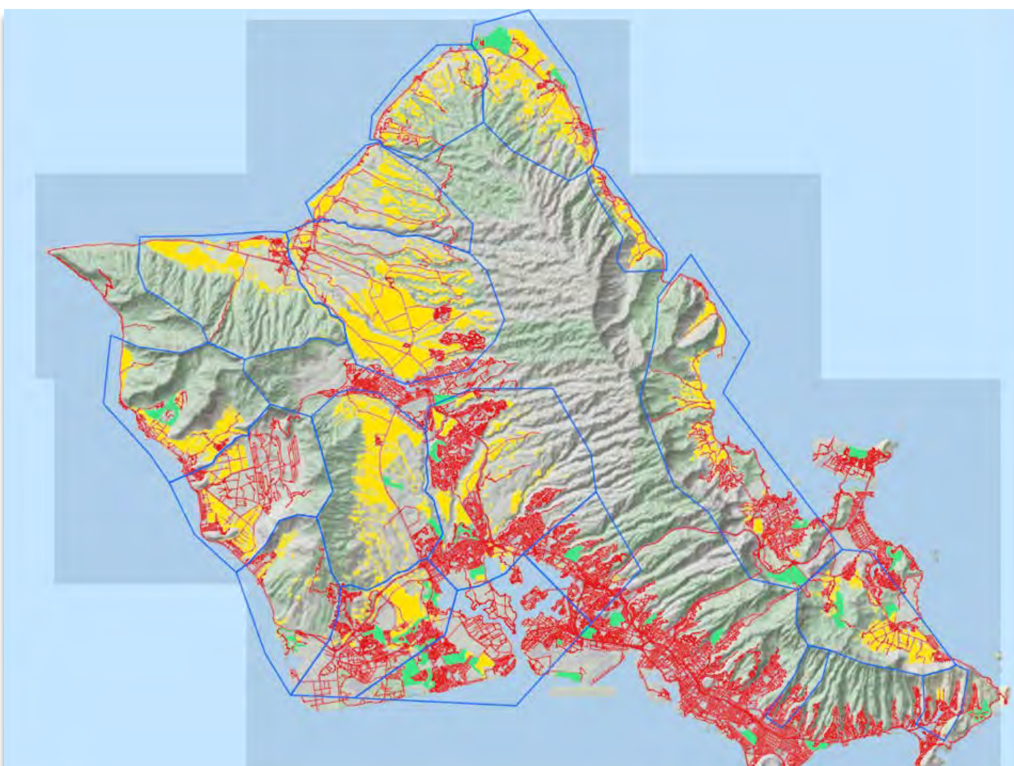
Utility-Scale Solar Resources

- only zoned for agriculture or country
  - this may exclude significant military land
- no Class A agricultural land
- no golf courses
- not within 50 meters of street centerlines
  - this also filters out rural businesses and neighborhoods
- not steeper than 10% slope
  - Waianae Solar built on slopes up to 15%
- patch is at least 60 meters across in all directions
- assume fixed PV uses 6 acres per MW(AC) and tracking PV uses 7.5 acres per MW(AC).
  - These are roughly the lower quartile of the national statistics given on p. 11 of http://www.nrel.gov/docs/fy13osti/56290.pdf
  - Waianae Solar uses 7.2 acres per MW(AC) for tracking PV systems
- assume fixed PV has a ground cover ratio of 0.68 and tracking PV has ground cover ratio of 0.45
  - these affect capacity factor when the sun is low; these values are the upper quartile from p. 13 of http://www.nrel.gov/docs/fy13osti/56290.pdf
- use NREL's PVWatts tool to calculate hourly output for each 4 km cell, using irradiance data from the National Solar Radiation Database (NSRDB)

[3]



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Rooftop Solar

- Total roof area from Google Map images
  - double-checked with visual review and comparison to population and housing data from U.S. Census
- 40% coverage of roofs, based on assuming
  - 15% of roofs are flat, with 70% coverage
  - 85% are sloped, with 35% coverage
- Estimate total capacity based on 12% efficiency with 1,000 W/m^2 irradiance (capacity=120 W/m^2)
- Hourly behavior can be modeled based on existing solar, or using NSRDB and PVWatts, with more assumptions about roof orientation

[5]

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Rooftop Solar

[6]

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Onshore Wind

- only zoned for agriculture or country
  - also not within 300 meters of other zones
- not steeper than 20% slope
  - also not within 30 meters of steep slopes (eliminates narrow ridgetops and valleys)
- density of 8.8 MW per km^2 (spacing approx. 6x6 turbine diameters)
  - less dense than Kahuku wind farm (12.9 MW/km^2)
  - on high end of the 5-8 MW/km^2 range given by an NREL report at http://www.nrel.gov/docs/fy09osti/45834.pdf
- no advance screens for resource quality
  - let the optimization model decide what is cost-effective
- turbines are clustered by region and resource quality
- hourly behavior of each project is calculated from OWITS data

[7]

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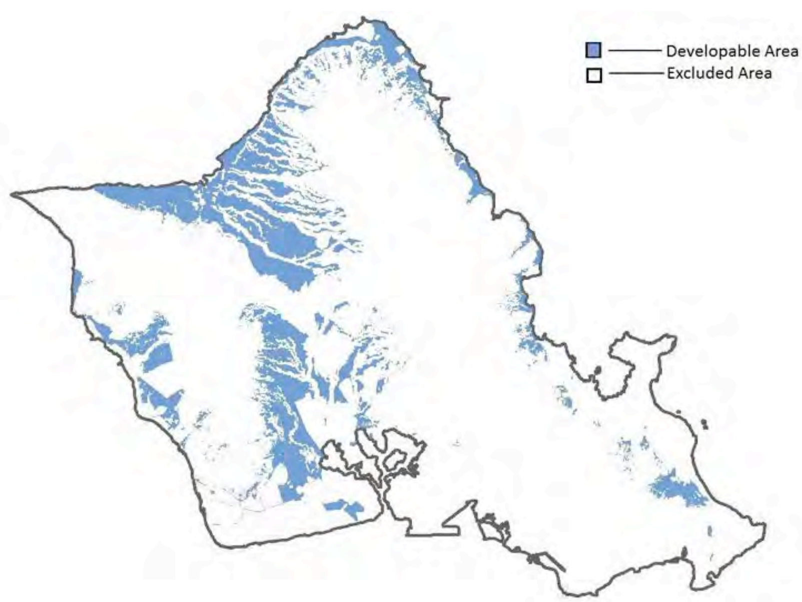
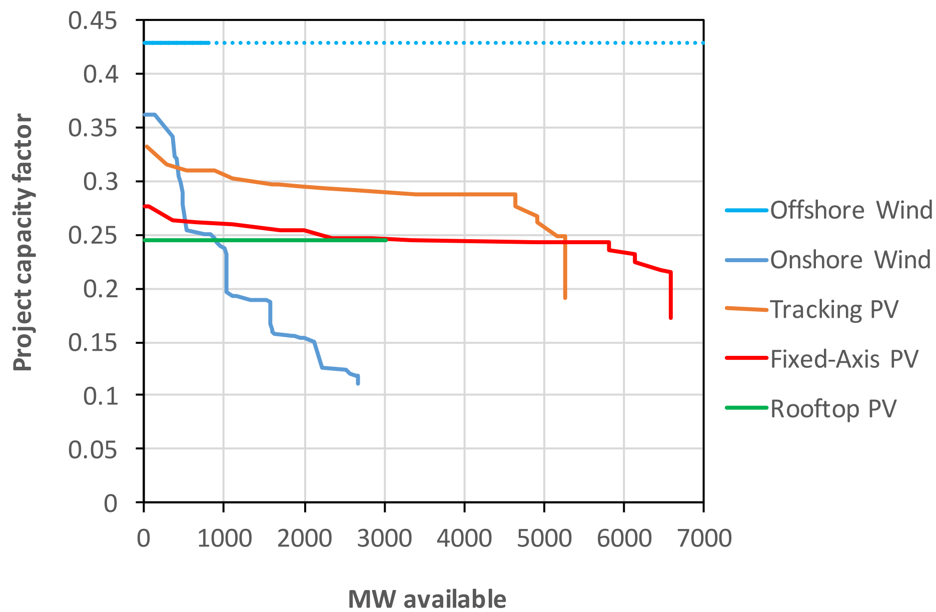
Potential Wind Farm Locations



[8]

Oahu Renewable Resource Supply Curves



[9]

Tracking Solar Should be Included

- produces 18% more than fixed-axis solar
- produces more morning and evening power than fixed-axis
- costs ~10.7% more than fixed-axis solar
  - avg. ratio for 2010-15 from p. 40 of https://emp.lbl.gov/sites/all/files/lbnl-188238_2.pdf
  - could be lower, e.g., IdeemaTec safeTrack Horizon costs $0.15-0.25/W for the entire rack and tracking system, replacing similarly-priced fixed-axis rack
- requires 25% more land than fixed-axis solar
- note: you can't use land simultaneously for tracking and non-tracking solar

[10]

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Renewable Time Series

- Renewable energy time series should be
  - site specific
    - reflects spatial diversification
    - reflects mix of resource qualities that are available
  - synchronized with loads
    - reflects correlation/anticorrelation between wind, solar and loads
- Suitable data are available from the SWITCH-Hawaii dataset

[11]

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OTHER NOTES

[12]

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Solid Biomass

- should be considered as a fuel for AES, Kahe and Waiau
- can provide extra energy on low-wind, low-sun days (plants may run all day during certain times of year)
- much cheaper than biodiesel
- pellet biomass available from Zilkha at ~$14/MMBtu
  - lower than LSFO or LNG
  - See "Public comment" [letter from Zilkha], PUC docket 2014-0183, 10/6/14, 4 pgs; http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A14J07B00959H7225418+A14J07B45304A025041+14+1960
- may be available locally

[13]

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Biofuel Limits

- There should be scenarios with and without limits on use of biomass and biofuel
  - biofuels have undesirable environmental and land-use impacts
  - biofuels may continue import-dependence and exposure to price volatility
- I recommend a limit around 5%
  - the right limit depends on policy preferences and price uncertainty

[14]

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Hydrogen Option Should be Included

- Can provide inter-seasonal storage for low-sun, low-wind days
- Important alternative to biofuels or overbuild-and-curtail
  - cost-competitive
  - reduces environmental impacts and land requirements
  - especially important in low-biofuel cases
- Simplified model available in SWITCH-Hawaii
  - Produce hydrogen and then either use it the same day or liquefy it
  - Storage tank capacity is equal to total amount of hydrogen liquefied during the year (conservative; allows any usage pattern)

[15]

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Hydrogen Cost and Performance Data Sources

- electrolyzer
  - http://www.hydrogen.energy.gov/h2a_prod_studies.html
- liquifier and tank
  - http://www.nrel.gov/docs/fy99osti/25106.pdf
- fuel cell
  - http://www.nrel.gov/docs/fy10osti/46719.pdf
- Values based on current technology are available from SWITCH-Hawaii dataset (next page)
  - also recommend considering future technology/prices

[16]

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Cost and Performance Data for Current Hydrogen Technologies

- hydrogen_liquifier_variable_cost_per_kg := 0.0
- hydrogen_liquifier_fixed_cost_per_kg_hour_year := 0.0
- hydrogen_electrolyzer_kg_per_mwh := 18.4
- hydrogen_liquifier_capital_cost_per_kg_per_hour := 41949
- hydrogen_electrolyzer_variable_cost_per_kg := 0.0
- hydrogen_electrolyzer_capital_cost_per_mw := 1557850
- hydrogen_fuel_cell_mwh_per_kg := 0.0176976
- liquid_hydrogen_tank_life_years := 40
- hydrogen_electrolyzer_life_years := 40
- liquid_hydrogen_tank_capital_cost_per_kg := 29.50
- hydrogen_fuel_cell_capital_cost_per_mw := 966402
- hydrogen_liquifier_mwh_per_kg := 0.01
- hydrogen_electrolyzer_fixed_cost_per_mw_year := 76842
- hydrogen_liquifier_life_years := 30
- hydrogen_fuel_cell_fixed_cost_per_mw_year := 32095
- hydrogen_fuel_cell_variable_cost_per_mwh := 0.0
- hydrogen_fuel_cell_life_years := 15

[17]

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Fuel Price Forecasts

- Current PSIP oil and biodiesel price forecasts seem to be consistent with historical relationship between Brent Crude and Hawaii prices
- Risk adder or Monte Carlo treatment should be applied to benchmarks (Brent Crude and Henry Hub) and then propagated from there to the forecasts for individual fuels
- Constant components of fossil fuel price formulas should probably include inflation
  - PSIP currently seems to use constant-nominal-dollar adders for delivery cost, which may understate future costs
  - e.g., if
    diesel = 1.1331×[Brent Crude ($/MMBtu)] + 1.92,
    the $1.92 may need to be inflated over time

[18]

C. Analytical Methods and Models

Planning for electric power systems utilizing 100% renewable energy is a complex undertaking. The Companies have developed comprehensive methods and modeling tools to tackle this challenge.

This appendix describes the basis of our planning, the revised optimization process, and the full capabilities of all models. Chapter 3: Analytical Approach describes the revised and refined analytical process for this December 2016 PSIP, and details how we employed this process to develop our near-term action plans.

PLANNING REQUIREMENTS AND PRINCIPLES

Our planning process incorporated various planning requirements and principles into our modeling analysis.

Planning Requirements

Planning requirements are fixed parameters that do not vary between cases or sensitivities. Planning requirements include RPS mandates, other regulatory compliance, planning criteria, and enabling customers the choice of providing cost-effective and reliable grid services.

RPS Mandates. Hawai‘i state law mandates that each operating utility must meet the RPS "renewable electrical energy" sales requirements over the next 30 years, ultimately attaining 100% RPS by 2045.

Regulatory and Environmental Compliance. Plans must comply with various state and federal laws and regulations, including applicable environmental laws and regulations.

Planning Criteria (including system security requirements). Planning criteria are standards for safe, reliable power supply for customers. Planning criteria are developed considering system security requirements, system reliability, loss of load probability, service quality, and adequacy of supply necessary to maintain an acceptable level of reliability.

System security is the ability of an electric power system to regain a state of operating equilibrium and maintain acceptable reliability when subjected to possible events. These events—or contingencies—include loss of generation or electrical faults that can cause sudden changes to frequency, voltage, and current. Operating equilibrium must be restored to prevent damage to utility and end-use equipment, to ensure public safety, and to keep the power on.

System security requirements are necessary to provide an adequate level of reliability. Currently, generators provide the majority of the necessary system security attributes. At some point, DR and energy storage resources might be available in sufficient capacities to augment or replace these generators. Updated system security analyses identified primary and fast frequency response requirements for each island system. Continued analysis based on planning criteria might identify additional resource needs and operational constraints.

Enabling Customers with Cost-Effective Choices. With more DER options, customers have choices that we will continue to enable. Customers can effectively consume energy, use our electricity services, and provide services back to us. Customers also have the choice to provide grid services to the electric system; the price for such grid services, however, must reflect their economic value relative to other resources.

Planning Objectives

Planning objectives are the specific results the planning process aims to achieve. Planning objectives of the PSIP are consistent with Commission directives: to advance achievement of the State's 100% renewable energy goal, to stabilize and reduce customer rates, and to maintain safe and reliable service.

Achieve the State's 100% Renewable Energy Goal. Our objective is to achieve 100% renewable energy by or before 2045 to comply with Hawai'i state law. We strive to exceed the interim RPS targets integrating additional renewable energy that can help reduce customer rates.

Stabilize and Reduce Customer Rates. Stabilizing and reducing customer rates is a primary objective of the planning process. The analysis methodologies utilized in the December 2016 updated PSIP are designed to minimize total system costs. Total system costs consider the total costs to the electric system, including generation, transmission and distribution, interconnection, revenue requirements, capital expenditures, and integration costs. Mitigating customer and implementation risk are factors to stabilizing and reducing customer rates.

Maintain Safe and Reliable Service. Safe and reliable service is the foundational element of our electric power grid. An integrated, robust plan for first avoiding, then handling contingencies is necessary, and an increasingly difficult task as more and more variable renewable generation is added to the system.

OPTIMIZED ANALYTICAL PROCESS

Our planning engineers, working closely with consultants, developed an innovative and transparent process to optimize all resources including DER, DR, and grid-scale resources, and build on our DR work completed to date. This iterative process builds on the process employed in our April 2016 PSIP update, and incorporates all of the updated input assumptions. Figure C-1 depicts the flow of the modeling tools and the optimization of DER, DR, and grid-scale renewables.

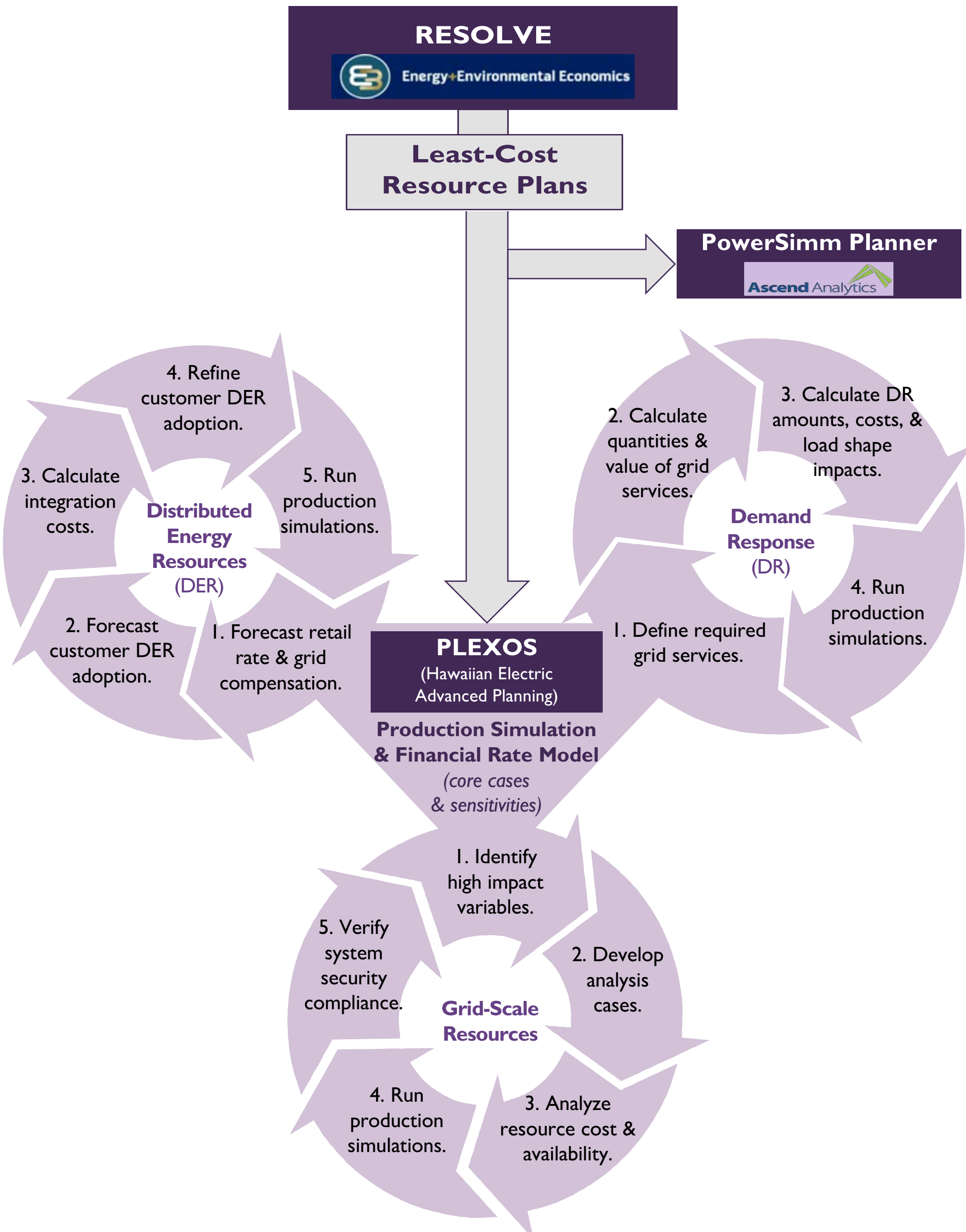

Figure C-1. Revised PSIP Optimization Process

The following sections explain the DER, DR, and Grid-Scale Resources iterative cycles.

Distributed Energy Resources Iterative Cycles

DER includes assets such as DG-PV and distributed energy storage systems (DESS) that play a critical and growing role in the future electric system. Customers decide to install these assets based on a number of factors, including cost savings on electricity consumption and compensation from providing grid services through DR programs. We plan to integrate and optimize DER into the generation resource mix on a system level based on customer decisions to install these assets.

To begin, we forecast the potential DER that customers would be willing to adopt based on preliminary assumptions on customer economics related to DER. We developed forecasts for market DG-PV (based on expected customer response to market pricing) and high DG-PV (all single-family residential customers and 20–25% of total commercial customers are net zero). We assume that existing DER programs, including legacy NEM, Standard Interconnection Agreement (SIA), Customer Grid Supply to cap, and Customer Self Supply run through their current program life at current compensation levels. In addition, we assume a new program for grid export of DG-PV will be instituted—similar to today's Grid Supply program but with an updated compensation rate—for planning purposes only.

Forecasting assumptions include historical hourly customer load profiles by island and rate schedule from the Company's class load studies, optimum system size, tariffs, export rate, retail electricity prices, storage value, income tax credits, system costs, eligible customers, inflation rate, and weighted average cost of capital.

We have refined these economic adoption assumptions, and developed models to forecast adoption rate.

1. Forecast Retail Rate and Grid Compensation

The payback time of a customer-sited DER system is determined by customer benefits received over time versus customer cost for the DER system.[1] The DER system can benefit customers by offsetting their retail electricity purchases with compensation for providing grid services.

Forecast Payback Time for DG-PV Compensation. Order No. 33258[2] specified the compensation rate and cap by island for a new grid-supply product. As a preliminary assumption for the compensation of the export of future DG-PV not covered under the existing programs and aligned with a Planning Objective to achieve lowest cost, we:

- Considered resources with similar variable generation attributes, to avoid inequitable comparisons to firm generation resources.
- Considered resources with comparable time-of-day production (for example, those resources producing during solar generation hours).

[1] Appendix J: Modeling Assumptions Data contains forecasts for the cost of DG-PV, grid-scale PV, and residential energy storage. These cost forecasts were developed in conjunction with the grid-scale cost assumptions utilizing the same base data sources and assumptions.

[2] Issued on October 13, 2015 in Docket No. 2014-0192: Proceeding to Investigate Distributed Energy Resource Policies.

- Enabled full utilization of DG-PV. To achieve an objective at lowest cost, this implies compensating DG-PV at the same level as alternative energy resources with similar attributes (renewable, variable, producing during solar generation hours).
- Modeled the DG-PV resource as controllable and curtailable, similar to other variable generation resources.

We compared grid-scale PV with DG-PV. We also assumed the future DG-PV export rate to mirror the respective levelized cost of energy (LCOE) of grid-scale PV for every year of the 30-year planning horizon. This assumption ensures optimal amounts of DG-PV are fully utilized by the system under economic dispatch principles. (This is simply a modeling assumption, and not a policy decision.) Continued analysis could further refine these assumptions.

Forecast Payback Time for Other DER Compensation. Retail electricity price and the value of grid services are a function of the overall electric system. Retail electricity price forecasts are derived from the production simulation and financial rate model. The value of grid services is derived from the production simulation and DR modeling.

Forecast Payback Time for Cost Forecasts. DER technology capital cost and operations and maintenance (O&M) cost forecasts are included. Payback time is forecasted based on the revenues and costs.

DER Controllability. This updated PSIP assumes system operator control of DG-PV will be feasible before or by mid-2018, based upon the following:

- Commission approval of our proposals in the DR docket by the end of 2016 and of our proposals in the DER docket by the end of 2017.
- A Distributed Energy Resource Management System (DERMS) implemented by mid-2017. A DERMS incorporates traditional Demand Response Management System (DRMS) functionality and a full suite of distributed energy management capabilities currently in production and under development by Omnetric. The DERMS is assumed to control a wide array of distributed energy resources, regardless as to whether they are enrolled specifically in a DR program.
- This updated PSIP assume policies and programs (including pricing programs) that stipulate DER control by 2019. The details of these policies and programs are expected to be captured outside of the updated PSIP and jointly between current DR program filings and the anticipated DER Phase II proceedings.
- Ability to exercise DER control. Our AMI infrastructure is not currently expected to be implemented until after 2018. We expect that aggregators and DER providers will install near-term communications sufficient for the preliminary stage of DER control and the associated feedback loop.

2. Forecast Customer DER Adoption Levels

If the customer's payback time on their initial investment is short, more customers will adopt DER; if payback time is long, fewer customers will adopt DER. An initial forecast of customer adoption of future DER is calculated based on the historical correlation between payback time and adoption of DG-PV and on the forecasted payback time of DER systems.

3. Calculate Integration Costs and Curtailment Amounts

When DG-PV installations exceed the circuit hosting capacity limit, circuit upgrades are required while some curtailment might also be required. Integration costs and curtailment amounts to accommodate DG-PV over the circuit hosting capacity limit are calculated by circuit.

We developed a methodology to quantify integration costs on circuits over the hosting capacity. That methodology allocates DG-PV forecast pro-rata across circuits, identifies integration solutions and their respective costs, then applies these integration costs to adjust the economics and the expected adoption rate from both a system and a customer perspective. Integrating variable renewable energy (including DG-PV, grid-scale PV, and grid-scale wind) might require regulating reserves, energy storage, and investments in system operations. Based on these changed economics, the DG-PV is reforecast.

Figure C-2 depicts a high-level overview of the circuit-level integration cost methodology.

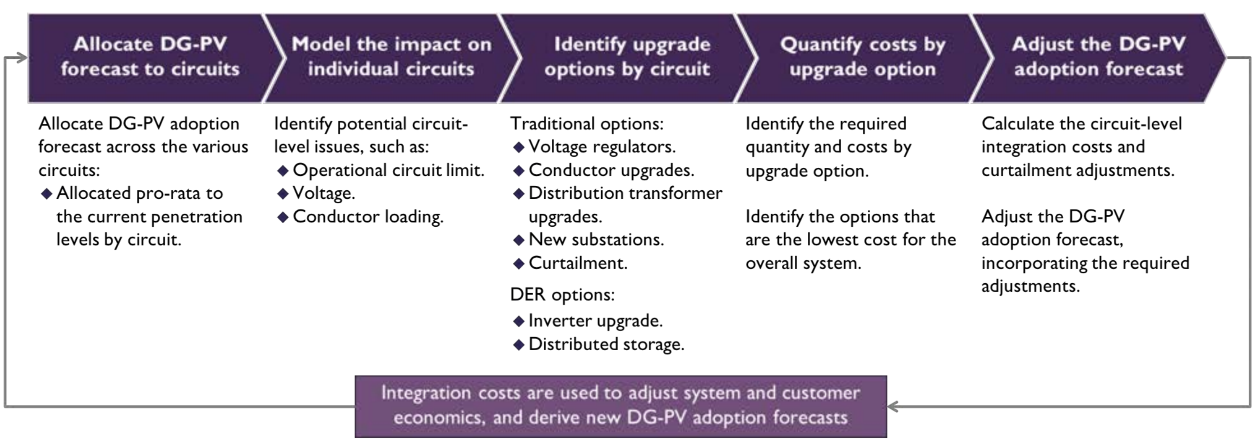

Figure C-2. Circuit-Level Integration Cost Methodology

4. Refine Customer DER Adoption Levels

Integration costs adversely impact the value of DG-PV for customers adopting DG-PV above the circuit or system hosting capacity limits. As a result, integration costs can result in a refined payback time and associated customer adoption rates. To determine preliminary assumptions for our 2016 PSIP analysis, integration costs are allocated only to those customers who install a DG-PV system above circuit and system hosting capacity limits (and not assumed for other customers), or integration costs are allocated to all customers. DG-PV adoption forecasts and costs to customer are provided for each instance.

We continue to refine the economic adoption assumptions and are developing programs to enhance this adoption rate. These programs optimize and provide the most benefits for our customers and grid services in conjunction with other renewable resources in our future portfolio.

5. Run Production Simulation with DER Adoption Levels

The previous four steps result in a forecast of DER adoption levels based on two factors: one, customer uptake of DER based on the economics from the customer's perspective, and two, provision of power supply and grid services from the customer that is cost effective for the overall system.

These DER adoption levels are then included in a subsequent production simulation and financial model iterations and as potential in the DR iterative cycles. The DER adoption levels impact net sales and peak forecasts. If the retail electricity price and the value of DER substantially change in the production simulation and financial model, and in the DR modeling, then the five DER steps are iterated again. Successive iterations optimize the quantities of DER.

Demand Response (DR) Iterative Cycles

Demand Response requires a separate iterative cycle for resource planning.

The DR evaluation was conducted using the post-April 2016 PSIP plan for each island, and the results were used in the production simulation and capacity planning models for the December 2016 PSIP update evaluation period. Grid service valuation was initially performed on a single plan per island; this guided the evaluation of DR amounts, costs, and the impact of system load shapes. Those initial plans per island were:

- *O'ahu, Hawai'i Island, and Maui:* Renewables without LNG
- *Lana'i and Moloka'i:* 100% renewable energy achieved in 2030

DR amounts, costs, and the impact on system load shapes were then evaluated on all post-April PSIP plans. In addition to those listed above, this included:

O'ahu and Maui:

- Accelerated renewables without LNG
- Renewables without LNG and without new generation
- Renewables with LNG

Hawai'i Island:

- Accelerated renewables without LNG
- Renewables with LNG

Later analyses involving both grid services valuing as well as defining DR amounts, costs, and the impact on system load shape are to be performed on the E3 plan:

- *O'ahu:* E3 Plan and E3 Plan with generation modernization
- *Hawai'i Island and Maui:* E3 Plan

Results of grid services valuing, updated for any differences developed following the post-April PSIP plan evaluations, will be documented in the February 10, 2017 DR Application.

1. Define Required Grid Services

Our portfolio of DR programs delivers grid services that help meet system security and other requirements that displace the need for resources. These grid services serve as the basis of all programs. Grid service definitions are cross-referenced with DR program attributes and rules to ensure an effective delivery of the grid services by DR resources. As part of the December 2016 PSIP update, some of the service definitions and their associated requirements were modified, although more will be addressed in the DR Application Tariff, Rules, and Rider modifications.

The first step in DR optimization is to assess the degree to which these modifications impact the DR potential, and thus the overall DR portfolio. In parallel, we are adjusting, as necessary, the market potential of the various DR programs.

The DR potential study model is re-run with these modified and refined inputs: updated forecasts for EVs and storage based on new fuel and resource forecasts and modified assumptions; load forecasts based on new resource plans; adjusted ability to control a DR resource based on revised program attributes; refined end-use load shapes and associated ability to shed load; and modified percentage of customers willing to enroll in a particular program.

2. Calculate Quantities and the Value of Grid Services

To identify the potential for DR resources to deliver grid services, DR optimization must first understand the quantities and value of the various grid services for each time interval, for each island power grid. To the extent feasible, DR opportunities for providing each grid service is evaluated independent from each other based on the results of Step 1 of this DR optimization.

Costs will not always be aligned with quantity. For example, without DR, a firm unit may be required to remain online during the mid-day solar peak in order to provide regulating reserve. With some portion of the regulating reserve requirement provided by DR, the unit may be shut down during the mid-day solar peak. This may require a startup to meet the evening demand. While DR results in a lower daily cost, the unit startup will result in an hour with higher cost.

The value of a given grid service might depend on that grid service being provided concurrently and in conjunction with other grid services. For example, the contingency reserve service may be linked to the primary frequency response (governor response) combined with the regulating reserve to alleviate a must-run requirement. This means that a DR resource that provides only a single grid service would have limited value on a stand-alone basis. A DR portfolio that provide multiple services will have greater value.

The value of each grid service is calculated to determine how they are best to applied to all potential grid-scale resources. Grid service values are calculated by comparing system production costs between model runs for adjusted service levels. More precisely, augmenting the system with a free resource that can provide the specific grid service results in differences in system costs that can be used to calculate the incremental costs of delivering that service. Understanding the relationship to quantity and value of services over time helps determine substitution opportunities for all resources. Generators can be simulated as must-runs for reliability. If a service can meet the reliability need, the must-run requirements can be adjusted to allow generation to be dispatched economically. The change in costs from relaxing must-run constraints helps infer the value of a service (such as inertia).

3. Calculate DR Amounts, Costs, and System Load Shape Impacts

Once the quantities and values of grid services have been derived, an optimal DR portfolio is developed. An iterative process derives both the population of end-use devices and the resulting DR fit for delivering grid services cost-effectively. Several sub-tasks comprise this iterative process.

Preliminary Inputs. These inputs are required for analyzing DR fit:

- The refined DR potential calculated during DR optimization Step 1.
- The quantity and value of the services derived from DR optimization Step 2.

Identify DR Portfolio Fit. DR can provide a portion of the required grid services by displacing grid services otherwise provided by generating assets within an analysis case. The projected fit and value of DR products to meet some or all of each of the grid service needs, for each time step, is determined for each island power grid. Using the Adaptive Planning model (developed by Black & Veatch), the provision of grid services from conventional resources and DR products are optimized to meet the power system reliability requirements at minimal overall cost (producing cost savings). Cost savings result from changes in the timing of the expansion plan or size of an added resource, changes in the timing of deactivation, or changes in operation. These cost savings can be capital deferment, avoided fixed costs, or avoided variable costs.

DR programs can be reshaped daily to address changes in demand, wind and solar profiles, and the availability of assets.

The Adaptive Planning model can then calculate the "stack" of DR resource utilization and allocate them to maximize their value to the DR portfolio. This capability allows us to assess the fit of the model's results against system security needs and the underlying asset portfolio characteristics.

A sensitivity analysis is then conducted to expose areas where changes in the electric system can substantially impact the value of DR. These sensitivities include changes such as the availability, size, and cost of storage and the role of DR products given modified security constraints.[3]

Derive Value Associated with Customer Storage. Customer owned storage can provide value to the grid system – and can provide additional value as the utility influences the timing of use of the customer storage. The Adaptive Planning model develops annual values ($/kw of installed customer storage) associated with bundles of grid services that can be delivered by a stand-alone storage device. This then serves as a proxy for the annual economic value earned with stand-alone DESS. This value is calculated and provided to inform customer storage adoption models that predict the build-out of DG-PV plus energy storage systems and storage only systems.

Forecast Customer Adoption. The value that a standalone DESS or DG-PV plus storage system provides by participating in a DR program is included as a revenue stream in calculating customer payback and the associated adoption of these two types of storage systems.

Refine Populations and Potential. Forecasted customer adoption for DESS and DG-PV plus storage is provided to the potential study model. A revised DR potential is then calculated based on the updated customer groups.

Rerun DR Portfolio Fit. This revised DR portfolio potential is then used to determine the DR fit and corresponding value of the DR programs. The DESS and DG-PV plus storage values are compared to the values previously calculated. If these values are essentially consistent with the previous iteration, forecasting is complete because the convergence reflects an optimal population of the end uses and the DR portfolio as a

[3] The adaptive cost model can employ revised system security requirements to evaluate their impact on the opportunity for DR to deliver grid services, but the model cannot evaluate the security viability of these modifications. While they may present additional cost avoidance opportunities, they may also introduce additional system risk.

whole, for that particular case—in other words, the best fit. If the values are meaningfully different, then customer adoption is re-forecasted.

Iterate until Values Converge. If the economic value of DR, DESS, and PV plus storage converge, the iterative process is complete because the economic value of the populations and the DR portfolio are sufficiently optimized for that particular case. If these economic values vary, iterations continue until the set of economic values converge.

Finalize the DR Portfolio. A DR portfolio is optimized when the fit and economic values converge. This optimized DR portfolio is then finalized and used in production simulations. For each case, these results are a combination of the:

- Effective impact on the system load shape by hour by year for the entire planning period. As DR is intended to manipulate demand to deliver grid services, an optimized portfolio ultimately impacts system load shapes.
- Ability of the DR portfolio to provide regulating reserve, by hour by year for the entire planning period. The regulating reserve profile ensures that DR information is available so that DR can substitute for firm generation in meeting regulating reserve requirements.
- Contribution of DR portfolio towards meeting Fast Frequency Reserve requirements.
- Avoided annual costs of the portfolio for the planning period.
- Material adjustments made to the resource plans resulting from the DR optimization. Changes include resizing resources, shifting retirement schedules, deferring capital investments, and shifts in procurement timing.

4. Run production simulations and economic evaluations with DR adjustments

The optimized DR portfolio is then used as an input to the production simulation model. Portfolio costs and any cost impacts related to resource plan adjustments are added to the economic evaluation of each resource plan case.

Grid-Scale Resources Iterative Cycles

The grid-scale resource iterative cycle is similar to those for DER and DR.

1. Identify High Impact Variables

Variables that have a high impact on the Planning Objectives are first identified. Initial examples include fuel type, extent of generation modernization, and amount of DER adoption. In subsequent iterations, additional high impact variables are identified and varied between cases to understand their impact on the Planning Objectives.

2. Develop and Refine Analysis Cases

Cases to be analyzed are developed based on the high impact variables and the results of the DER and DR iterative cycles to better understand their impact on the Planning Objectives. For example, the fuel type used in one case might assume a low LNG price forecast whereas another case might assume a low oil price forecast (without LNG) as a transition fuel toward attaining the 100% RPS goal.

DR amounts, costs, and system load shape impacts from the DR iterative cycles are also incorporated into the cases run in the production simulation.

3. Analyze Forecasted Resource Costs and Availability

This step determines near-optimal resource quantity and timing. The production simulation and financial rate model determines, at a very detailed level, generation output and the associated rate impacts for a given case. Multiple cases are compared, revised, and successively iterated until a plan is identified that best meets the Planning Objectives.

To make this iterative process more efficient, resource cost forecasts are analyzed outside of the production simulation to identify likely near-optimal resource quantity and timing for the various analysis cases. Two models outside of the production simulation identify likely near-optimal resource quantity and timing.

Resource Cost Competitiveness and Economic Curtailment Amount. This model identifies how much of a new resource can remain cost effective when curtailed, and when such a resource should be introduced into the plan. The model calculates when a new resource costs less than an existing resource, and how much can be curtailed while still remaining less costly.

System Need and Cost-Effective New Resource Implementation Amount. This model, accounting for system needs and economic curtailment, determines how much of a new resource can be added to the system by calculating the net non-curtailable resources from load. The model then adds the cost-effective resources up to the economic curtailment amount to determine the annual amount (in MWs) that the new resource can be added.

The two models output an annual schedule as to when a new resource can cost-effectively be implemented, and when existing resources can be retired. This schedule is then used in the production simulations.

4. Run Production Simulations

This step analyzes cases to test the incorporated high impact variables and near-optimal resource quantity and timing. Production simulations calculate each resource's generation through hourly and sub-hourly unit commitment and economic dispatch algorithms. Outputs are then used to determine the total system costs and the impact on customer rates that consider capital costs, fuel costs, and fixed and variable O&M costs over the planning period. These results are analyzed, and then iterated until a plan is unveiled that best meets the Planning Objectives.

5. Verify System Security Compliance

Each case is analyzed to ensure it meets system security requirements for simulated commitment schedules and dispatch levels when subjected to various contingency conditions. If system security requirements are not met, technology-neutral system requirements are determined and adjustments made to the resource plans. Sometimes, generating units must be committed or dispatched outside of ideal economic dispatch levels until technology-neutral alternatives are added to the grid or until the driving contingency event can be eliminated to maintain system security.

When sufficient capacities of DER and DR resources are available, ancillary services provided by thermal units will not constrain resource plans.

ANALYTICAL MODELS

We are employing a number of analytical models to develop our December 2016 PSIP. Our Advanced Planning team, our Transmission and Distribution Planning team, Forecasting team, Demand Response team, Finance team, and several consultants process numerous individual and overlapping model runs using these tools. Together, we are performing a thorough, exhaustive analysis to develop a series of alternative plans. Then, from those plans, we are developing the near-term action plan for each operating utility to provide reasonable cost, reliable energy to our customers while reaching our 100% RPS goal.

These modeling tools and the team running the tool include:

- *RESOLVE Optimization Model and Long-Term Case Development*: Energy and Environmental Economics (E3)
- *PowerSimm Planner*: Ascend Analytics
- *PLEXOS® for Power Systems*: Hawaiian Electric Advanced Planning Department
- *Adaptive Planning for Production Simulation*: Black and Veatch
- *DG-PV Adoption Model*: Hawaiian Electric Forecasting Division
- *Customer Energy Storage System Adoption Model*: Hawaiian Electric Demand Response Department
- *PSS®E for System Security Analysis*: Hawaiian Electric Transmission and Distribution Planning Department
- *Financial Forecast and Rate Impact Model*: Hawaiian Electric Budgets and Financial Analysis Department

How Models Were Run for Our Analysis

No single model has the ability to produce completely optimized plans incorporating DR, DER, grid-scale resources, and system security resources. Instead, we utilized a number of models to conduct the analysis necessary for developing our December 2016 PSIP. These models were RESOLVE, PowerSimm Planner, PLEXOS for Power Systems, Adaptive Planning for Production Simulation, DG-PV Adoption, Customer Energy Storage System Adoption, PSS/E for System Security analysis, and the Financial Forecast and Rate Impact Model.

An explanation of each model follows: how it was used in our analysis, its inputs and outputs, and its limitations.

To support the PSIP, historical data and econometric models predict DR together with DG-PV and energy storage (DER) adoption; RESOLVE drives optimal asset portfolio design; PowerSimm Planner supports the analysis with stochastic modeling to account for risk and to validate results; Adaptive Planning for Production Simulation optimizes the use of DR and DER; PLEXOS provides detailed production simulation and cost data for the generation system; PSS/E examines system security requirements; and financial rate models determine the ultimate cost to the customer.

RESOLVE Optimization Model

E3 assessed long-term plans for O‘ahu, Hawai‘i Island, and Maui by running the RESOLVE optimization model on the core cases and on many sensitivities.

The E3 analysis determined what set of incremental system capacity investments and dispatch decisions for each island would be least cost to meet their RPS goals under the assumptions defined for the core cases and sensitivity cases.

The E3 analysis focused on developing theoretical, least-cost resource plans to achieve the RPS goals and investigating the impact of large scale decisions (such as LNG, the interisland cable, and other sensitivities), and how they might influence near-term actions. The result is a quantitative evaluation of available resources and sensitivities to determine least-regrets near-term actions.

Input Assumptions and How They Are Used in RESOLVE

E3 ran RESOLVE, an optimal capacity expansion model which considers the total cost of new resources being built on the system, to conduct its analysis. RESOLVE minimizes total costs over the planning period (out to 2045) where years in the future are being discounted at the utility cost of capital. Important inputs include sales and peak forecasts, load shape and flexible loads, hourly renewable resource shapes, resource performance characteristics, and new and existing resource costs.

Load shape and flexible loads. RESOLVE took as input the Hawaiian Electric hourly load forecast out to 2045, which includes the effects of efficiency and vehicles, but is not net of DG-PV. RESOLVE also takes an hourly flexible load potential (provided by Black & Veatch). This flexible load potential is combined with the Hawaiian Electric load forecast to create two hourly forecasts: 1. a “base” case forecast, which is the unmovable portion of load that must be met in each hour, and 2. a flexible load that can be shifted during the course of the day, provided it follows the constraints of the hourly flexible load potential given by the Black & Veatch hourly forecast. Flexible load energy over the sum of the day is the same—that is, flexible loads are assumed to have a net zero impact on total energy. Thus, over the course of the day, the “base” plus “flexible” loads must have the same amount of energy as the Hawaiian Electric hourly load forecast. In this way, we aim to capture increased DR and other programs that allow for more flexible, demand-side load management.

Hourly renewable resource shapes. These resource shapes include DG-PV, grid-scale solar PV, onshore wind, and offshore wind. The model combines the hourly resource unitized shape with the capacity of that resource to create an hourly energy created by each renewable resource. Some of these resources are curtailable, and some are not (that is, all DG-PV online before 2020 is uncurtailable). Resources that are curtailable can also offer upward and downward reserves.

New resource and existing resource costs. Hawaiian Electric provided levelized capital costs for new units on a $/kW year basis. The RESOLVE model allows each island to buy the relevant new resources at their levelized costs. For example, if RESOLVE decides to buy a 10 MW wind plant in 2020, the cost for that plant will be 10 MW times the $/kW year for 2020; the levelized capital cost is valid throughout the lifetime of the plant. This levelized capital cost includes any fixed O&M cost as well as interconnection costs that the facilities are charged. Similarly, existing generation resources have an annual fixed O&M cost. Both existing and new resources must pay the variable O&M costs and fuel costs which stem from every MWh of energy produced. (This is relevant only for thermal resources, as renewable sources such as solar and wind do not have a variable O&M cost.)

The resulting plans from RESOLVE were evaluated by Hawaiian Electric using the hourly production simulation model PLEXOS. Our Advanced Planning team integrates DER and DR in that process. The results are used in the financial analysis and the plans are evaluated for system security.

RESOLVE Model Limitations

The nature of the capacity expansion modeling means RESOLVE has some limitations.

To ensure reasonable model solve time, RESOLVE represents a year using a representative sample of weighted days. The subset of days is selected to cover the full range of potential conditions encountered over the provided 8,760-hour shape that would influence the planning decisions in the future. Days are weighted to reflect the long-run distributions of key metrics including hourly load, hourly renewables for each island (including solar, onshore wind, and offshore wind and hydroelectric when appropriate), and hourly net load. Instead of simulating every single year, we model 2020, 2022 (the LNG decision year), 2025, and every fifth year afterwards.

The model ensures that reserve requirements are held in both upwards and downwards directions. These reserves account for contingencies and increased variability over an hour from renewables, but do not include the short-term reserves over short timeframes. This is particularly important in later years of the model when thermal generation providing system inertia is potentially taken offline. Other resources are left for short-term system balancing. Currently our reserve requirements and generator characteristics do not ensure this capability is met.

Planning Reserve Margin Methodology Used in RESOLVE

E3 used a reserve margin methodology as part of their planning and modeling to create their resultant plans.

Planning reserve margin (PRM) is designed to ensure that enough dependable generation capacity is available to meet expected demand in the planning horizon. It is defined as the differences between the resources available and the expected peak period loads. Under conventional conditions, a system planner can calculate expected peak load and ensure there are enough reliable dispatchable resources available to meet the expected peak load plus some margin for reserves, contingencies, planned maintenance, and unplanned events. Typically this process involves choosing a reliability standard based on an expected loss of load probability (LOLP; for example, one day in ten years), and a corresponding PRM designed to maintain that LOLP over the planning horizon in each plan. However, Some jurisdictions, however, are increasing their dependence on renewable or variable energy resources (VER) to meet their RPS requirements. For them, this simple PRM calculation based on LOLP needs to account for the specific VER's contributions to PRM at each stage in the plan.

Because VERs produce energy that is stochastic by nature, it is unreasonable to count their entire nameplate capacity in calculating the amount of resources available to meet PRM (for example, a 20 MW wind plant should not contribute 20 MW to the PRM). Conversely, completely ignoring renewable resources in the PRM calculation would result in an excessive thermal build unused for large amounts of time because of expensive fuel costs or RPS constraints. The RESOLVE methodology creates a simple metric representing the amount of capacity a planner can rely on to attribute to renewable resources in maintaining "dependable capacity".

Unlike a traditional PRM calculation (which is focused on maintaining sufficient capacity to serve the expected peak load), the PRM methodology E3 used (outlined below) is calculated for every hour in the planning horizon. While only one of these hours is binding, that binding hour cannot be identified because it is determined by an interplay of energy demand, demand response, DG-PV, and the "dependable capacity" produced for each renewable resource. For example, the binding hour for PRM in a system with only solar renewable resources will likely occur in the evening, while the binding hour for a system with a combination of wind and solar resources could occur earlier in the day.

PRM Methodology Calculation Steps

These steps describe the methodology used to value the PRM contribution of renewable resources in this planning study that incorporates the interplay described above. The process begins with normalized hourly generation shapes for each renewable resource. The normalized hourly generation shapes used in the PSIP analysis, produced by the National Renewable Energy Laboratory, are hourly forecasted generation for 2045.

1. Calculate the distribution of the hourly renewable output for each renewable resource for each season-hour (for example, summer hours 1–24).

2. Calculate the tenth percentile of each distribution above (the tenth percentile represents the energy a planner can rely on for the identified renewable resource to provide with a 90% confidence level).

3. Use the identified tenth percentile calculated for each renewable resource in each season-hour and map it to the entire year (for example, apply the tenth percentile value for summer hour 12 to the twelfth hour of all summer days in the year in question in the plan on each island).

4. For each renewable resource, multiply these hourly tenth percentile values (calculated in the previous set) by the installed nameplate capacity of the renewable resource to calculate the hourly "dependable capacity" MW contribution of that renewable resource to the PRM.

   For example, assume the tenth percentile for solar summer hour 12 was 0.10 and the system had 110 MW of nameplate solar installed. The solar contribution to PRM during each summer hour 12 would be 0.10 multiplied by 110 MW which would equal 11 MW.

5. For each hour, add together the PRM contributions from renewable resources, thermal resources, and batteries (described in "Thermal and Battery Contribution to PRM" below) to calculate the hourly PRM generation available.

6. Compare the available PRM generation with the PRM requirement, specified as a multiplier (greater than 1) of the hourly load.

7. If the generation side of the PRM constraint is greater than the load side for all hours, the PRM requirement has been met for the year in question. If there are one or more hours in which the PRM load requirement is greater than the generation resources available to meet PRM, the model must procure additional generation resources at least cost.

In this way, RESOLVE can rely on some level of renewable output for capacity instead of relying solely on an increasingly lower capacity factor thermal fleet in a high RPS world.

Thermal and Battery Contribution to PRM

Thermal resources contribute their maximum rated power output towards the PRM constraint.

In this planning study, we find that batteries are built more for energy purposes (that is, absorbing high renewable output hours and shifting the energy to lower output hours) than for providing capacity. Nevertheless, we allow batteries to contribute to PRM. A battery's contribution to the PRM constraint is the power output a battery could discharge for four hours. For example, if a battery held 4 kWh of energy, then its contribution to PRM would be 1 kW as that is the power output the battery could maintain for four hours (1 kW for each hour). This four-hour cutoff is consistent with planning methodology used in the California market, which is one of the few markets with explicit formulations for how to evaluate the planning and capacity contributions of batteries.

Suitability for Using a Simple, Single-Hour and Fixed PRM Number

This relatively simple PRM methodology is designed to determine the economic comparison of costs and benefits of a large number of cases over a relatively short period. It is largely unbiased towards different resources and is therefore suitable for comparing the costs of each PSIP plan.

Although the proposed process accounts for a VER's contribution to meeting a simple, single PRM calculation for a single hour, the approach is too simple to assure that the reliability between each PSIP plan or over the course of each PSIP plan is maintained. For this reason, the Companies have proposed using a number of other models to test the reliability of each of the studied PSIP plans. However, even that analysis is probably insufficient and limited by time, data, and analytical tools. In particular, the simple, single-hour contribution of each VER and the fixed PRM percentage over the course of the expansion plan are simplifications that need to be tested.

In California, as part of their long term planning process, E3 is currently building a version of RESOLVE that incorporates information from our RECAP model that determines the specific LOLP and PRM needed for each plan over time and the equivalent load carrying capability (ELCC) of each VER over time in each plan as a more accurate way to count VERs in their contribution to dependable capacity.[4]

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[4] A description of how RESOLVE is being adapted to incorporate a more detailed check on reliability in California can be found here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451565.

PowerSimm Planner

Ascend's PowerSimm modeling tool evaluated costs associated with renewable expansion plans. By optimizing dispatch according to unit characteristics, forecasted fuel prices, load, and renewables, the expected costs associated to each plan can be measured and accounted for. In addition, by introducing stochastic simulations into the modeling framework, PowerSimm is able to output a range of possible future costs for each portfolio. By summarizing the range of costs through a risk premium, the Companies can directly compare the merits of trading off expected costs for higher risk.

In addition to cost and risk, PowerSimm is able to measure dumped energy in every renewable expansion plan. These results determine the amount of load-shifting battery storage required, and calculate the cost of this storage. PowerSimm models the effect of adding this storage to the portfolio, so this process of measuring dump energy and calculating storage costs can be repeated. By running multiple studies for a given expansion plan with varying levels of battery storage, we are able to hone in on a level of battery storage that strikes the right balance between minimizing costs and minimizing dump energy.

System Flexibility Software, a module of PowerSimm Planner, has the ability to estimate one-hour ramps and regulation for a variety of fixed scenarios for daytime and nighttime requirements. PowerSimm's System Flexibility Software runs a large number of scenarios scaling historical minutely data to forecasted load wind and solar capacities. The regulation tool enables interactive queries into the output of these runs. The queries enable a choice of a base or high DG-PV forecast, the year, solar adders for capacity to utility solar baseline forecasts, and wind adders, similar to solar adders. Regulation and ramp statistics are also shown for the strategic and aggressive strategies for the selected year, and are partitioned by daytime and nighttime. Graphs of regulation and ramps are also included for each base case; a historic window allows scrolling through time, showing two consecutive days of load, grid-scale solar, grid-scale wind, DG-PV, net load, load-following, regulation, and regulation requirements.

The one-hour ramp statistic is calculated as the difference between the net load at a given time and the net load exactly one hour before. The maximum ramp for each year is reported for the daytime and nighttime. Regulation is calculated as the difference between net load and load-following, where net load is load minus solar and wind, and load-following is a linear interpolation of net load through minute zero of each hour. Regulation is then separated into regulation-up (regulation greater than zero) and regulation-down (regulation less than zero) to remove bias from zero regulation calculated at minute zero of each hour. The 95th percentile of regulation-up and the negative of the 5th percentile of regulation-down are then averaged together to form the regulation requirement. These one-sided confidence bounds combine to form a 95%

confidence interval for regulation, without including the zero regulation calculated at minute zero of each hour.

PLEXOS for Power Systems

The Hawaiian Electric Advanced Planning Department conducted production simulations and modeling analysis with the PLEXOS for Power Systems modeling tool, to perform hourly and sub-hourly analysis (fully incorporating the DER and DR portfolios) and provide hourly dispatches that are then analyzed in PSS/E for system security. The outputs are also used in the Financial Forecast and Rate Impact Model.

PLEXOS for Power Systems models many features of the power systems on Oʻahu, Maui, Hawaiʻi Island, Lanaʻi, and Molokaʻi. PLEXOS simulates 30-years of hourly system operation, subject to fuel limits, renewable portfolio standards, the availability of storage devices, the curtailment (or not) of renewable resources, the typical operation of existing resources, and many other possible restrictions. PLEXOS optimized 30-year expansion plans for Molokaʻi and Lanaʻi.

Input Assumptions and How They Are Used in PLEXOS

PLEXOS used the same set of input assumptions as RESOLVE and PowerSimm Planner to model various long-range plans. This allows for an economic analysis of the various plans and also a view of how each island's power system would operate in the context of several expansion strategies. PLEXOS provides the ability to model both the long-term operation of these systems and the very detailed operations of the system to a degree that is unique amongst simulation models in this area.

The model uses certain profiles as inputs directly, including hourly load, wind generation, solar generation, distributed energy resources, and demand response profiles covering a 30-year period. PLEXOS uses these profiles as inputs to optimize for the rest of the generation to fill in the net load differences. The renewable resources have a mixture of curtailable and non-curtailable resources (such as, firm renewable generators like HPOWER on Oʻahu and PGV on Hawaiʻi Island, and NEM on all islands). Power Purchase Agreements (PPAs) are modeled according to their contract requirements. Existing renewable resources have a specified merit order to curtailment; new variable renewable energy resources are modeled to maximize flexibility. Resource costs are based on capacity, thus PLEXOS models new variable renewables as flexible resources that can be curtailed as necessary before curtailing existing renewable resources.

PLEXOS also models the generation fleet in great detail by using input assumptions that provide the generator attributes: capacity, minimum stable level, heat rates, fuels, variable O&M costs, outages rates, start and stop time, minimum up and down time, minimum and maximum capacity factor restrictions, in-service and retirement dates, and other operating restrictions. Generation build and retirement costs are another input for any potential capacity additions or subtractions, necessary if using the long-term planning feature to optimize resource additions and retirements.

PLEXOS is also able to handle multiple fuels, costs, and contracts allowing their usage to be optimized throughout the year. The PLEXOS model makes use of fuel price forecasts for the different fuels available, as well as any usage requirements and supply limits.

Regulating reserve requirements are another input to the model. PLEXOS will dispatch the generators to provide the required reserves.

Energy storage properties are also inputs into the model. PLEXOS is able to model batteries, pumped storage hydro, and other types of energy storage. The power and capacity requirements are inputs along with any cycle limits, usage costs, efficiencies, and other constraints. PLEXOS will optimize the use of the storage to provide energy and reserves.

PLEXOS is able to output a wide variety of information. Results are available on hourly intervals as well as aggregated on a monthly and yearly basis. PLEXOS can output:

- Overall system production costs, as well as any unserved energy and dumped energy. The outputs provide not only aggregate level costs, but also the individual generator production costs.
- Standard measurements (such as capacity factors) for each generator: fuel usage, costs, energy produced, outages, and generator attributes on an hourly basis as well as monthly and yearly summaries.
- Fuel usage and costs on a per fuel basis or by generator on an hourly basis as well as monthly and yearly summaries.

PLEXOS Model Limitations

A model performs only as well as its realistic and accurate input assumptions, which in turn, directly affects the possibility of attaining quality results.

PLEXOS's primary limitation is its balancing speed with detailed modeling, particularly with various system operating constraints and energy storage. Constraints must be linear, but may not match actual constraints. Complicated fuel constraints requiring a minimum use of some fuels and maximum use of others are one of the largest issues affecting performance. In general, though, the fuel constraints are modeled in PLEXOS but because of this complexity, run times in PLEXOS can vary extensively. For example, introducing energy storage into resource plans caused run times to range between 10 to 48 hours per single run.

PLEXOS is also limited when modeling complicated combined cycle modes while trying to balance speed and performance. While PLEXOS is able to model combined-cycle plants in great detail and in a number of different ways, there are certain configurations for combined cycle operation that require significant modeling intensity and would lead to long run times. In general, simplifications of combine cycle modeling to boost performance are conservative, in that more detailed runs can be performed if the results raise concerns or problems.

Transmission modeling is another limitation. PLEXOS uses a DC load flow model while the Hawaiʻi databases were built to exclude transmission. PLEXOS can still model known constraints related to transmission and could still model transmission in the future if necessary. If transmission data were added, PLEXOS would not perform the modeling of voltage or transient stability necessary for detailed transmission reliability studies. PLEXOS is fully capable of using limitations and operating procedures learned from those studies to be consistent.

Adaptive Planning for Production Simulation

Black & Veatch is running the Adaptive Planning for Production Simulation (AP) model to evaluate the capability and benefits associated with customer-owned assets: traditional Demand Response (DR) devices, customer-owned batteries installed with or without PV systems (DER), and electric vehicles (EV). Our analysis ensures that DR and DER assets are optimized as a portfolio fully considering the flexibility and limitations associated with these assets.

Inputs to the AP Model

AP takes as inputs all data required to characterize utility-owned assets, customer-owned assets, demand, and system security requirements—and evaluates them in sub-hourly and hourly increments. Expanded AP inputs and methodology explicitly address customer-owned assets, criteria associated with their use, and the technology-agnostic value of system security services they may provide. Those inputs critical to the evaluation of DR, DER, and EVs include the following for allocating customer resources to meet system security requirements.

Utility asset expansion and retirement plan. The expansion plan identifies the utility resources available in each year.

Wind and solar variability profiles. Hourly profiles define wind, grid-scale PV, and DG-PV variability. These profiles define the ability of the appropriate resources to generate power in each hour of the evaluation. Sub-hourly profiles are developed by Black & Veatch by applying historical sub-hourly variability to the hourly forecasts. When applying historical sub-hourly data to hourly forecasts, we look for a match between output level and time of day.

Demand forecast. Hourly gross and net demand profiles are used to establish commitment and dispatch requirements and when optimizing load shift provided by customer-owned assets.

System security requirements. Our analysis focuses on those system requirements that can be partially met by customer assets. These include the need for capacity, inertial response/fast frequency response, contingency, wind/solar variability regulation, demand regulation, ramping, and regulating reserve. Recognizing that the islands' need for system security is also under evaluation, we analyze against those system security requirements that defined at the time of our analysis.

Customer resource potential. Traditional DR resource and EV potential is provided by Navigant. Customer battery potential is provided by uptake models based on avoided cost value of storage provided by Black & Veatch. The potential defines the maximum amount of customer resources that are available in each year to shape demand and provide system security.

Customer resource criteria. Certain criteria limit the ability of customer resources to provide multiple services at the same time. Typically, a customer resource (such as a water heater) is limited to simultaneously providing one service that increases load (e.g., load shift to the middle of the day) and one service that decreases load (fast frequency response). In addition, there are limits on the frequency and duration of customer resource calls. These limits are considered in determining the most cost-effective use of limited DR, DER, and EV resources.

Outputs

The AP model creates a comprehensive set of outputs that support a number of subsequent evaluations in the overall PSIP and DR evaluation processes. These analyses required full production simulation modeling of the generating system including gross demand, centralized firm and variable generation assets, PPA contract obligations, security requirements, DER volumes, and DR products. These outputs include quantifying and valuing grid services as well as the following results provided to other models

Avoided cost value of storage. The value that customer-owned batteries deliver to the generation system provides an estimate of the incentives that the Companies can use to encourage customer battery build-out. This value—specifically the ability to load shift and provide regulation—is determined by modeling the generation system without directly competing resources (DR, DER, or load shift batteries), then evaluating the same generating system configuration with an incremental amount of load shift and associated regulation capability. The results feed storage uptake models.

Optimized DR and DER profiles. DR and DER uptake between the best use of various utility and customer assets is optimized through full simulation of each hour of each year of the evaluation period. The optimization considers the customer resource criteria—limits in the ability of customer resources to provide multiple system security services at the same time—and the optimal use of customer assets. The optimization results are translated into 8,760 profiles for each year in the evaluation period for each service provided by DR and DER. The model provides yearly peak use (in MW) by the DR and DER programs. These results are transmitted to other production simulation models and used to determine the cost of the DR programs.

Value of Services

The value of service analysis attempts to segregate, to the best degree possible, the value of each independent grid service to the generating system. This is done by evaluating top down, bottom up, and by service bundles. Service bundles recognize that certain technologies provide a suite of services that cannot be easily decomposed. For example, an ICE unit can provide inertia, regulation, and energy while online; it can provide replacement reserves when offline and also provides capacity. A service bundle, in this example, allows a top down comparison to the bottom up aggregation of the individual services.

In general, grid services are valued by removing some portion of assets that provide the service as their primary function, then adding a "service proxy asset" that provides the specific service into the system in incremental steps. The service proxy asset is provided at a level quantity for all hours and at zero cost to the system (no capital or operating cost are associated with the service proxy asset). The difference in generating cost between a run that includes the service proxy and one that does not can be used to calculate the technology-agnostic value attributed to that service. By adding in the service proxy in steps, we can see how the value of the service tracks against the quantity of service added and, as such, at what point the incremental service substantially declines in value.

Value of services methodology will be described in greater detail in the February 2017 DR Application.

DR and DER Optimization

A customer participating in DR (for example, with their water heater or battery) has options—called DR products—on how their DR asset (the water heater or battery) can be used. AP evaluates available DR products, both individually and in combination, to identify the optimum DR portfolio mix. AP fits the products together either to substitute for physical assets that would otherwise need to be added or to address system security needs in a more economical manner.

Combining individual DR product potential into a portfolio is limited in the ability of its end devices to provide multiple services simultaneously.

Typically, an end device can simultaneously provide one load-building and one load-reducing service. For example, a water heater (participating in a pricing program) that uses midday solar generation to build load can also provide fast frequency response (FFR-a reduction in load after the sudden loss of a generating asset). During evening hours when the water heater is reducing load under the pricing program, however, it cannot also provide the load reducing FFR service.

Similarly, a water heater cannot simultaneously provide both FFR and regulating reserve (reducing electricity use because other customers suddenly need more) because FFR causes the end device to shut down thus making it unavailable to provide any other service. As such, the DR potential for each product must be managed to prevent over allocation of end-use devices.

The value of individual DR products will change over time. This is because the generating system is in a state of continual change with the adding and subtracting of grid-scale resources, changing resource mixes, the continuous adding of consumer resources, and evolving loads (electric vehicle loads for example)—all contributing to make each year's DR and DER value proposition unique. Thus, how the DR and DER portfolio is utilized can be expected to vary over time.

AP bases how customer-owned assets are used hour to hour on the best value derived from the asset. Since both the DR and DER potential (air conditioner load is higher in the summer and peaks during midday) and the needs of the generation and transmission system are dynamic by hour, AP allocates DR and DER potential for each hour. The allocation is complex as some system constraints are dynamic. For example, the system security requirement that sets the FFR need is based on the unit commitment, which is determined by the allocation of DR end-use devices for regulating reserves and load shifting. Given the finite DR and DER potential, the optimal allocation must be evaluated for each hour.

Generation Adequacy Modeling

In addition to evaluating DR, Black & Veatch performed Loss of Load Probability (LOLP) modeling for certain O'ahu cases to help confirm reliability measures associated with those cases. Black & Veatch uses a proprietary LOLP model (AP for LOLP) to calculate reliability measures for generation-demand systems. The LOLP model is a component of the Black & Veatch Adaptive Planning suite. The model uses the same input format as the Adaptive Planning for Production Simulation model.

AP for LOLP considers the ability of firm generation, variable renewable generation, demand response, and utility load shifting batteries to meet capacity needs. It uses a

Monte Carlo simulation solution methodology. For this analysis, the Monte Carlo model evaluates the ability to meet load each hour of each year with many (5,000) simulations evaluated for each year. For each of the 5,000 simulations, key variables that affect LOLP – demand, capacity of variable renewable generating assets, DR load shift potential, and asset forced outages – are allowed to vary.

AP Model Limitations, Shortcuts, and Simplifications

AP incorporates a detailed understanding of energy demand, wind resources, solar resources, system security requirements, operating constraints, and more. On an hourly basis, it allocates the complex array of utility-owned and customer-owned assets to meet energy and system security needs. To reduce the complexity of factors not directly related to DR and DER, AP has been configured to assume that the data used to characterize grid-scale assets and system security needs is completely accurate—in other words, our knowledge of the future is perfect.

Grid-scale assets sometimes break down unexpectedly. Black & Veatch uses a probabilistic model to assign when forced outages due to breakdowns will occur. Forced outages are assigned and fed into AP at the beginning of each study —forced outage timing is not modified within AP while assigning forced outages external, AP ensures consistency across model runs, it limits the ability of AP to consider changes in system security needs for the full range of unexpected system upset conditions.

When identifying system security needs, AP considers the system at a high level. Power flow, system transients, and locational limitations are beyond its capability. Additional modeling of various system states using specialized tools is required to identify system security needs related to transients and location.

DG-PV and Customer Energy Storage System Adoption Models

The DG-PV Adoption Model was used to address DER integration. The model forecasted market DG-PV and DG-PV paired with battery customer adoption amounts for self-supply, SIA, and potential future DG-PV products while also considering related integration costs. The model forecasted DG-PV customer adoption amounts based on historical market behavior and future projections of costs, electricity prices and incentives. The model can be used to fine-tune the DG-PV forecasts as technology costs, tax credits, grid service compensation rates, retail rates, or other underlying assumptions change.

The Customer Energy Storage System Adoption Model forecasted customer adoption of distributed storage when compensated at avoided cost for providing grid services through the proposed DR programs. The model can be used to fine-tune distributed storage forecasts as technology costs, tax credits, value of storage figures, or other underlying assumptions change.

Input Assumptions and How They Are Used in the DG-PV and Storage Update Models

Both models use a common set of input assumptions to determine the results provided for creating our action plans.

The DG-PV and the Customer Energy Storage System Adoption model takes into account the following:

- Addressable populations to determine the market size in terms of number of customers in each rate class that could potentially adopt DER.
- Hourly customer load profiles by island and rate schedule to determine the optimal DER system size and the energy flows (when DER is used and exported; when a battery is charging or discharging).
- Unitized hourly DG-PV production profiles by island to determine the optimal DER system size and the energy flows (when DER is used and exported; when a battery is charging or discharging).
- Tariffs and retail electricity price projections to determine the avoided cost resulting from customer DER use (customer economics analysis).
- Export energy compensation rate to determine the compensation for energy exported to the grid in a future grid-export program (customer economics analysis).
- The value of storage (for providing grid services) to determine the revenue stream received by DER systems with storage (customer economics analysis).
- Investment tax credit assumptions to determine the state and federal income tax credits that reduce the effective DER system cost (customer economics analysis).
- System cost assumptions to calculate the effective cost of DER system (customer economics analysis).
- The weighted average cost of capital to determine the net present value of the DER system (customer economics analysis).
- Integration costs to determine the new installations that are projected to be above the circuit hosting capacity that incur an additional one-time dollars per watt integration cost (customer economics analysis).
- The rate of inflation because all adoption modeling relationships and results are calculated in real dollars, so inflation is used to convert nominal inputs to real dollars as necessary.
- The uptake relationship to determine future uptake as a percent of the addressable population (derived from customer economics and uptake relationship regression equation).

DG-PV and Storage Update Model Outputs

Both models generate a common set of outputs and use them for similar purposes. The DG-PV and the Customer Energy Storage System Adoption models output:

- The number of customers electing to install a DER system in each year by island and rate class to scale up hourly energy flow profiles for the production simulations and DR modeling, and to define the addressable populations for stand-alone storage uptake (DR).
- The optimum system size for the average customer in each island, rate class, and program.
- The DG-PV installed capacity, and battery storage installed capacity for each year by island, rate class, and program. (The customer uptake and optimum system size combine to result in the installed capacity for all three results.) These results are then provided as input to the production simulations and DR modeling.
- The number of participating and non-participating customers in each DER program. These results are then provided as input to the DR modeling.
- Hourly profiles for energy flows (when customer energy is used or exported; when a battery is charging or discharging). These results are then provided as input to the production simulations and DR modeling.

DG-PV and Storage Update Model Abilities and Limitations

Both models can account for:

- Future customer economics.
- Rational customer technology adoption behavior based on past behavior in Hawai‘i and future customer economics.
- Future DER programs as defined in the assumptions (for example, future grid export).

The models are limited in their ability to:

- Forecast undefined future programs and tariffs. Assumptions must be made to define specific program attributes that impact customer economics (for example, future grid export).
- Manage complex and numerous future program options. While capable of handling one or two options, but numbers of options beyond that require other methods.
- Forecast rate classes with limited historical data because there is not enough data to regress historical relationships (for example, Schedule P on Maui, Lana‘i, Moloka‘i, or Hawai‘i Island). Forecasters, however, can make adjustments outside of the model (such as including future Schedule P uptake) to lessen impact of model limitations.

DG-PV and Storage Update Model Process

The financial model (retail electricity rates from production simulations), the AP model (value of DR and storage), and other assumptions (such as system costs, DER attributes, and investment tax credits) act as inputs.

The DG-PV and Customer Energy Storage System Adoption models then:

1. Update these assumptions:
   - Validate and compare these new assumptions against prior assumptions.
   - Input the validated assumptions into the model analyses.
   - Conduct test runs and ensure the results are reasonable.
   - Add the sources of the assumptions data as necessary to ensure validate results.
2. Determine the optimum system size by conducting system size optimization hear map runs for each island, rate schedule, and DER program.
3. Execute and iterate the uptake models by rate schedule and by DER program, with and without integration costs, for each island (generally 12–16 iterations).
4. Summarize and validate the capacity forecast results by comparing the current results with prior forecasts to ensure they are reasonable, then conduct additional model runs if necessary.
5. Prepare the forecast package—summary files of capacity, energy, counts, hourly profiles, and customer participation details—for distribution.
6. Distribute the forecast package to the production simulations and the DR model.

PSS/E Software for System Security Analysis

PSS/E performs simulations for a specific set of conditions (such as unit dispatch and system load). Load flow simulations are performed to determine potential overload and voltage problems under steady-state conditions for various system configurations (normal, N-1, or N-1-1). Dynamic simulations are performed to evaluate frequency, voltage, and rotor angle stability of the transmission system and its components.

We perform multiple simulations using Python, a programming language used with PSS/E to automate functions in PSS/E simulations. We developed (internally) a tool to screen the hourly dispatch from the production simulations to select "typical" and "boundary" hours in a particular year based on frequency response profiles for loss of generation contingency events. The screening tool runs a PSS/E transmission system model that has been condensed to an equivalent single-bus system model. The screening tool analyzes the largest loss of generation contingency for every hour of the year and calculates the frequency nadir; along with the FFR1 and FFR2 capacities required to meet TPL-001. Data from the screening tool is used to select typical and boundary hours for evaluation and to create histograms and duration curves of the frequency nadirs for the entire year.

In our system security process, we run a number of steps—and iterate them—to analyze various system conditions. We run all these analytical processes for each resource plan for a single year. We perform analyses for selected years (5–6 years) to account for the significant changes in a resource plan (such as resource additions, resource retirements, load, and increasing amounts of renewable generation).

Frequency Stability Analyses for Loss of Generation (under frequency)

1. Screen production simulation hourly data to select a "typical" and "boundary" hour for select years for each resource plan core case. Create a histogram and duration curve for the final report.
2. Setup the dispatch case in PSS/E and the associated PSS/E dynamic file for each hour. If the resource modeling needs to be modified or new resources need to be added, this setup time might be extended. A dispatch table is created as needed.
3. Run the dynamic simulation for each dispatch case by tripping the largest generator. Analyze the results and estimate the FFR1 capacity to meet TPL-001. If there is UFLS, add FFR1 capacity to the PSS/E case and rerun the simulation. Continue adding FFR1 capacity until there is no UFLS for Oahu (or one block of UFLS for Maui and Hawai'i Island). This can require several iterations. Plot the results for the final report.
4. Repeat step 3 with FFR2 capacity to determine the FFR2 requirement for each dispatch case, depending on the resource plan.
5. Repeat step 3 with PFR capacity to determine the PFR requirement for each dispatch case.
6. For O'ahu, run a sensitivity analysis to determine FFR1, FFR2, and PFR requirements with AES curtailed to the full capacity of Kahe Unit 5 for the typical and boundary hours. Plot the results for a final report.
7. Compile all simulation results, tables, and graphs for the final report.

Frequency Stability Analyses for Electrical Fault (over frequency)

1. Screen production simulation hourly data to select an hour with high DG-PV. This step may not be required if the hours selected for the loss of generation analysis has a high capacity of legacy DG-PV.
2. Set up the dispatch case in PSS/E and the associated PSS/E dynamic file for each hour. Create a dispatch table for the final report.

3. Run dynamic simulation for a normally cleared fault on every transmission circuit in the system. Analyze and plot the results for the final report. Develop a summary table of all normally cleared faults for the final report.
4. Determine potential mitigation options such as addition of PFR or running units in VPO. Select a line fault that results in the worst frequency response or system collapse and run a dynamic simulation to determine the PFR capacity. Increase or decrease PFR capacities to meet TPL-001 requirements.
5. With the mitigation options added to the dispatch, run dynamic simulations for a normally cleared fault on all transmission circuits. Plot the results for the final report. Develop a summary table for all transmission circuits.
6. Repeat steps 3 and 5 for delayed clearing faults, if applicable.
7. Compile all the simulation results, tables, and graphs for the final report.

Voltage Stability Analysis (QV)

1. Screen production simulation hourly data to select an hour with high load. The QV analysis was performed from 2019 through 2021.
2. Set up the dispatch case in PSS/E.
3. Run QV analysis for N-2 contingencies for Oahu (N-1 contingencies for Maui and Hawai‘i Island) to determine reactive power requirements for each critical bus to meet bus voltage set points ranging from 1.0 PU to 0.90 PU. Analyze data, develop summary table and plot QV curves for final report.
4. Perform sensitivity analysis for dispatch cases that do not meet reactive power requirements. Add synchronous condensers and repeat steps 2 and 3. Analyze data and repeat if necessary. Note that in some cases, additional load flow analysis is required to determine mitigation.
5. Compile all simulation results, tables, and graphs for the final report.

Minimum Fault Current Screening

1. Screen production simulation hourly data from 2019 through 2021 to determine if minimum fault current requirements are met.
2. Add synchronous condensers when resource plans violate minimum fault current criteria.

Financial Forecast and Rate Impact Model

The financial model takes inputs from the Production Simulation system cost files, as well as other general planning and forecasting assumptions in order to calculate revenue requirements and associated bill impacts for each theme.

Table C-1 details the major financial model inputs required and the sources of the input.

Inputs	Source
Capital expenditures	Planning System Cost files
Plant addition dates	Planning System Cost files
Sales	Planning System Cost files
Fuel costs	Planning System Cost files
Purchase power costs	Planning System Cost files
Operating costs	Planning System Cost files; Historical actuals
Removal costs	Property Accounting
Depreciation rates	Approved depreciation rates; Management forecast
Inflation rates	Blue Chip GDPPI forecast
Interest rates	Management forecast
Tax rates	Federal and state tax codes
Equity ratio	Management analysis
Allowed ROE	Approved rate cases
Historical Financial Statements	General Ledger
Weighted average cost of capital	Management analysis

Table C-1. Financial Model Inputs

The inputs are entered into the financial model calculate its results. See Financial Forecast and Rate Impact Model (page H-80) for an explanation of how the financial model calculates bills, profit and loss, cash flow, revenue and rates, debt and equity, balance sheet assets and debts, and capital expenditures.

Table C-2 details the major outputs of the financial model.

Outputs	Description
Revenue requirements	Total revenue requirements based on all the cost inputs from above.
Average residential rates	Average rates based on the cost inputs from the revenue requirements divided by the sales forecast.
Typical residential bill impact	Typical bill based on 500 kWh monthly usage.

Table C-2. Financial Model Outputs

The financial model takes input from various other sources, primarily from the production simulations.

The financial model—and the PSIP process as a whole—accounts for but does not reflect detailed planning and forecasting for balance of business capital expenditures. There may be situations where balance of business capital expenditures are a higher priority than PSIP capital expenditures, or vice versa and that some re-prioritization is needed.

RESOLVE OPTIMIZATION MODEL AND LONG-TERM PLAN DEVELOPMENT

Achieving a 100% RPS in 2045 would require dramatic changes in how energy is generated and used. Traditional resource planning has focused on matching the peak load and reliability needs of the system with thermal generating resources to maintain the quality of service. Planning with increasing levels of energy from variable renewable resources shifts the planning paradigm away from maintaining sufficient peak capacity towards determining the quantity and type of measures needed to integrate those resources at least cost. This requires both new planning tools and a broad perspective on how energy is produced and consumed, with the potential addition of transportation as a substantial new end-use to the electric sector.

Given the multi-decade lifetime of infrastructure built today, the decisions made now and in the near future have a potentially significant impact on the ability to meet the 100% RPS target in 2045 as well as the ultimate total cost of achieving this goal. However, the long timeline also means significant uncertainty exists about future technology costs and capabilities, fuel prices, and other factors that may have a major impact on the cost of the transition. The Companies and Hawaiʻi have no control over such factors; these are the future conditions that are essentially inevitable on the islands. Understanding these factors and how they affect the cost effectiveness of investments made today is critical. Near-term decisions should be both consistent with the islands' long-term goals and robust against a range a future uncertainties. Another necessary step is therefore to identify the controllable decision levers available in formulating a robust, least regrets plan to best handle what happens in the future.

The difference between planning elements that happen to the islands served versus those that are decision levers is dependent on many complex and interacting factors. Global market prices for fuels and technologies, as well as technological innovation, fall into the first category. Others (such as battery procurement) can be directly decided by the Companies. But what about customer behavior, renewable resource portfolio diversity, or transportation infrastructure? These typically fall outside of the traditional Company planning cases, but can be influenced by tariff design and policy development. Identifying these factors early in the planning process, engaging stakeholders in a discourse around the policy issues, and arriving at a consensus about the policy directives is critical to create long-term policy certainty and thus enable effective planning.

Energy and Environmental Economics (E3) was retained to address these key questions. E3 has multiple contracts with the California State Agencies to support their long-term planning efforts to meet both RPS and greenhouse gas (GHG) reduction targets and were responsible for developing the four United States deep decarbonization cases used in the COP 21 process to help reach climate agreements in Paris, December of 2015. E3 also has a long history working with both the Hawaiʻi Public Utilities Commission and the Companies on energy issues in Hawaiʻi.

In this analysis, E3 first investigated what the least cost planning decisions for the Companies should be given current policy and economic trends on the islands to create a business-as-usual case. E3 then developed cases that satisfy potential policy directives to adapt to higher renewables. The cases account for the value of creating a portfolio with more diversity, more control of variable renewable resources, the evolution of the transportation sector to electric vehicles powered by hydrogen or synthetic natural gas, and flexible loads capable of responding to supply-side needs. E3 compared the costs of each of these cases and the decisions that need to be made to achieve them, forming the basis for discussion in a state policy decision process.

Case Development

Based on E3's prior work for our April 2016 updated PSIP to explore the operational impacts and integration requirements of higher renewable penetration levels on the islands, E3 also identified and included in their analysis several current trends with significant implications for the Companies' planning processes.

These trends include:

- Low renewable portfolio diversity: high levels of customer adoption of DG-PV.
- Non-dispatchable renewable supply: limited utility control (via curtailment) over renewable generation.
- Load inflexibility: limited ability of loads to respond to supply conditions.

Figure C-3. illustrates how these trends might manifest themselves in a 100% renewable generation case.

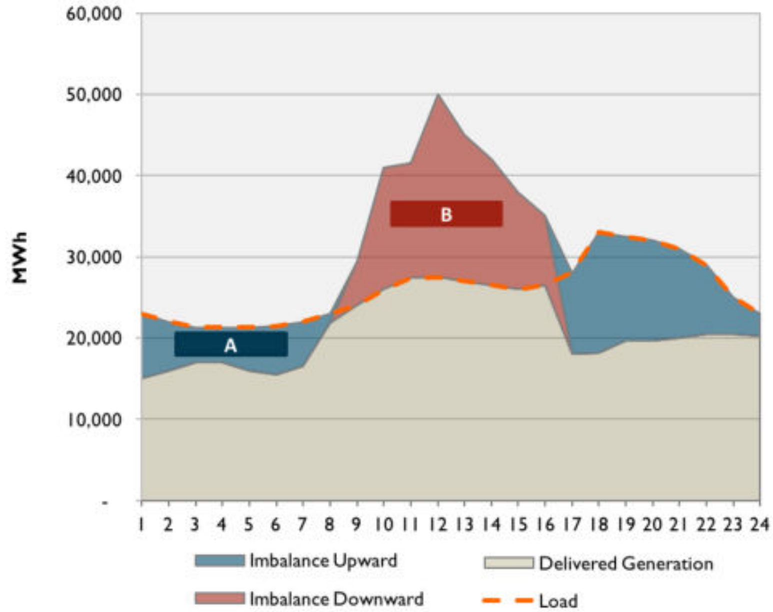


Figure C-3. Example Dispatch at 100% Renewables

In this case, the renewable portfolio consists of largely solar energy, so energy production is concentrated during the daylight hours. The load is assumed to be inflexible. The combination of these factors results in oversupply in the middle of the day (imbalance downward, B) and undersupply at night (imbalance upward, A). If the renewable generation were not curtailable, the consequence of the daytime oversupply would be an over-generation reliability event. The nighttime undersupply results in a traditional loss-of-load reliability event. Building storage to meet such imbalances is the approach that is often considered, but such storage requires substantial capital investment and is potentially unsuited to imbalances that may persist over a number of days, or even weeks or months. Renewable portfolio diversity to reduce the oversupply levels or the deployment of load controllability equipment may be more cost-effective integration alternatives. Incorporating the available alternatives into a single modeling framework is necessary to identify trade-offs and synergies among them, and optimally combine them.

E3 investigated a series of cases exploring potential futures in Hawaiʻi to determine the planning solutions needed in each one. These cases are defined by the factors on the system described by the categories in Figure C-4. Within each of these categories, E3 investigated two or more different potential futures. Each case is defined by a set of assumptions describing customer behavior, renewable diversity, and transportation infrastructure, reflecting the decisions the Companies may have limited control over but may be impacted by state-level policy developments.

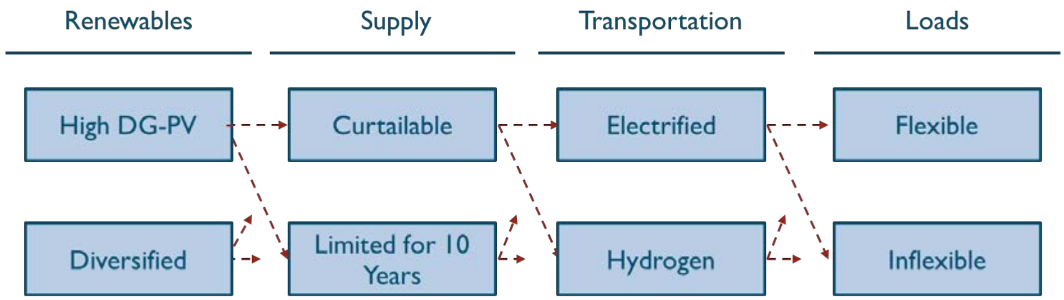


Figure C-4. Case Drivers of Potential Hawaiian Electric Futures

These cases explore the impact of the following policy decision points for Hawai'i that depend on price and political drivers:

High consumer PV adoption versus diverse resource portfolio: E3 analyzed the differences among integration solution needs when consumer adoption of DG-PV is allowed to grow to high levels compared to a more diverse portfolio of resources.

Curtailment of supply: E3 explored the impact on resource plans of whether the Companies have full control over curtailing new generation resources, compared to a case where contracts or technological constraints limit the curtailment capability for some time.

Low-carbon economy transition: To decarbonize the entire economy of Hawai'i, either fossil-fueled services (such as transportation) must be electrified and served by clean electric generation, or a transition must be made to using gas (such as hydrogen or synthetic methane) as an energy carrier. E3 considered both load electrification and gas (hydrogen or synthetic natural gas) transition cases. Under the gas transition case, gas is produced on the island and functions as a controllable load with a daily consumption requirement. Conversely, in the base electrification case, E3 used electric loads (including EVs) to balance renewable generation. Previous work has shown that electrification does not provide the same flexibility as the gas generation path but could ultimately be a less expensive path for decarbonizing Hawai'i.

Load participation: Increasing levels of efficiency and substantial growth in flexible loads are a cornerstone of most long-term high RPS cases E3 has studied so far. The levels of flexible loads are partially dependent on tariff design, market development, technological capabilities and pricing for distributed generation technologies. The cases explore the amounts and types of flexible loads needed to substantially mitigate integration challenges.

The simple matrix (shown in Figure C-4) leads to eight Cases that E3 described, provided input data for, and modeled. The matrix is not meant to be an exhaustive list of all key drivers or decarbonization paths, but is an attempt to develop a workable number of cases suitable to explore initial analysis and stakeholder discussion. The number of cases can be expanded to include other critical elements or additional sensitivities based on initial results as well as feedback from either the Commission or key stakeholders. For each case, E3 also explored sensitivities to the uncertainty around market fuel and technology pricing.

Modeling Approach

Developing Case Data

Variable renewable energy poses challenges to traditional electricity sector planning and procurement as well as day-to-day reliable operations of the grid. Analyses of these challenges generally focus on near-term issues related to supply-side flexibility. These challenges can often be solved within traditional paradigms of supply-side dispatch. However, such a focus may ignore the broader context and longer-term challenges and opportunities presented by transitioning away from imported energy, not just of the electric sector, but for the energy system more broadly. For instance, a large transformation in transportation away from internal combustion engines has major implications for the electricity sector that need to be factored into long-term energy planning. E3 has drawn on its work in developing deep decarbonization paths for both California[5] and the United States[6] to develop multiple paths and a strategic vision for transforming Hawai‘i's energy future. Combinations of the case drivers shown in Figure C-4 form each of the cases investigated. Case development consisted of the following three tasks.

Task 1. Demand Case Development. As the first step in developing the vision for the electric sector under a 100% renewable penetration, E3 focused on the potential for other energy system choices to impact the electricity sector. This focused on new electric loads from:

- Direct transportation electrification (that is, electric vehicles)
- Building electrification
- Electric fuel production: hydrogen electrolysis and power-to-gas synthetic natural gas

These new loads affect the load shapes of the electric sector, the overall demand for electricity, and the potential supply portfolios that can meet their demand. This is a very important context for the electricity sector, not just for the challenges that these new loads pose, but for the opportunities they present. This is a first-cut, case analysis to assess the scale of these potential impacts. E3 developed energy transformation case demand forecasts based on previous work developing deep decarbonization paths for

5 https://ethree.com/public_projects/energy_principals_study.php.
6 http://unsdsn.org/wp-content/uploads/2014/09/US_DDPP_Report_Final.pdf.

California and the U.S. These focused on key choices in the transportation sector and buildings:

- Light duty vehicles
- Heavy-duty vehicles
- Buses
- Thermal end-uses (water and space heating)

E3 utilized all available data for Hawaiʻi to develop a realistic assessment of future electricity demand from activities in these sectors.

Task 2. Renewable Portfolio Development. In this task, E3 developed prospective renewable portfolios for supplying levels of overall electricity demand developed in Task 1. The first portfolio is composed of reference renewable supply assumptions, with high levels of DG-PV. Additional portfolios are based on existing renewable energy potential data and reflect policy direction to procure the best prospective portfolios to minimize supply and demand imbalances (that is, 100% solar would exacerbate supply and demand imbalances) versus cost and development potential constraints. The level that a resource can be curtailed is also factored into the portfolios to reflect potential transition times to the Companies' full control of the renewable fleet, including DG-PV systems.

Task 3. Load Development. E3 first assessed the flexibility from the new loads detailed in Task 1. Many of these loads come associated with storage, which allows them to mitigate their demands on the electricity sector. For example, a car battery connected to the grid offers the ability to delay or advance its charging needs based on its inherent chemical storage capacity. End-uses in buildings offer thermal storage to perform activities like pre-cooling and pre-heating to manage loads with regards to supply conditions. Electric fuel production may be the most flexible of all, taking advantage of existing gas infrastructure or hydrogen storage to flexibly operate plants during periods of over generation.

E3 also examined permanent load shaping. Here, targeted energy efficiency can reduce loads during times of the day where consistent supply deficits occur. For example, aggressive lighting efficiency can reduce nighttime load in a high-solar case, increasing the coincidence of demand and supply. Permanent load shifting could provide pre-cooling opportunities at mid-day to reduce nighttime cooling loads.

Developing Optimal Resource Portfolios for Each Case

For each case and selected fuel price and capital cost sensitivities, E3 used its investment model RESOLVE to develop optimal resource portfolios for meeting the RPS targets. (RESOLVE is an optimization tool that selects a least cost portfolio of renewable resources and integration solutions over a chosen time horizon. E3 built it for the California State Agencies to study cost-effective integration solutions including demand response and a range of storage technologies, and to determine the value of regional integration in mitigating renewable integration costs.)

Price sensitivities are developed under each of the cases to include plausible future market price trajectories for both fuel and capital investments.

A number of factors influence the cost effectiveness of a conversion of oil-fueled generation to LNG, including capital expenditures necessary for the conversion, oil and LNG price trends and spreads, and quantity of energy generated by the converted plants. The payback of thermal capital investments also depends on the expected energy demand, which is influenced by renewable energy production and energy use patterns.

The optimal resource mix depends in part on the price trajectory of energy storage technologies. E3 does not have confidence that an accurate prediction of energy storage technology price can be made out to 2045. Therefore, E3 considered several price trajectories to evaluate the expected price impact on the resource mix.

Figure C-5 shows the conceptual effects of uncertain storage pricing.

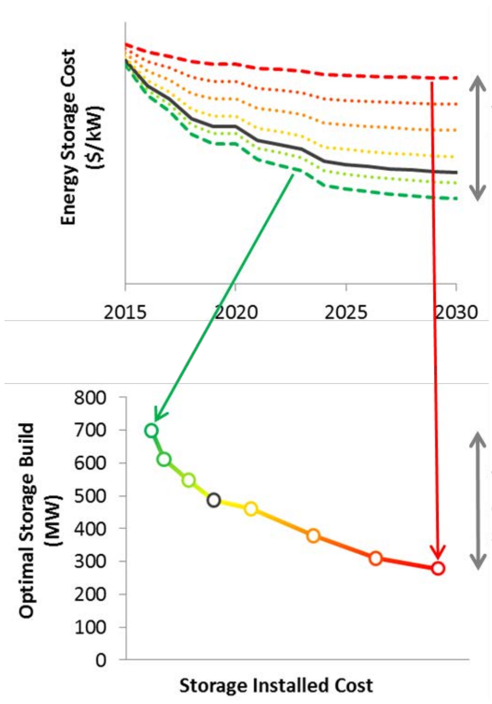


Figure C-5. Conceptual Effect of Storage Price Sensitivity

Beyond energy storage, a broad suite of integration solutions was employed to meet the RPS targets (Table C-3). The applicability of many of these strategies relies on decisions made outside the electricity sector itself (for example, EV penetration determines the availability of EV load to manage imbalances).

Resource	Balancing Direction	Balancing Timeframe	Resource Potential
Flexible building thermal loads	Both	Seconds to hours	Depends on electrified thermal end-uses, controllable equipment, and customer participation.
EV charging management	Both	Seconds to hours	Depends on available public and private infrastructure as well as overall electric vehicle penetration.
Hydrogen electrolysis	Both	Seconds to weeks	Depends on demand for hydrogen in other sectors (primarily transportation).
Power-to-gas synthetic natural gas	Both	Seconds to months	Depends on demand for gas and available gas storage facilities.
Targeted energy efficiency	Upward	Hours	Depends on end-use electricity demands.
Permanent load shaping	Both	Hours	Depends on building loads and customer incentives.
Battery storage	Both	Seconds to days	Effective balancing, but at high capital cost and efficiency penalty.
Pumped storage hydro	Both	Seconds to months	Depends on site availability.
Flexible renewable generation	Upward	Minutes to days	Depends on available renewable fuels (geothermal).
Flexible thermal generation	Both	Seconds to hours	Depends on price of available fossil fuels.
Curtailment	Downward	—	Depends on controllability of renewable resources.
Interisland transmission	Both	Seconds to hours	Balancing benefits depend on the complementarity of load and renewables being connected.

Table C-3. System Balancing Options

How these balancing solutions are implemented in the context of a low-carbon electricity grid is shown in an example from the U.S. deep decarbonization paths analysis (Figure C-6). This chart shows the Western Interconnection in a high renewables case during a week in March. In this case, high penetrations of renewable generation necessitate the dispatch of flexible fuel production, battery storage, flexible building loads, and EV charging in order to effectively manage periods of over- and under-supply. Those loads are available for dispatch because of the electrification of transportation under this case. As control over energy supply is reduced, participation from other resources-like loads are a critical element for maintaining a low-cost, reliable electricity grid.

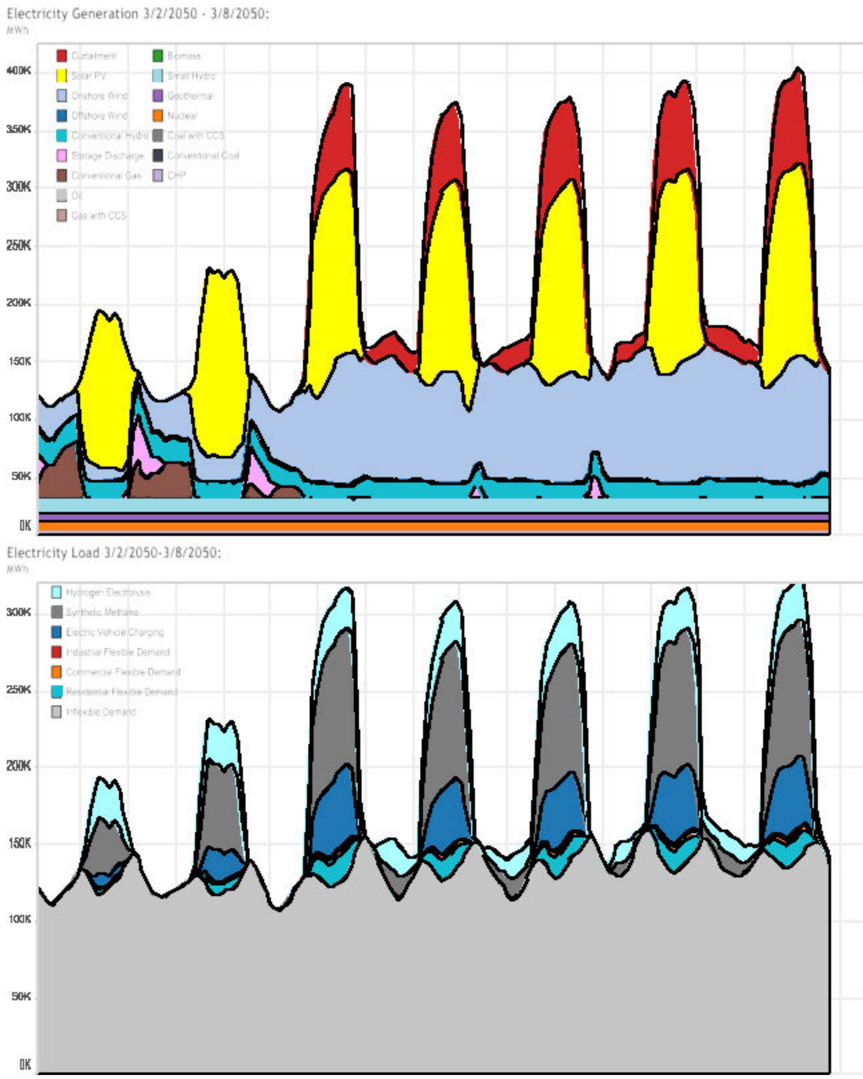


Figure C-6. Dispatch at 100% Renewables: Supply (top) and Demand (bottom)

Economic Selection of Optimal Renewable Integration Solutions using RESOLVE

Planning the development of a 100% RPS compliant electric energy system presents a number of challenges. The plan must choose a portfolio of varied resources that work in concert to reliably meet consumer electricity demand while accommodating the variability of renewable energy resources. Every hour of the planning horizon, the system must satisfy several operational constraints including reliability needs, for example generator minimum generating levels, ramping constraints, contractual obligations, and reserve requirements. Figure C-7 shows a hypothetical day when generating resources must operate to meet the following constraints:

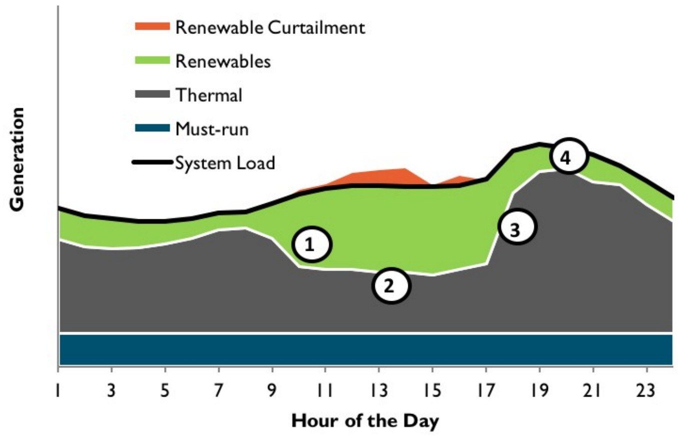


Figure C-7. Renewable Integration Challenges

Key to Figure C-7 numbers:

1. Downward ramping capability: ramp capability must be available to meet morning ramps as solar production increases and the net load drops.
2. Minimum generation: resources must be capable of lowering their output sufficiently, either by turning off generation, or ramping down output, such that low midday net loads are balanced while reliability requirements are still met.
3. Upward ramping capability: ramp capability must be available to meet capacity needs as solar production falls in the evening.
4. Peaking capability: peak loads must be met, often after solar generation has dropped off.

There are many different combinations of resources that can be included in the resource portfolio to meet reliability needs, so determining the least cost portfolio must be done through an optimization framework. Figure C-8 shows the resource mix under three hypothetical renewable integration strategies.

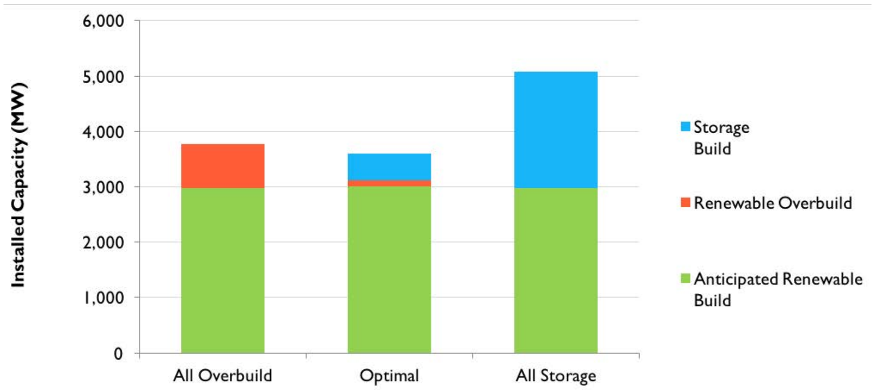


Figure C-8. Hypothetical Renewable Integration Strategies

The lowest cost portfolio of renewables and integration solutions at any point in time is a mix of resources that minimizes both operating costs and capacity expenditures over the planning horizon. The value of each integration solution changes over time depending on the evolving needs of the system. Those selected in an optimal resource portfolio offer the greatest net value over their lifetime in combination with the other resources selected. Some technologies may be stepping stones to longer term portfolios. In addition, a robust analysis incorporates the costs of the enabling technologies on the grid (for example, interconnection, control systems).

Figure C-9 depicts an optimal tradeoff between renewable overbuilding and other integration solutions. The optimal point for each resource is where the benefit of the marginal unit of any resource to the system is equal to its marginal cost. In reality, each type of resource adds a dimension to the optimization; each combination of resources has complex operational interactions. Finding the least cost solution requires a sophisticated optimization model that treats operational and investment costs while satisfying operational and reliability constraints.

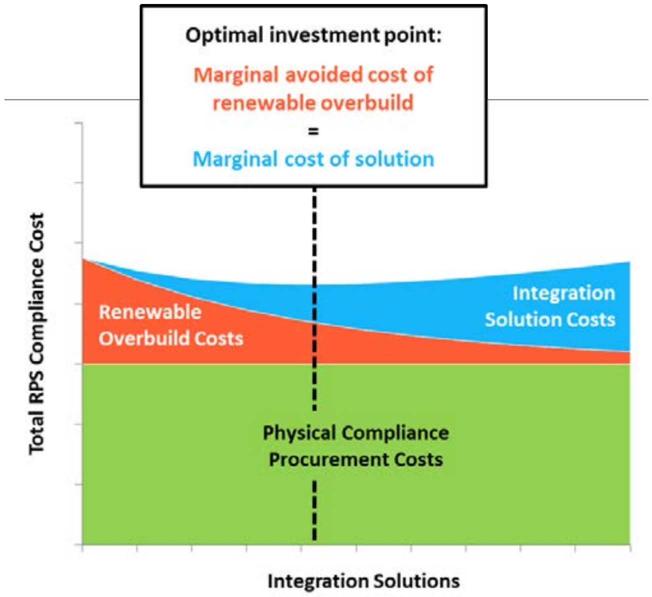


Figure C-9. Tradeoff Curve Between Integration Strategies

The optimal resource mix depends on a number of assumptions about the future state of the world. An optimal resource plan should be robust to uncertain future trajectories of fuel prices, technology costs, and consumer adoption of DER.

For each case investigated in the analysis, E3 used its RESOLVE model to optimize resource portfolios over a planning horizon out to 2045. RESOLVE builds on the REFLEX advanced production simulation model to optimize investment decisions subject to detailed hourly operational constraints including reserve requirements, ramping limitations, and unit-commitment constraints. Using its demonstrated methodology, Ascend Analytics is determining the electric power system's operating and contingency reserve requirements on an annual basis. These reserve requirements serve as input data for RESOLVE, which then determines an optimal resource plan that adjusts the portfolio of resources on an annual basis. RESOLVE selects the optimal portfolio of resources to be installed in each year, choosing from generation retrofits, battery energy storage, demand management, thermal generation, and renewable generation. The solution found by RESOLVE co-optimizes investment and operational costs.

E3 is developing long-term strategic options for the electric sector under high penetrations of renewable energy. Over the full planning horizon and considering the uncertainties involved, E3 is identifying near-term least regrets planning decisions.

POWERSIMM PLANNER MODELING TOOL

The electric supply system with increasing amounts of variable generation has broad needs for flexible generation to manage increased daily ramps, greater regulation requirements, substantial amounts of energy storage—all of which require closer analysis. Uncertainties also include the physical dynamics of weather-driven renewable generation and load, uncertainty in adoption rate of DER, storage system capabilities and costs, and market prices of fuel and emissions.

Ascend Analytics uses its PowerSimm software to simulate future conditions to capture system operations at a more detailed level necessary to properly plan for a 100% renewable supply portfolio. Ascend's software models at the minute level, and employs stochastic programming to select the most robust resource plan to meet future needs.

Our analysis determines the optimal power supply resource mix. Ascend's PowerSimm software:

- Determines optimal expansion plan with consideration of costs, system reliability and flexibility, resource adequacy, and uncertainty of fuel prices, carbon, and meteorology impacting renewable generation and load.
- Provides a robust evaluation of the economic merits of combined-cycle (CC) units and internal combustion engines (ICEs) versus flexible storage for O‘ahu that captures the extrinsic value of each asset to provide flexible energy and ancillary services.
- Determines the value and need of flexible thermal generation, under conditions of perfect and imperfect foresight, in meeting future load in O‘ahu.
- Determines the change in costs and risks in costs for meeting PSIP portfolio emission constraints with and without LNG.
- Develops optimal unit retirements with consideration of costs, resource adequacy, and system flexibility needs.
- Develops a detailed economic evaluation of energy storage system relative to alternative supply from either fossil fuel or biomass resources.
- Evaluates the cost effectiveness of energy storage for regulating reserve and sub-hourly cycles using sub-hourly modeling.
- Determines regulation and contingent reserve requirements for each island served as a function of solar and wind.
- Determines the cost tradeoff between renewable curtailment and alternative actions of either cycling thermal generation or utilizing storage.

Ascend Analytics is a leading energy analytics software company that serves as the analytic infrastructure supporting portfolio management and planning decisions for a host of national utilities. Ascend provides analytic solutions that systematically capture and incorporate uncertainty into the decision making process. In addition, Ascend models physical system operations in greater detail than other production cost modeling and planning software. In 2014, Ascend supported the nearly $1 billion acquisition of renewable hydro generation in a resource plan for NorthWestern Energy in Montana. The resource plan proceedings were conducted in the Montana Supreme Court Chambers with Ascend testifying and receiving the distinction of modeling "fully consistent with industry best practices" by the independent experts retained by the Commission to review Ascend's modeling.

PowerSimm Planner

Ascend Analytics completed analysis in 2015 that valued for Hawaiian Electric the conversion of its oil based generation fleet to LNG. Through this PowerSimm modeling analysis, Ascend proved the value of a structured framework that models uncertainty in key risk drivers including: weather, load, renewable generation, renewable penetration rates, and market fuel prices and carbon. Ascend leverages these modeling capabilities of uncertainty combined with a more granular physical representation of Hawaiian Electric's power supply system at the minutely level. In addition, Ascend expands upon the detailed modeling of minutely level system operations to determine the optimal power supply resource mix inclusive of uncertainty. The use of minutely dispatch operations also supports evaluation of system capabilities to meet dynamic ramps and maintain system frequency.

Ascend brings the unique capability to model system operations in greater physical detail over a broad spectrum of future operating conditions at a granular level of minutely dispatch. In addition, Ascend's capacity expansion logic integrates the more granular system modeling and uncertainty to pick the most robust supply plan to meet the Companies' future needs over a broad spectrum of future simulated meteorological conditions and market prices.

Ascend has found that while deterministic runs with sensitivities provide insight into portfolio management decisions, the limited set of information of deterministic runs compared to probabilistically enveloping future states through Monte Carlo simulations can bias results. Furthermore, simulating future conditions with "meaningful uncertainty" can better articulate dimensions of risks for each of the future supply portfolios.

PowerSimm Planner's capacity expansion module determines optimal future supply portfolios by selecting the best supply portfolio over all simulated future conditions. This is a substantial improvement over other solutions that are limited to picking the best portfolio over a single deterministic run (and often with only load duration curve granularity). By determining the best portfolio over all future states, PowerSimm provides a more robust future supply portfolio.

Description of PowerSimm Planner

PowerSimm Planner provides optimal resource planning analysis that combines detailed system operations, including minutely level dispatch modeling, with simulations of the principal risk factors determining physical and financial uncertainty. PowerSimm Planner directly incorporates risk into to the resource selection process by finding the optimal expansion plan over a broad set of future simulated conditions to jointly minimize costs and risks. The selected optimal resource expansion plans provide distributions of costs where risk can be monetized as a direct cost; thus, enabling uncertainty to be valued in direct comparison of alternative expansion plans.

Underlying the risk based decision analysis framework of PowerSimm Planner are simulations of future conditions that rigorously realize the standard of "meaningful uncertainty". The realization of physical uncertainty begins with weather and then the resultant load and renewable generation levels. Financial uncertainty extends to commodity prices for fuel following market expectations of future prices uncertainty including episodic high and low price events. Carbon is also simulated based on ranges in forecast expectations of carbon prices.

System operations are measured down to minutely level generation and load with determination of ancillary service components of regulating reserves and contingent reserves as a function of renewable generation levels. The more granular dispatch conditions enable the physical system modeling to reflect actual system operations chronologically through time.

Recognizing the computational burden of the simulations, dispatch, and summary of results, Ascend utilizes a parallel distributed computing system: "The Ascend Cloud". This bank of computers supports resource planning analysis without compromising the modeling. The model inputs and outputs can be readily accessed through the Ascend Cloud.

PowerSimm Resource Selection

PowerSimm Planner performs optimal capacity expansion planning to determine the least cost and least risk resource options to meet future load. The optimal expansion plan analysis determines the least cost resource mix to meet a target reserve margin to maintain system reliability. Because utility planning involves a trade-off between long-term capital investment decisions and variable operating costs, the optimal expansion plan seeks to minimize the net present value (NPV) of future variable and fixed costs. To account for capital investment decisions not fully amortized over the 30 year planning horizon, the levelized cost for future resource options are used.

The expansion planning problem can be more formally stated as:

Minimize:	Portfolio costs = net PV power cost + fixed PV cost
Subject to:	Resource adequacy requirements
	RPS standards
	Regulation and contingent reserve requirements
	Thermal generation operating characteristics
	Battery storage operating characteristics and life cycles
Where:	Costs = net power costs + fixed costs
	Net power costs = fuel + variable O&M + emissions
	Fixed costs = fixed revenue requirement of portfolio in each year calculated from the financial model

The addition of new generation resources follows from both the requirement to ensure reliable generation supply and the economics of new generation.

While using deterministic runs with sensitivities provides insight into portfolio management decisions, this limited set of information biases results. This bias is not observed when realized through probabilistically enveloping future states through Monte Carlo simulations. Furthermore, simulating future conditions with "meaningful uncertainty" better articulates some dimensions of risks for each of the proposed portfolios.

The use of Monte Carlo simulations can be combined with the Resource Selection module of PowerSimm Planner to systematize the resource selection process. PowerSimm's Resource Selection module automates the resource selection process of determining the optimal future supply portfolios. The methodology provides the best supply portfolio overall based on simulated future conditions. The ability to select the optimal portfolio over a broad spectrum of future conditions without loss of generation modeling details provides substantial advantages over picking the best portfolio from a single deterministic run. The optimization of future supply portfolio utilizes a stochastic dynamic program to minimize the net present value of costs over all simulations subject to a series of constraints, most notably, capacity. By determining the best portfolio overall future states, PowerSimm provides a more robust future supply portfolio.

By incorporating uncertainty into the expansion planning process, this analysis builds upon the concept of risk and simulations that produce "meaningful uncertainty". The challenge of incorporating uncertainty into capacity expansion planning is further met by the need to address the value of resource flexibility. The modeling requirements to account for resource flexibility require hourly simulations and modeling asset start-up and shut down costs and times and generation ramp rates. More flexible resources can quickly and cost effectively cycle—a core asset attribute to support the addition of more renewable generation. The addition of uncertainty and detailed hourly generation characteristics distinguishes the rigor of capacity expansion planning used in this analysis.

Stochastic Dynamic Programming for Resource Selection

Ascend defines the value function as:

$$V_t(1_{it}, \dots 1_{Nt}) = \mathrm{E}[\textstyle\sum_{j=t}^{T} \sum_{i=1}^{N} \beta t * \ Total\ Costs_{jt} \ * 1(optimal)_{ji}]$$

$1(optimal)$ are the optimal asset choices (build or don't build) for time j, j = t, …, T so the value function is the expected minimum cost for the expansion planning problem.

Dynamic programming turns the multi-period problem into a two-period problem via an equivalent, recursive definition of the value function:

$$V_t(1_{i,t}, \dots 1_{N,t}) = \min\left\{\sum_{i=1}^{N} Total\ Costs_{i,t+1} 1_{i,t+1}\right\} + \beta E[V_{t+1}(1_{i,t+1}, \dots 1_{N,t+1})]$$

Where the minimization is over $1_{i,+1}$, … $1_{N,t+1}$, the portfolio of assets that will be online in period t+1. State vector is ($1_{,}$, … $1_{N,t}$).

To handle (1), the value function is iteratively solved for using a backwards recursion:

- Find all the asset mixes that satisfy the constraints as of month "T": for each of these, calculate the NPV of costs associated with the asset mix.
- Find all the asset mixes that satisfy the constraints as of the previous period (month T–1).
- Find all the asset construction plans that get you from a feasible asset mix in month T–1 to a feasible asset mixes from month T:
  - For each of these construction plans, calculate the NPV of the costs (that is, the cost associated with each construction opportunity plus the NPV for the asset mix from the month-N asset mix that the construction will result in).
  - Note that for each feasible asset mix in month N-1, you need only track the construction opportunity that has the lowest NPV
- Repeat, stepping from T–1 back to T–2, then back to T–3, and so on until arriving at month 0.
- The end of this backwards recursion results in the expression for $V_t(1_{i,t}$, … $1_{N,t})$ for all t, thus easily solving for the minimum cost portfolio given an arbitrary initial state for any t in (1, …, T).

We can use to calculate the expectation part of the second component in Bellman's equation: [($1_{i,+1}$, … $1_{N,t+1}$)].

Using simulations when no closed form exists for the transition probabilities is one of the major advances in the field of Approximate Dynamic Programming.

For the Policy functions used in stochastic dynamic programming we have:

$$V_t(1_{i,t}, \dots 1_{N,t}) = \min\left\{\sum_{i=1}^{N} Total\ Costs_{i,t+1} 1_{i,t+1}\right\} + \beta E\left[V_{t+1}(1_{i,t+1}, \dots 1_{N,t+1})\right]$$

Where the minimization is over $1_{i,+1}, \dots 1_{N,t+1}$, the portfolio of assets that will be online in period t+1. State vector is $(1_{,}, \dots 1_{N,t})$.

Policy functions are the solutions to the previous minimization as functions of the state.

$$1^*_{i,t+1} = f_{i,t+1}(1_{i,t}, \dots 1_{N,t})$$

$$1^*_{N,t+1} = f_{N,t+1}(1_{i,t}, \dots 1_{N,t})$$

Optimized expansion paths are simulated by the policy function markov chain.

Stated in less technical terms:

The Minimum Expected Value of Total Cost:

$$\text{E[NPV of Total Costs]} = \text{E}\left[\sum_{t=1}^{T}\sum_{i=1}^{N} \beta t * Total\ Costs_{it} * 1_{it}\right]$$

Fixed Costs follow revenue requirements: depreciation, amortization, current taxes, deferred taxes, insurance, property taxes, on-going capital improvements, and return on equity and debt.

Variable Operating Costs come from hourly dispatch aggregated up to monthly totals including: start-up costs, minimum uptime and minimum downtime constraints, emissions and variable heat rates.

Subject To:

Reserve Margin Constraints:

$$\sum_{i=1}^{N} Capacity_{it} \geq \gamma PeakLoad_t\ for\ t = 1\ to\ T$$

where γ is the required reserve margin.

Energy Constraint:

$$\sum_{i=1}^{N} Energy_{it} \geq Load_t \; for \; t = 1 \; to \; T$$

Renewable Constraint:

$$\sum_{i=1}^{N} Renewables_{it} \geq RPS_t \; \; for \; t = 1 \; to \; T$$

Ancillary Service Requirements:

$$\sum_{i=1}^{N} Regulation_{it} \geq `Reg\ Limitt \; \; for \; t = 1 \; to \; T$$

$$\sum_{i=1}^{N} Spin\ Res_{it} \geq Spin\ Limit_t$$

$$\sum_{i=1}^{N} NonSpin\ Res_{it} \geq NonSpin\ Req$$

$$\sum_{i=1}^{N} Flex\ Ramp_{it} \geq Flex\ Ramp\ Req$$

PowerSimm System Flexibility Software

The objective of the PowerSimm module, System Flexibility Software, is to determine the amount of flexible generation capacity required when planning to integrate intermittent renewable energy sources into an energy system. Flexibility requirements are estimated in terms of (1) regulation requirements necessary to maintain CPS2 scores at 95 and 99.9, (2) ramping requirements at both 15-minute and 1-hour time steps, 3) changes in ramping direction of net load, and 4) dump energy.

Because of the large proportion of solar generation, these requirements are estimated by daytime and nighttime requirements. The analysis determines flexible generation requirements by estimating the variability of historical minutely data for load and renewable generation.

The methodology of the PowerSimm System Flexibility Software is defined below.

Regulation

Regulation is the intra-hourly deviations from the linear interpolation through minute zero of net load. It is a zero-sum system balancing metric that represents the system's requirement for flexible generation capacity at the 1-minute level.

$$Regulation_t = NetLoad_t - NetLoadFollowing_t$$

$$NetLoad_t = Load_t - UtilityPV_t - CustomerPV_t - OnshoreWind_t - OffshoreWind_t$$

- Load and renewable data is assigned peak period labels for Day-Time and Night-Time. The daytime peak period is defined as the minutes of the day in Honolulu as recorded by the following website: http://www.timeanddate.com/sun/usa/honolulu.
- Net Load is calculated as load minus renewables.
- Net Load following is calculated as the linear interpolation of net load from the first minute to the last minute of each hour.
- Regulation is then calculated as the difference between net load and net load following (not counting minute zero).
- The regulation requirement is then calculated as the average of the absolute values of the upper and lower confidence bounds of regulation calculated separately for Day-Time and Night-Time as defined above.

Ramps

$$Ramp_{t,p} = Net\_Load_t - Net{-}Load_{t-p}$$

The 1-hour and 15-minute ramp statistics are calculated as the difference between the net-load at a given time (time t) and the net-load exactly 15 minutes and 1 hour prior to that time respectively (time t–p, where p is the time interval of 15 or 60 minutes). Physical ramps assume that load minus renewables can never be less than zero, since generators cannot ramp down less than zero. Physical and absolute ramps are calculated for each minutely data point at time t, where we have data for time t–p. The maximum 15-minute and 1-hour ramps up and ramps down for each year are reported both for the day-time and night-time.

Scaling

Historical minutely data is multiplicatively scaled to forecasted capacities by dividing by the historical max and multiplying by the forecasted capacity.

- Overlapping historical data for grid-scale solar PV, DG-PV, onshore wind, offshore wind, and load are each separately scaled so that the average is 1 MW.
- Load is scaled to the forecasted average MW, and renewables are scaled to their assumed capacity times the historical capacity factors by theme and year.

Forecasts for the selected theme can be viewed in the 'Selected Forecast' tab. Then adders for onshore wind, offshore wind, and grid-scale solar PV are applied to forecasts, and the same process is done to scale the renewable resource's generation to its new capacity.

Dump Energy

Dump energy is the must-take energy in excess of load, that is, the energy that should be curtailed or utilized for charging batteries.

$$Dump_t = Max\{0, MustRunThermal_t + RenewableGen_t - Load_t\}$$

- Minutely dump energy is summed by day.
- Daily dump energy is averaged by year.
- Average daily dump energy is converted from MWm to MWh.
- Dump-hours are calculated from minutely data as the average number of hours per day where the system is dumping more than 10% of load.

Minimum Thermal Generation Levels (labeled as 'mingen' in the software) are calculated as the minimum generation output from thermal generators that are considered must-run for the selected theme and year. For additional flexibility, dump energy is also calculated using minimum generation adders from 0–100 MW by 10 MW. Minimum Thermal Generation can be viewed by Year and Theme in the 'mingen' tab.

Dump Energy was also calculated similarly using hourly data (minute zero of each hour) to illustrate the difference in minutely and hourly calculations of dump energy.

Comparison with Traditional Capacity Expansion Models

PowerSimm Planner includes many features unavailable or limited in traditional capacity expansion models for a number of modeling areas.

Physical generation asset operating characteristics (such as heat rate curves, ramp rates, min-up, min-down, and others. Traditional capacity expansion models have no ability to capture asset operating characteristics other than plant capacity. Integrated models dispatch generation consistent with the full set of plant operating constraints. By overlooking the physical constraints of asset operations, these models introduce potential biases and inconsistencies when selecting intermediate and peaking resources by not modeling asset flexibility.

Chronological relationship of load. Traditional capacity expansion models use load duration curves, which removes the hourly and daily pattern of load.

Chronological relationship to market prices. Traditional capacity expansion models use of price duration curves removes the hourly and daily pattern of market prices. Moreover, the structural relationship between system load and market prices are not maintained.

Imports and exports. Both models account for imports and exports, but the inability of traditional capacity expansion models to capture physical asset details introduces resource selection biases and inconsistencies. For example, a peaking unit may be designated as having the ability to provide exports when the start-up and shut-down costs or minimum run-times may make an off-system sale uneconomic.

Ancillary services. Traditional capacity expansion models do not have the ability to model ancillary services.

Simulation Framework

PowerSimm develops realistic simulations of future conditions to probabilistically envelope the expected value and range of potential future cases. Figure C-10 depicts the framework to simulate physical and financial uncertainty. The simulation of future conditions is initiated with before-delivery simulations of forward/forecast prices, which then evolve to the final monthly price expiration. Weather simulations then drive renewable generation and load. Spot prices are simulated as a function of load, renewable generation, and other potential variables of supply.

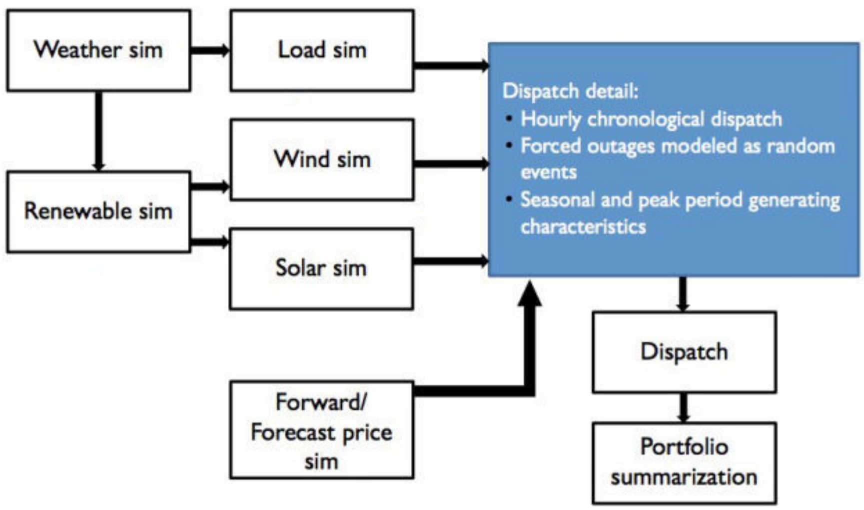


Figure C-10. PowerSimm Process Flow Diagram

The simulation framework of PowerSimm addresses uncertainty as viewed through today's market expectations (forward/forecast prices) and the future realized delivery conditions for load, spot prices, and generation.

Simulation of Commodity Prices and Physical Components

Simulation of electric system and customer loads follows from a common analytical structure that seeks to preserve the fundamental relationship between demand and price. The simulation process is divided into two separate components: before delivery and during delivery. The before-delivery simulation of forward/forecast prices evolves current expectations through time from the start date to the end of the simulation horizon. The simulations during delivery capture the relationship of physical system conditions (that is, weather, load, wind, solar, unit outages, and when applicable transmission). The inter-relationship between before-delivery and during-delivery simulations is central to linking expectations to realized observations.

For forward/forecast prices representing before-delivery simulations, monthly prices are evolved into the future from the current forward/forecast prices through expiration of each contract or forecast month. This process of evolving forward/forecast prices into the future draws on the observed behavior of forward contract variability and covariate relationships to create future monthly price projections. Within each before-delivery simulation, observed commodity prices behavior, volatility, rate of reversion, and covariate relationships across commodities drive price movements to ultimately arrive at a final evolved price at delivery. The average of these final evolved prices across all simulations for each monthly price equals the current forecast expectation of the price at delivery. Similarly, the average of the simulated electric spot prices for a given month equals the current forecast price for that month. Seasonal hydro conditions are also correlated with the simulated forward/forecast prices.

The during-delivery simulation process begins with simulation of weather. PowerSimm simulates weather using a cascading vector auto-regression approach across multiple locations. This approach maintains both the temporal and spatial correlations of weather patterns for the region. Ascend applies a cascading vector auto-regression approach to maintain inter-month temperature correlations consistent with the historical data. For example, if a hot July day is likely to be followed by another hot July day, the cascading vector auto-regression method captures this effect. The application of weather simulations supports the analysis of uncertainty through hundreds of weather cases without the limitation of the pure historical record where extreme weather events beyond observed conditions may occur (but with a low probability). The second step of the process combines these weather simulations with other factors in the load simulation process.

Load and Price Simulation

PowerSimm uses the weather simulations as well as forecasted input load values, scaling and shaping the simulated load shapes to match forecasted monthly demand and peak demand values. The simulations of electric load use a state-space modeling framework to estimate seasonal patterns, daily and hourly time series patterns, and the impact of weather. The state-space framework of PowerSimm produces results that reflect the explained effects of weather and time-series patterns and the unexplained components of uncertainty.

The during-delivery simulation of prices addresses the more intuitive simulations of system conditions and spot prices. System conditions of unit outages, supply stack composition, system imports and exports, and transmission outages are separated independent of weather but can also serve as determinants to the spot price of electricity.

PLEXOS FOR POWER SYSTEMS

PLEXOS® provides a platform for economic analyses of energy systems that co-optimizes the contributions from energy, ancillary services, fuels, emissions, water resources, and transmission systems from sub-hourly chronological scheduling to analyze long-term planning. The model datasets for the islands are developed from reference case assumptions provided by the Companies. PLEXOS provides detailed modeling of the generation resources, including thermal, wind, solar PV, battery storage, demand response, distributed energy resources, hydroelectric, and pumped-storage hydro in these data sets. PLEXOS provides output from the island data sets for benchmarking with existing models used by the Companies.

PLEXOS contributes data in capacity expansion plans for all five islands served combined with economic analyses of those expansion plans. The expansion plans are produced under several core cases.

The PLEXOS modeling approach implements its models as physical systems with economic and financial impacts. The model uses engineering inputs for generation resources, resulting in operational and financial outputs that depend on forecasts of market conditions (such as fuel prices and contract positions for the scarce resources that power the various assets). PLEXOS is reliable simulation software using state-of-the-art mathematical optimization combined with the latest data handling. Combined with visualization and distributed computing methods, the model provides a high-performance, robust simulation system for electric power that is leading edge, open, and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features seamlessly integrating electric, water, gas, and heat production, transportation and demand over simulated timeframes from minutes to decades. PLEXOS is one of the fastest, most sophisticated, most cost-effective software available for performing the analyses required to develop the 2016 updated PSIPs.

PLEXOS is reliable simulation software that uses state-of-the-art mathematical optimization, combined with the latest data handling, visualization, and distributed computing methods, to provide a high-performance, robust simulation system for electric power, water and gas. Its processing is open and transparent. PLEXOS meets the demands of energy market participants, system planners, investors, regulators, consultants, and analysts with a comprehensive range of features. The model seamlessly integrates electric, water, gas, and heat production; transportation; and demand over simulated timeframes from minutes to decades—all delivered through a common simulation engine with easy-to-use interface and integrated data platform.

Energy Exemplar developed PLEXOS datasets to model generation resources for O‘ahu, Hawai‘i Island, and Maui for our April 2016 updated PSIP. We developed PLEXOS datasets to model generation resources on Moloka‘i and Lana‘i.

Unit commitment and economic dispatch to evaluate the economics of the generation system was modeling for all five islands. Capacity expansion modeling for portfolio optimization and RPS modeling was run for Moloka‘i and Lana‘i.

The analysis includes evaluating DR programs, existing economic fleet retirement, expansion to satisfy RPS targets (including renewable and traditional resources), expansion, and economic modeling of battery storage devices. This tool also develops sub-hourly models to capture the benefits conveyed by flexible resources, especially in a resource mix that includes high variable renewable penetration.

ADAPTIVE PLANNING FOR PRODUCTION SIMULATION

Black & Veatch is applying its Adaptive Planning for Production Simulation (AP) model to support the 2016 updated PSIP analysis. AP provides a framework for modeling complex systems, exploring options (impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes associated with this analysis include costs, degree of renewable penetration (both capacity and energy served), utilization of demand response and distributed energy resources, avoided costs associated with demand response, and metrics associated with generation-related grid security.

The AP model incorporates Demand Response (DR), Distributed Energy Resources (DER), and grid-scale renewable integration into its production runs.

AP is delivered through Black & Veatch's ASSET360™ platform, possessing state-of-the-art ability to evaluate technical asset performance, commitment, dispatch, and operations problems. ASSET360 and AP features cloud-based analytics and math engines and provides the ability to construct and explore wide range of cases and sensitivities. This capability was extended in concert with the Companies to also manage and evaluate interaction and valuing of DR products and program portfolios. This enables AP to model and compare very granular energy and grid services protocols and to identify optimal allocation of combined physical plus DR resources to provide a full range of services. ASSET360 builds upon over 20 years of complex modeling and simulation tools developed and implemented by Black & Veatch to evaluate alternative technology, fuel, maintenance, compliance, and operational strategies and develop actionable and implementable plans.

AP applies a sub-hourly analysis to model combinations of conventional power production and grid resources, variability of non-firm resource supply, storage, and energy and grid services protocols, all to identify the optimal allocation of combined physical plus DR resources to provide a full range of services. Sub-hourly analysis is required to fully understand and model impacts of variability of wind and solar, and to accurately assess the need for grid services and fit of a DR program portfolio in concert with physical assets to support those needs.

Black & Veatch possesses deep domain expertise in the technologies deployed—from design, operations, and reliability perspectives—as well as deep domain expertise in complex simulation. This combination provides critical thinking and credibility needed in addressing very complex and costly investment decisions across PSIP areas of interest. Given the desire and need for massive transformation, the underlying model must be very technically robust to assure that all transformative steps are both rational and fully understood. Key aspects that can be specifically addressed include technology selection and implementation, plant refurbish and upgrades, retirements, DER build out, and participation and structure of DR programs.

Black & Veatch capabilities and reputation are critical for both credibility of the process and model as well as credibility of the results, given that the interactions between conventional power production, renewable resources, storage, and customers are very complex, and given that Hawai'i is clearly on the cutting edge of such strategy development. Black & Veatch possesses the ability to leverage proven analytics framework within the context of the 2016 updated PSIPs, to provide high-level of modeling expertise to build and refine PSIP cases, and the ability to help define and manage complex processes needed to align asset portfolio, security requirements, DER uptake assumptions, and DR portfolio implementation and utilization. These capabilities are complementary to the larger PSIP team and are foundational to PSIP team's ability to deliver critical thinking and key results.

Exploration of options and collaboration between the Companies, Black & Veatch, and other consultants is also quite important to achieving quality results. Processes implemented for coordination across the modeling teams are, by necessity, complex and iterative; Black & Veatch possesses the fundamental capabilities needed to support these important activities. The ability of AP to leverage the cloud is also particularly valuable for PSIP where exploration across decision dimensions is needed. For example, automated processes can be leveraged to explore the solution space (that is, timing and volumes of DER resources, timing and volumes of grid-scale renewable and energy storage resources). This enables the PSIP team to see and illustrate value and strength of strategies and sensitivity of strategies to key underlying assumptions.

Configuration Methodology

AP manages the overall calculation and cost accounting process. PSIP-specific requirements are directly addressed by configuring the solution.

Thermal Generation

Firm thermal generation resources are modeled as having the ability to meet demand, up and down regulation, contingency, and frequency response (modeled as system inertia requirements based on system state). Assets are committed based on the combined minimum load operating, minimum load fuel, startup time, and associated startup costs. These assets are dispatched by AP's optimizer to achieve the lowest possible fuel and variable operating costs based on a given set of constraints.

Data required to support the commitment and dispatch of these resources include the following:

- Installation and deactivation and retirement dates
- Fuel, variable operating, startup, and startup fuel costs or generation-related PPA cost
- Fuel contract and supply constraints
- Fuel switch dates and fuel switch capital costs
- Heat rate curve and minimum and maximum loads
- Ramp rate, hot and cold start time, minimum up and down time limitations
- Scheduled outages or rate, forced outage rate
- Kinetic energy (as proxy for ability to provide inertial response)
- Operating limitations to meet transmission system security requirements
- PPA obligations
- Unit operating constraints because of emission regulations or work shift requirements.

Additional information required to characterize the generating cost of each resource includes capital and fixed operating costs, including transmission-related costs.

Variable Generation

Future variable generation resources are modeled as having the ability to provide energy, down regulation via curtailment and up regulation while being curtailed. Energy produced by the variable resources is calculated using an hourly or sub-hourly profile constructed from historical data from in-service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this profile but cannot be accommodated on the system is curtailed per a specified curtailment order.

Data required to model the generation available from these resources and associated costs includes the following:

- Hourly or sub-hourly generation profile.
- Ability to be curtailed and curtailment order of the facility including curtailment costs.
- Energy contract costs for non-utility owned resources.
- Capital and fixed operating costs, including transmission-related costs.

Central Energy Storage

Grid-scale energy storage is applied as a resource to supply capacity, regulation, contingency, and other ancillary services associated with frequency response. Energy storage added to supply capacity, regulation, or contingency is modeled via the dispatch model. Energy storage added to manage frequency response supplements the commitment of firm resources and other resources that also provide frequency response.

Data required to model the usage of these resources and associated costs includes the following:

- Size, capacity, and efficiency.
- Usage schedules or rules.
- Operating restrictions.

Distributed Energy Resources

Distributed energy (such as DG-PV or customer-owned batteries) is integrated into AP in a method very similar to the treatment of grid-scale storage and grid-scale PV. DER generation is developed following an hourly profile and is treated as a reduction in sales and demand. Some DERs are able to be curtailed and this functionality is also modeled.

Data required to model the generation available from distributed energy resources and associated costs includes the following:

- Hourly generation profile.
- Ability to be curtailed and curtailment order of the resources including curtailment costs.
- Contract costs (for example, Feed-in Tariffs-FIT).
- Battery size, capacity, and efficiency.
- Battery usage schedules or rules.

Demand Response

Demand response can be evaluated in two ways.

A known DR portfolio is factored into AP as a change in overall demand curve as influenced by time-of-day pricing and an ability to provide ancillary services (up and down regulation, contingency, and frequency response). Data required includes the following:

- Hourly load modification projections by product.
- Hourly ancillary services projections.
- Program fixed and incentive costs.

The available DR products can be evaluated individually and in combination to identify the optimum portfolio mix. In this situation, products are fit together to either afford ability to substitute for physical resources; or provide economically superior response mechanism to address load dynamics or unexpected contingency events. Information required for each of the products includes magnitude of service, cost of DR to provide each service, attributes of each service, and identified opportunities for combinations of services:

- Purpose (capacity, peak shaving, ramp avoidance)
- Availability (MW, time)

- Characteristics (ramp rate, response speed, accuracy)
- Response after curtailment (snap back MW and duration)
- Limitations (event duration, frequency)
- Costs to provide the service (fixed, per event, per kW called)

Finally, the value of individual products year to year can be significantly different as the system is in a state of flux with the addition and retirement of grid-scale resources, the continuous addition of consumer energy storage systems, and evolving loads (electric vehicle loads for example) all contributing to make each year's demand response value proposition unique. Thus, the makeup of the DR portfolio can be expected to vary over time.

System Security

Given the interest in identifying if and when DR products could substitute for physical resources to help meet primary frequency response (for example, fast frequency response-FFR), the ability to understand implications of the security protocols on service requirements is a key issue. To this end, Black & Veatch incorporated, as an option, a regression model based on inertia and kinetic energy from electric generators to better relate needs to optional portfolio and service combinations into AP. The resulting regression becomes a commitment requirement.

Regression equations were developed for O‘ahu to understand the additional response requirements for 2018 forward. The regression simulated Hawaiian Electric Transmission Planning results for the response requirements based on the system state each hour. Twelve-cycle data was used in the regression analysis. The regression model enabled the overall requirements to be met either via application of physical resources or via combination of physical resources and DR products.

The following are typical of types of assumptions that support the security analysis:

- The largest contingency was based on largest single generating unit trip (while AES is operational, 180 MW) with a concurrent 59.3 Hz Legacy PV trip (55 MW).
- Allowable load shed for 2016 and 2017 based on present day reliability.
- When the contingency energy storage is in service, allowable load shed is eliminated.
- FFR modeled as step MW injection before a minus 12 cycle time delay from time of disturbance.
- MW requirement is based on reliability, which is driven by the contingency and the load shed scheme.

Time Slice Model within AP

At the heart of AP is a direct solution engine within a time slice model that enables a direct aggregate match of resources to demand and security requirements. Within AP, each time slice affords the opportunity to accomplish the following:

- Introduce new resources, retire resources, or change asset characteristics (simulate planned and forced outages, fuel switch, reduce minimum load).
- Introduce DR products (quantity by product, maximum calls, maximum duration).
- Incorporate assumptions for wind and solar variability based on perturbations of historical wind and solar patterns.
- Incorporate rules for utilizing distributed generation as a must-take and/or curtailable resource.
- Commit resources and schedule DR products based on asset availability, grid security, policy constraints, and economics.
- Dispatch resources or call DR products based on grid security protocols and economics including use of demand response and energy storage to address ramping or smoothing, and forced outages of committed resources.
- Identify boundary conditions (from time slice to time slice) that serve as the basis for evaluating the next time slice; certain actions, such as starting a thermal generator within a particular time slice, would require forward commitment across time slices.

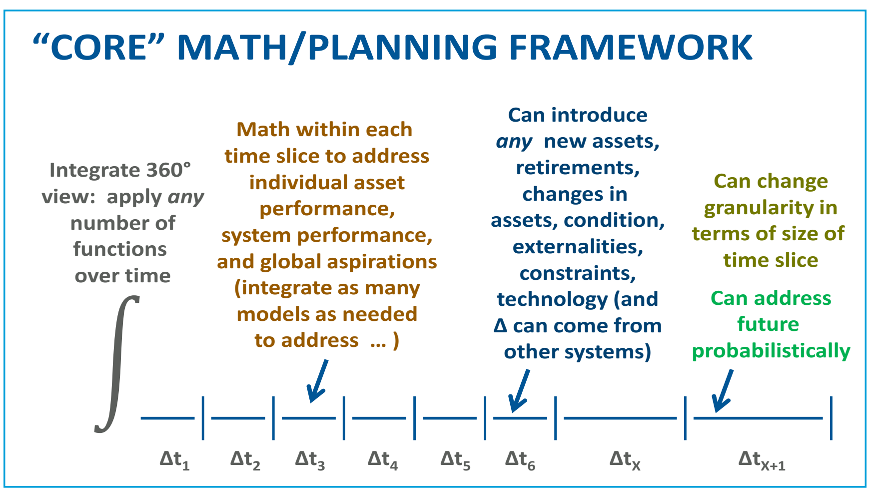


Figure C-11. Adaptive Planning Core Math and Planning Framework

The simulation engine works in conjunction with the commitment and dispatch algorithms to evaluate the situation in the current period and translate this information to subsequent affected time slices. Each time slice considers (takes as input) the following for each power source:

- Status (available, scheduled outage, forced outage, retired).

- Operating efficiency and minimum load.
- Maximum load (as limited by solar or wind penetration forecast, as applicable).
- Fuel characteristics and costs (if applicable).
- Startup costs and fuel requirements (if applicable).
- Variable operating costs or power purchase agreement costs.
- Ramp rates, minimum downtime, and minimum uptime.
- Fixed operating and capital costs.

Each time slice also considers demand adjusted for demand response load shaping programs. With this information, the time slice model determines the following for each power source:

- Status applicable to next time slice
- Generation
- Contribution to regulating requirements and other grid services
- Consumable requirements
- Operating costs

Commitment and Dispatch Methodology

AP addresses commitment requirements on an hourly basis and dispatch on either hourly or sub-hourly increments. For example, five-minute increments are applied for assessing a regulating reserves DR program where the dynamics of wind and solar loading are being matched with DR or firm asset services for regulation.

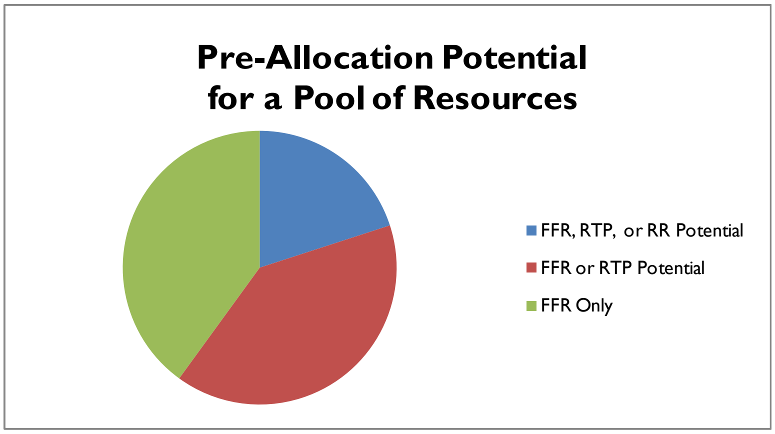
When determining commitment (units that are online), the model endeavors to meet both demand (incorporating load-shift demand response) and grid security requirements. It starts up or shuts down generating resources as needed to meet these requirements. It prioritizes the resources online to include units required to support system security, to meet goals such as maximizing renewable resource use, and to meet the requirements of power purchase agreements. The load shifting battery charge and discharge cycle is optimized for each day based on load net of wind and solar generation and DR load shift.

Once commitment is set, the model considers dispatch. If dispatch needs to increase to meet demand, the model first considers preferential dispatch targets such as eliminating curtailment of renewable resources. Next, regulating reserve batteries, if available, are dispatched to their target. Finally, load is increased at dispatchable units based on economics. If dispatch needs to decrease to match demand, dispatchable units are economically backed down, regulating reserve batteries are charged to maximum capacity to minimize curtailment and, as last resort, non-firm renewable resources are curtailed.

Demand Response Methodology

Specific modeling techniques to evaluate the range of services provided by DR were developed based on the characteristics of each service. Services are segmented into two categories: fast (defined as a service to address a transient issue) and slow (defined as a service to manage system demand and supply equilibrium). Fast services are characterized by defined constraints (for example, required regulating reserves), modeling of security requirement proxies (for example, use of kinetic energy as proxy for addressing FFR requirements), and inclusion of incremental costs (for example, application of battery to supply contingency requirements). DR products are then evaluated for their ability to compete against other resources to provide each service.

When combining the potential of individual DR products into a portfolio, it must be recognized that each end-use device is limited in its ability to provide multiple services at a time. Typically, an end device can provide one load building and one load reduction service simultaneously. For example, a water heater participating in a pricing program that builds load during midday to take advantage of solar generation can at the same time provide FFR—a reduction in load in response to a sudden loss of a generating asset. It cannot provide FFR during evening hours when the water heater is reducing load under the pricing program, as this would constitute providing two load reducing services simultaneously. Similarly, a water heater cannot simultaneously provide both FFR and regulating reserve because, once turned off to provide one service, there is no potential available to provide the other service. As such, the DR potential for each product must be managed to prevent over allocation of end-use devices.



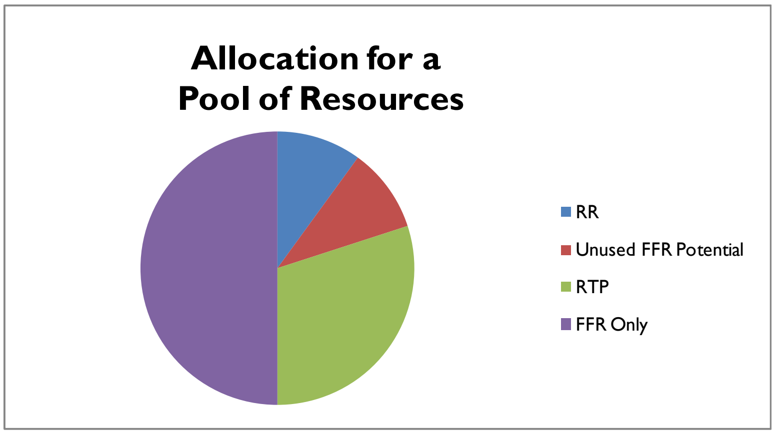


Figure C-12. Sample Resource Allocation

AP maps end-use devices to DR products to ensure the full range of services are evaluated while ensuring no double allocation of services. These mapping rules are:

1. Pricing programs (TOU, DALS, and RTP) are mutually exclusive: a single end device can only participate in one Pricing Program.
2. An end device cannot provide FFR at the same time as RR.
3. End devices participating in pricing programs can provide FFR or RR while building load.
4. End devices participating in pricing programs cannot provide FFR or RR while decreasing load.

The DR end-use allocation is based on the best value derived from the end-use device. Since both the DR potential (air conditioner load is higher in the summer and peaks during midday) and the needs of the generation and transmission system are dynamic by hour, DR potential is allocated for each hour. The allocation is complex as some system constraints are dynamic. For example, the system security requirement that sets the FFR need is based on the unit commitment, which is determined by the allocation of DR end-use devices for regulating reserves and load shifting. Given the finite DR potential, the optimal allocation often requires the layering of the constraints such that all constraints are satisfied and the DR potential is not over allocated.

Order and priority between underlying resources are managed as follows:

1. Pricing products shift load to desirable times and thus support capacity needs.
2. FFR is given next priority for potential.
3. Regulating reserve meets up-regulation.
4. Aggregated DR calls are checked against aggregated limits (number of calls per year, length of call) to ensure usage is within limits.
5. Products that meet specific needs other than those listed above, such as PV curtailment and minimum load, were not shown, in prior evaluations, to be cost-effective. Thus, these products are evaluated external to the simulation process to quantify their contribution to the generation system and can be incorporated into the simulation process when cost-effective.

The load shift (described in priority and order 1) is evaluated as an outer loop to the simulation model to optimize between pricing and incentive products. Potential associated with pricing products is allocated in a manner consistent with the anticipated price signal flexibility. Potential associated with products under a tiered rate schedule is allocated approximately as required by the generation system, but is constant for each hour within a tier. Potential associated with pricing products set via a forward-looking, hourly pricing scheme is tailored hour-by-hour and therefore more closely matches the requirement of the generation system. The load shift is MWh neutral on a daily basis; the increase and decrease each day does not change the overall demand associated with that day.

Tradeoffs between pricing products and incentive programs are evaluated for distinct levels of pricing products taken (0%, 50%, 100%). When less than 100% of the pricing product is used for load shift, the remainder of the end product's potential is made available (where there is overlap) for FFR and RR.

Each level of participation is compared for each day; the case with the lowest generation cost defines the percent of pricing product taken for that day.

The pricing products may reduce or postpone new generation as pricing programs shift loads and thereby reduce the annual peak. This reduces the need for new units to meet the reserve margin requirements.

Sub-Hourly Model

Traditional hourly modeling does not expose the operational transients that must be managed during real-time operation of the electric grid. Traditional hourly modeling also does not expose potential value (economic and risk mitigation value, for example) that one set of resources may have over another set of resources, as all transients are softened. Sub-hourly modeling exposes some of this value to support the optimum resource selection that does not violate policy considerations (risk tolerance, renewable goals, budget constraints, fuel diversity)

Similar to an hourly modeling approach, the sub-hourly model calculates both commitment (which units are generating power) and dispatch (MW contributed by each asset to achieve the target demand), but now at a sub-hourly time step. Maximum daily rate of change is greater and ramp rate constraints are hit more often, thereby potentially changing the economic outcome of the simulation as compared to the hourly model.

The sub-hourly model (five-minute time step) performs a constrained optimization for asset dispatch against a sub-hourly desired load. The resources considered include generation (dispatchable and non-dispatchable), demand response, and energy storage. Each asset has two primary states: available or unavailable. Each unavailable state may have sub-states (for example, scheduled versus unscheduled outages). There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options).
- Grid stability requirements, either must-run units or verification that adequate inertia is present on the system given system conditions.
- Policy constraints (power quality, reliability targets, risk tolerance).

The sub-hourly model changes the state of each asset to optimize the economics within the bounds of the model constraints. Accounting routines keep track of asset performance ($, MWh, number of starts) and system performance (unserved load, curtailed generation, $, MWh).

This modeling approach is ideally suited to evaluating, comparing, and contrasting differing strategies regarding the mix of fossil generation, utility renewables versus energy storage, distributed generation versus energy storage, and demand response options. Based on the supply options provided, the model determines the low-cost means for meeting the required load within constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration).

Loss of Load Probability (LOLP) Modeling

Black & Veatch uses a proprietary LOLP model (AP for LOLP) to calculate reliability measures for generation-demand systems. The LOLP model is a component of the Black & Veatch Adaptive Planning suite and is based on a Monte Carlo simulation approach. The model uses the same input format as the Adaptive Planning for Production Simulation model.

The reliability measures that AP for LOLP calculates are:

- Loss of load probability (LOLP)
- Loss of load expectation (LOLE)
- Unserved energy

LOLP is the probability that capacity cannot meet load and as such LOLP is a probabilistic measure. LOLP is stated in days per year. The LOLP does not measure the duration of the inability to serve load. It only measures the number of times (number of days) that load cannot be served. For instance, from an LOLP standpoint, not being able to serve load for four consecutive hours is no worse than not being able to serve load for one. LOLE is the hour by hour accumulation of the probability that hourly demand exceeds system capacity. Unserved energy is the hour by hour accumulations of the probability that hourly demand exceeds system capacity multiplied by the capacity shortfall. These reliability measures can be calculated for multiple years, taking into account maintenance scheduling, forced outages, and generation unit commissioning and retirements.

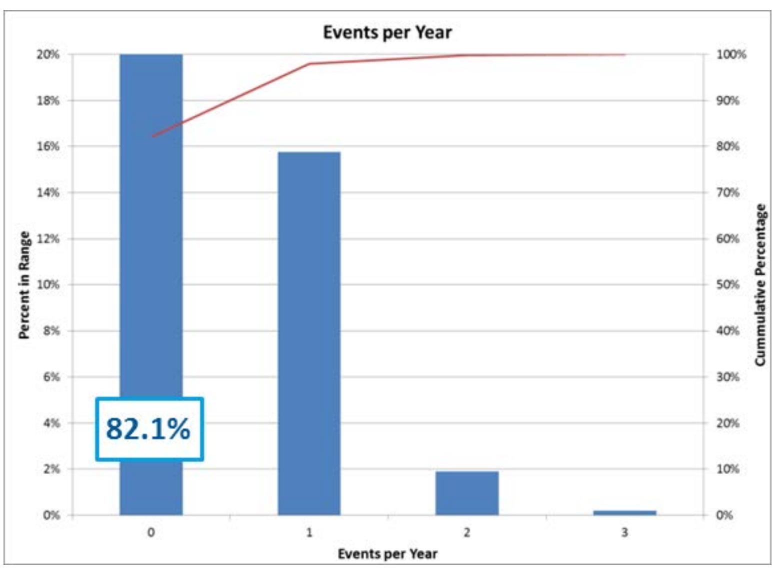


Figure C-13. AP for LOLP Predicts One Failure Event in Five Years

AP for LOLP considers the ability of firm generation, non-firm generation, demand response, and utility load shifting batteries to meet capacity needs. It uses a Monte Carlo simulation solution methodology. For this analysis, the Monte Carlo model evaluates the ability to meet load each hour of each year with many (currently 5,000) simulations evaluated for each year. For each of the 5,000 simulations, key variables that affect LOLP are allowed to vary.

These are:

- Demand
- Capacity of non-firm assets
- DR load shift potential
- Asset forced outages

Demand, capacity of non-firm assets, and DR load shift potential are randomized using the same methodology. LOLP begins with a profile that defines demand (or capacity or DR potential) for each hour of each year. For each simulation, the demand (or capacity or DR potential) in each hour is randomized by selecting a value for that same hour that occurs within the window of 21 days before and 21 days after the day in question. An example depicting the capacity of non-firm assets is provided in Figures 3 and 4. In hour 12, non-firm resources (wind, central solar, and distributed solar) are predicted to generate 1,110 MW (Figure 3). However, within the +/- 21 day window, the generation could be as high as 1,150 MW or as low as 375 MW (Figure C-18).

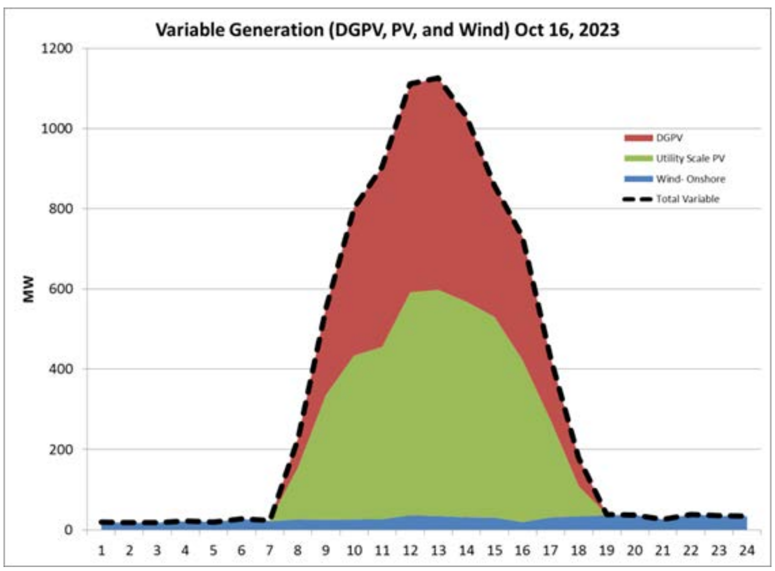


Figure C-14. Variable Renewable Generation Projection for October 16, 2023

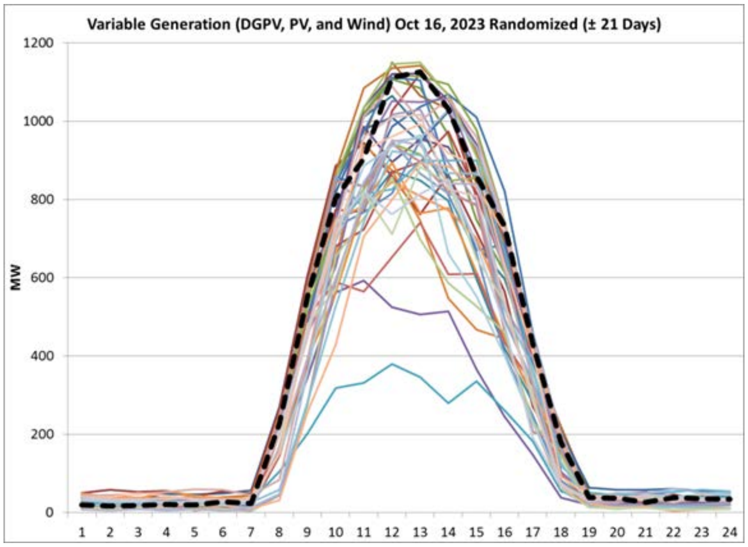


Figure C-15. Randomized Generation Projections for October 16, 2023

Asset forced outages are randomly assigned based on the forced outage rate data provided.

Model Outputs and Visualization Tools

AP output is generally organized into views of differing granularity according to the following:

- *Periodic Values:* This can be period to period (five-minute, hourly, daily, or annual) and consists of period inputs (assets available, state, demand), production factors (individual asset production or utilization in support of grid services), consumables (fuel, chemicals), and other variable O&M costs.
- *Average Day:* This view aggregates and averages all period values into a single day "view" by year, showing system behavior, unit participation and ramping, and provision of services during peak and off-peak periods.
- *Specific Day:* Similar to Average Day, this view provides the same outputs but for a specific day or range of days, showing the variability of system resources from day-to-day and year-to-year. This view is particularly valuable in understanding the variability in the value of grid services and optimizing DR portfolio.

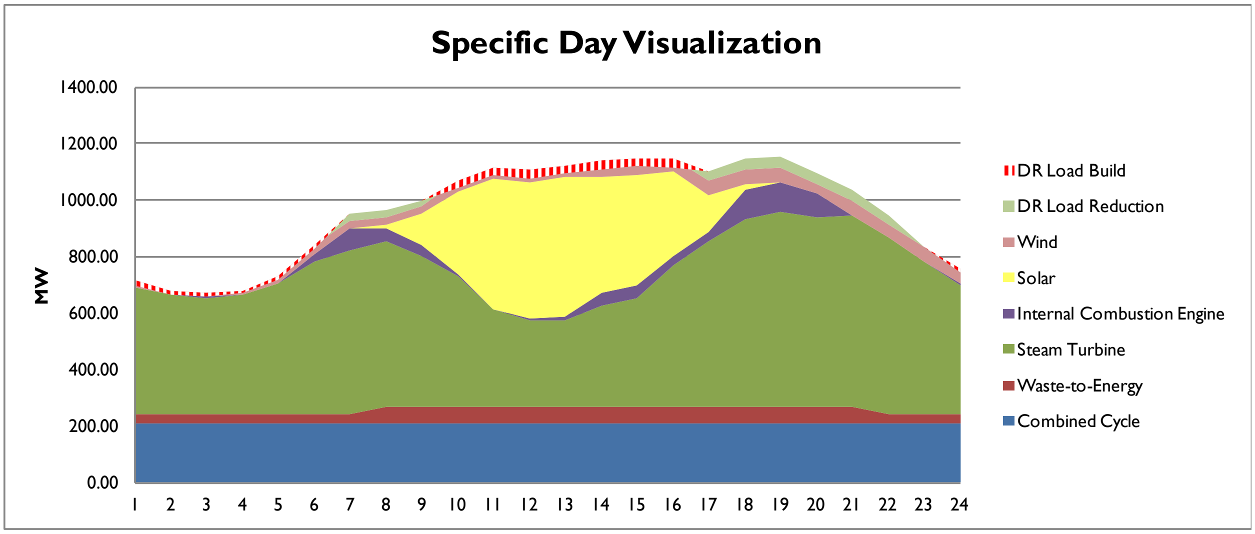


Figure C-16. Specific Day Results Example

- *Aggregations by Resource Type:* All views are available either by individual asset, DR program, or aggregated by type of asset. This shows how different asset classes are utilized in matching demand or providing grid services.
- *Comparisons:* Comparison views are applied against two cases to identify differences in outcomes, year-to-year or period-to-period.
- *Avoided Costs:* Avoided cost views are generated by mathematically "subtracting" an underlying base or reference case from the subject case. In particular, grid service values (or value of DR program) are based on mathematically assessing differential system costs against differential resources available to provide the grid services.
- *Value of Service:* Value of Service views are Avoided cost views where the savings are divided by the amount of service provided. Value of service views describe how the value of a service changes with the amount and timing of service being examined.

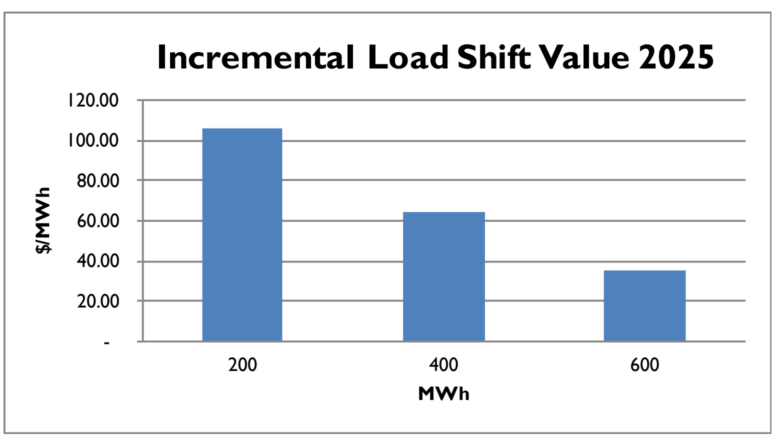


Figure C-17. Value of Service Results Example

DG-PV ADOPTION MODEL

The proprietary DG-PV Adoption Model (developed by the Boston Consulting Group) forecasts the adoption of customer-sited energy resources. The model primarily determines the quantity and installed capacity of DG-PV (with and without storage), together with the given retail or export rate when this adoption would occur. This model has been applied throughout the United States, Europe, and Australia with high levels of success. The model helps develop perspectives from a customer-centric approach regarding compensation levels, and resulting amounts and timing of customer-sited energy resources.

The model was used to forecast future quantities of self-supply, and potential future DG-PV combined with the possibility of the adoption of customer-sited storage.

The DG-PV Adoption Model examines the relationship between customer economics and technology adoption—net present value (NPV), internal rate of return (IRR), and payback time for adopting DG-PV with or without a storage system. The model optimizes the distributed energy resource system configuration to yield the highest NPV given technology costs, appropriate investment tax credits, and retail and export rates. The model then applies optimum results to a regression-based relationship of previous DG-PV adoption to determine the number of future installs and the total sum of capacity installed. This approach allows for distributed energy values to be optimized and forecasted based on customer logic and economics, then integrated into the system resource mix resource. The model can also integrate explicit integration costs to fine-tune the customer adoption levels as necessary.

The following assumptions were used in DG-PV forecasts for use in our December 2016 PSIP analysis:

- Progression of technology costs for DG-PV technology from 2016–2045.
- Progression of technology costs for customer storage technology from 2016–2045.
- Future value of storage based on the Black & Veatch Adaptive Planning for Production Simulation model.
- Historical relationships for Hawai‘i, by island, between payback time and levels of customer adoption for DG-PV.
- PV irradiance profiles for each island served.
- Company class load study consumption profiles for each rate schedule.
- Current and addressable populations for DG-PV and customer storage.

The model then outputs the:

- Optimum NPV, IRR, and payback period for a given load profile, system configuration, rate schedule, and build year.
- Overall number of installed DG-PV systems and installed capacity through 2045 based on NPV and payback periods.

CUSTOMER ENERGY STORAGE SYSTEM ADOPTION MODEL

The proprietary Customer Energy Storage System Adoption Model (also developed by the Boston Consulting Group) forecasts customer installations of storage. The model first calculates economics (including payback time) of customer-sited storage installed in a given year based on the total value of storage that it provides. Based on this payback, the model forecasts the percent of eligible customers that adopt storage systems. Eligible customers are assumed to be those who have yet to install a storage system. The correlation of payback to percent of eligible customers is based on the historical correlation of payback time for a DG-PV system and the percent of eligible customers that adopted DG-PV. Given a similar economic profile, a similar percent of customers adopt a storage system as have adopted historical DG-PV, mainly because the two investments are similar.

The model uses the following as inputs:

- Customer storage technology cost forecasts through 2045, including lithium-ion battery, balance-of-system, installation, and annual O&M costs.
- Customer storage technology performance forecasts through 2045, including energy capacity, power capacity, round-trip efficiency, and equipment life expectancy.
- The value of storage forecasts through 2045 based on Black & Veatch's model, including the value of various grid services that can be fulfilled by storage systems (including day-ahead load shift and time of use, FFR, and regulating reserve), while ensuring no double counting. The value is based on the avoided cost to the electric system for the grid services that the storage systems provide (as calculated by the Adaptive Planning for Production Simulation model).
- Historical payback time of DG-PV.

Using these inputs, the storage system adoption model first calculates customer economics for installing storage systems in a given year, and then forecasts customer adoption of storage systems based on the customer economics. The model then outputs the customer storage system adoption forecasts through 2045 (based on system-optimized compensation at avoided cost).

This modeling tool is suitable to calculate the system-optimal level of standalone storage systems to include in the PSIP planning process for two key reasons:

- It forecasts the amount of cost-effective standalone storage systems that could provide grid services.
- It forecasts customers adopting distributed energy resources by using actual historical correlations between customer payback time and adoption rate.

These forecasts are then used as input to the DR potential forecast and DR avoided cost modeling, which in turn generates DR amounts and load shapes that are included in overall system planning.

PSS/E FOR SYSTEM SECURITY ANALYSIS

Our Transmission and Distribution Planning Division uses the Siemens PTI (Power Technology International) PSS®E (Version 33.7) Power-Flow and Transient Stability software application for transmission grid modeling and for system security analysis. This application is one of three most commonly used grid simulation programs for United States utilities. The application supports the IEEE (Institute of Electric and Electronic Engineer) generic models for generators and inverters. When available, custom models can preclude generic models.

PSS/E is high-performance transmission planning software that has supported the power community with meticulous and comprehensive modeling capabilities for more than 40 years. The probabilistic analyses and advanced dynamics modeling capabilities included in PSS/E provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks. PSS/E is used for power system transmission analysis in over 115 countries worldwide.

PSS/E analyzes the steady state and dynamic performance of transmission networks. It is an integrated, interactive application for simulating, analyzing, and optimizing power system performance and provides probabilistic and dynamic modeling features.

The application has two distinct models: (1) power flow to represent steady state conditions and (2) stability to represent transients caused by faults and rapid changes in generation. The transient conditions are modeled to about 10 seconds post-event to determine whether the system stabilizes or fails.

After major system disturbances, we use PSS/E to verify the system events as well as to verify the modeling assumptions.

Input to PSS/E includes impedances for all the transmission lines, transformers, and capacitors; detailed information of the electrical characteristics of all generators and inverters (including PV panels and wind turbines); and energy storage devices (such as batteries). The model includes relays for fault clearing and under-frequency load shedding (UFLS).

FINANCIAL FORECAST AND RATE IMPACT MODEL

PA Consulting Energy and Utilities team developed the Financial Forecast and Rate Impact Model specifically for modeling the impacts of key metrics (such as revenue requirements, rates, and average customer bills) for the Updated PSIPs. The model's design reflects important and unique characteristics of the Companies' business: timing and frequency of rate cases, revenue adjustment mechanisms (RAM), maintenance of the target capital structure, and customer usage and bill composition. PA Consulting initially developed this financial model for the 2014 PSIPs. Since then, the model has been refined and updated to reflect the most current conditions, including recent regulatory changes to the RAM.

The model comprises a comprehensive and interconnected set of detailed modules, each representing a key aspect of the company's financial framework. These modules calculate average customer bills, income statements, cash flow statement, and balance sheets. Additional modules, in turn, calculate detailed schedules of annual capital expenditures, and annual debt and equity issuances.

The model's foundation uses the PSIP case variables to build a range of company financial data, including:

- Annual reports (income statements, cash flow statements, and balance sheets)
- Schedules of existing debt
- Operation and maintenance (O&M) expenses not covered by the PSIPs
- Annual capital expenditures not directly covered by the PSIP cases (transmission, distribution, and other general expenditures)
- Rate structures
- Projections of customer count and average usage
- Sales forecasts
- Most recent net plant values for all generation units

The Financial Forecast & Rate Impact Model requires two key inputs for each PSIP case—production costs (such as fuel prices, power purchase agreements (PPAs), variable and fixed O&M expenses) and incremental capital expenditures. From this input, the model automatically updates all modules to reflect the resultant financial impact on each PSIP case. These financial impacts—pass-through of fuel and PPA costs, application of the appropriate RAM and surcharges for the capital expenditures, updated rate case calculations, and revised debt and equity issuances—lead to updated revenue requirements, rates, and average bill values.

Several Modules Comprise the Modeling Tool

Our Budgets and Financial Analysis Department updated and refined this model that was specifically created to perform financial analysis for the December 2016 PSIP.

The Financial Forecast and Rate Impact Model is comprised of several modules (Figure C-18). The model also includes a discussion that contains the inputs feeding into the calculation modules, and a dashboard that captures all the major outputs from the various modules.

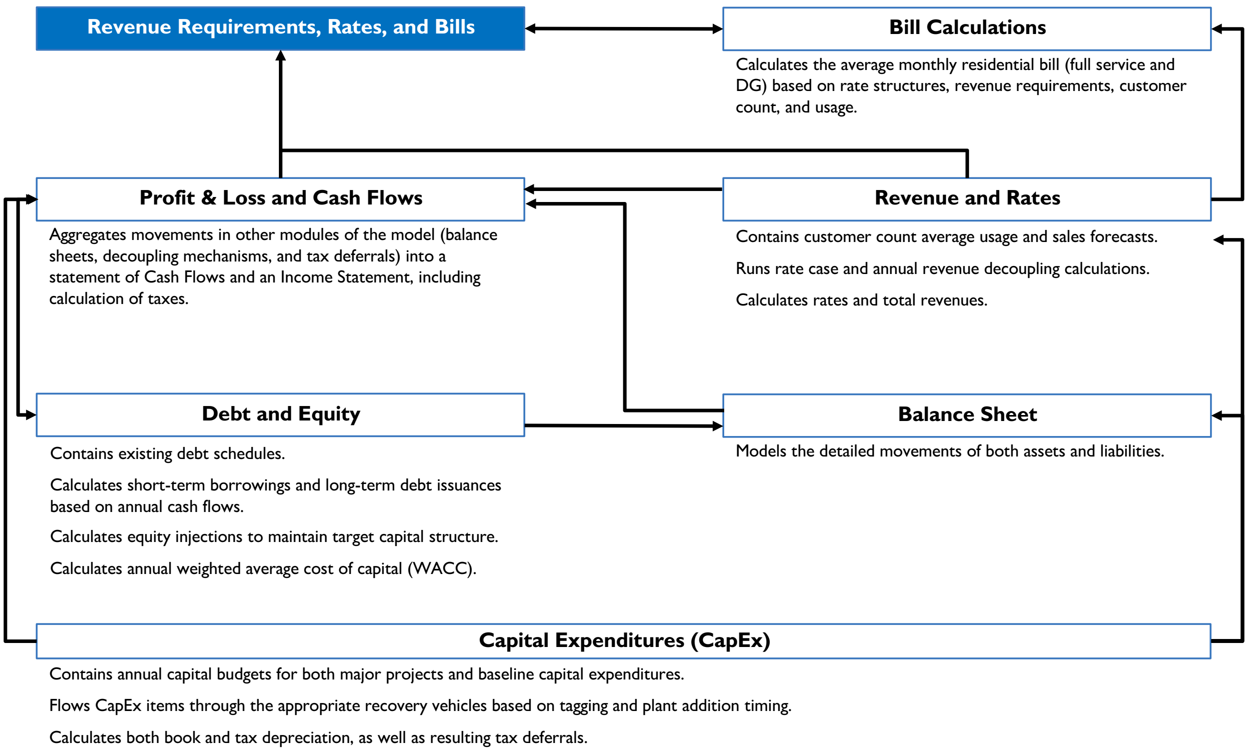


Figure C-18. High-Level Module Structure of the Financial Forecast and Rate Impact Model

Bill Calculations

This module calculates the average monthly bill for full service and DG-PV residential customers. It:

- Calculates average bills under both current rate structures and the proposed DG-PV framework, with fixed rates calculated for both cases.
- Bases the bill calculations on forecasts of annual number of DG-PV customers and usage, production, and export for an average DG-PV customer.

Profit & Loss and Cash Flow

This module primarily aggregates movements from other modules of the model (for example, balance sheet, decoupling mechanisms, and tax deferrals) into a statement of Cash Flows and an Income Statement.

For the statement of Cash Flows:

- Produces detailed schedules of operating, investment, and financing cash flows.
- For operating cash flow, key inputs from other modules include depreciation, change in tax deferrals, change in regulatory assets, and change in accounts receivable and accounts payable.
- Investment cash flow is driven by capital expenditures, which are calculated and picked up from the CapEx module.
- Financing cash flow is driven by the base dividend payments calculated from Net Income in the Income Statement, combined with the debt and equity issuances, and additional dividend payments calculated in the Debt and Equity module.

For the Income Statement:

- Key movements picked up from other modules include Total Revenues, Revenue Balancing Adjustment (RBA), depreciation, and interest expenses.
- Fuel, PPA, and variable and fixed production O&M costs come directly from the PSIP production simulation input, while the remaining O&M items are escalated annually by inflation, adjusted for any specific project-related savings or cost increases.
- Income and revenue taxes are calculated directly, with tax deferrals added from the CapEx module.

Revenue and Rates

This module contains various calculations that add up to a total annual revenue requirement:

- Periodic rate case calculations, with both a calculation of allowed return in order to adjust rates, and a calculation of net allowed revenue for RBA adjustments.
- Detailed RAM and RBA calculations, which reflect the most recent adjustments to the RAM.
- Mark-up of fuel and PPA costs by the revenue tax adjustment factor, to allow pass-through in rates.
- Calculation of total effective rates, by summarizing and adding up the different rate components contributed by RAM, RBA, other surcharges, rate case adjustments, and fuel and PPA pass-through.

- Calculation of total annual revenues, by multiplying the total effective rate with the total forecasted sales provided by (and used in) the PSIP production simulation.

Debt and Equity

This module calculates short-term borrowing, long-term debt issuance, equity injections, and additional dividend payouts:

- Based on an objective to maintain a minimum ending cash balance, short-term borrowing, and long-term debt are used to cover any shortfalls from the net cash flow before financing. Short-term borrowing is exhausted first, with any remaining shortfall covered by long-term debt.
- Upon issuance of debt, equity injections are calculated (if necessary) to maintain the target capital structure.
- Interest expense on new debt is calculated, with short-term borrowings carrying full interest expense in the year of issuance, and long-term debt carrying half a year's interest expenses in the year of issuance, and a full year of interest expense starting in the year following issuance.
- In years with equity over the target ratio, the model calculates additional dividend payments to achieve target capital structure.
- The weighted average cost of capital by year is calculated based on currently-authorized equity returns and forecasted debt rates using the target capital structure.

Balance Sheet

The module presents detailed annual assets movements, including:

- Utility Plant in Service, Accumulated Depreciation, and Construction Work in Progress, driven by annual changes of these items in the CapEx module.
- Annual change in Customer Accounts Receivables are based on annual relative change in Total Revenues.

Also presents detailed annual liabilities movements, including:

- Common Stock and debt balances are driven by calculations in the Debt and Equity module
- Any increase in Retained Earnings is net of any additional dividends paid out as part of the optimization of the capital structure.
- Accounts Payable adjusted annually based on average relative annual change in capital expenditures, fuel, and PPA costs.

For both assets and liabilities, all items that are not explicitly driven by calculations in other parts of the model are kept constant.

Capital Expenditures (CapEx)

This module contains detailed annual capital budgets, and calculations of surcharges, securitization (if applicable), and depreciation (book and tax). The module:

- Details capital expenditures and plant additions by year for baseline and major projects (RAM definition).
- Summarizes plant additions by asset category for depreciation purposes and allows for the inclusion and exclusion of specific projects depending on the cases modeled.
- Summarizes plant additions by surcharge category (Preapproved Baseline, Major Project, or REIP) for decoupling calculations in the Revenue and Rates module.
- Calculates average baseline capital investments for use in the RAM adjustment.
- Calculates accumulated depreciation and depreciation expense by asset (production plant) and by asset category (transmission, distribution, and general).
- Calculates tax depreciation and subsequent deferred tax impact on book and tax depreciation differences.
- Calculates the annual securitization payments associated with the retirement and removal of individual generating units (if applicable).

D. Current Generation Portfolios

HAWAIIAN ELECTRIC SYSTEM

Hawaiian Electric's generation capacity has a mix of utility-owned generation as well as generation from independent power producers (IPPs).

Utility-Owned Generation

Kahe Generating Station. The Kahe generation station has six steam units, all baseload generation, with a combined nameplate capacity of 651 MW, with 620 MW net generation. These are Hawaiian Electric's most efficient units. The station has black start capability.

Waiau Generating Station. The Waiau generating station has eight units: six are steam units and two are diesel. Two are baseload units; four are cycling units; and two are quick-start combustion turbines. Their combined nameplate capacity is 499 MW, with 481 MW net generation. The station has black start capability.

Campbell Industrial Park (CIP). The CIP generating station has one combustion turbine, CT-1, which runs on biodiesel. It provides 113 MW net firm generation. The unit is both quick-start capable and black start capable. This peaking unit runs approximately 10% of the time to address peak load times.

Honolulu Generating Station. The Honolulu generating station, located in the downtown load center, has two steam units with a combined nameplate capacity of 113 MW, with 107 MW net generation. Both are cycling units. These units were deactivated in January 2014.

Our utility-owned generation fleet (summarized in Table D-1) has served our customers for many decades.

Unit	Type	Fuel	Capability (MW)		Age (years)
			Gross	Net	
Baseload (Load Following)					
Kahe 1	Reheat Steam	LSFO	86.0	82.2	54
Kahe 2	Reheat Steam	LSFO	86.0	82.2	53
Kahe 3	Reheat Steam	LSFO	90.0	86.2	47
Kahe 4	Reheat Steam	LSFO	89.0	85.3	45
Kahe 5	Reheat Steam	LSFO	142.0	134.6	43
Kahe 6	Reheat Steam	LSFO	142.0	133.8	36
Waiau 7	Reheat Steam	LSFO	87.0	83.3	51
Waiau 8	Reheat Steam	LSFO	90.0	86.2	49
Baseload: Total Capability/Average Age			*812.0*	*773.8*	*47.3*
Cycling					
Waiau 3	Non-Reheat Steam	LSFO	49.0	47.0	70
Waiau 4	Non-Reheat Steam	LSFO	49.0	46.5	67
Waiau 5	Non-Reheat Steam	LSFO	57.0	54.5	58
Waiau 6	Non-Reheat Steam	LSFO	56.0	53.7	56
Cycling: Total Capability/Average Age			*211.0*	*201.7*	*62.8*
Peaking					
Waiau 9	Simple Cycle CT	LSFO	53.0	52.9	44
Waiau 10	Simple Cycle CT	LSFO	50.0	49.9	44
CIP CT-1	Simple Cycle CT	Biodiesel	113.0	112.2	8
Peaking: Total Capability/Average Age			*216.0*	*215.0*	*32.0*

Table D-1. Hawaiian Electric Generating Units

Hawaiian Electric's baseload units average 47 years of age, while the cycling units average 63 years. The combined average age of all steam units is 52 years. While our existing generation fleet does well in serving stable, predictable, consistent loads, they are not as capable as modernized generation in effectively managing system stability with higher levels of variable generation.

As the roles of firm generation assets evolve, the technical and operational capabilities of these units must match their new use pattern. To meet the future requirements, many existing generators must be modified or replaced in order to cost-effectively supply supplemental energy, fast balancing services, and other requirements identified for reliable and secure power delivery in the future. Among other attributes, new assets need to have operational flexibility: the ability to start quickly, ramp up and down at high rates, and must be designed to regularly start and stop multiple times daily even after long periods of being offline. The baseload steam units in Hawaiian Electric's fleet do not fully possess these characteristics and will need replacement with modern units that do.

Until such time that replacements generating assets come into service, our existing steam generating fleet will serve our customers in an increasingly dynamic way for many years. Our peaking and cycling units will continue to fulfill their existing roles in the upcoming years. Our baseload (load following) units, however, will be assuming new roles in supporting the system. When renewable generation is high (such as high solar days), some of our reheat units may need to cycle offline while others will be at new lower minimum loads. We will continue to maximize the flexibility of these units to support our transition to the 100% RPS while considering potentially more cost-effective and beneficial solutions.

Independent Power Producer (IPP) Generation

H-POWER. The Honolulu Program of Waste Energy Recovery (H-POWER) is a municipal solid waste refuse to energy plant that generates 68.5 MW of baseload, firm generation.

AES Hawai'i. The AES unit is a coal fired plant that generates 180 MW of baseload generation.

Kalaeloa. The Kalaeloa cogeneration (combined-cycle) plant burns LSFO to generate 208 MW of baseload generation.

Kahuku Wind. The Kahuku Wind facility generates up to 30 MW of variable generation.

Kawailoa Wind. The Kawailoa Wind facility generates up to 69 MW of variable generation.

Kapolei Sustainable Energy Park. The Kapolei Sustainable Energy Park features over 4,000 solar panels that generate 1 MW of variable generation.

Kalaeloa Renewable Energy Park and Kalaeloa Two. Together, these two solar photovoltaic installations generate 10 MW of variable renewable generation.

Waihonu Solar PV. The Waihonu Solar PV facility near Mililani provides 6.5 MW of variable renewable generation through the Tier 3 Feed-In Tariff (FIT) program.

Unit	Fuel	Net MW	Delivery Type
H-Power	Refuse	68.5	Baseload
AES	Coal	180.0	Baseload
Kalaeloa	LSFO	208.0	Baseload
Kahuku Wind	Wind	30.0	Variable
Kawailoa	Wind	69.0	Variable
Kapolei Sustainable Energy Park	PV	1.0	Variable
Kalaeloa Renewable Energy Park	PV	5.0	Variable
Kalaeloa Two	PV	5.0	Variable
Waihonu Solar PV	PV	6.5	Variable
Total	—	*573.0*	—

Table D-2. O‘ahu IPP Generation Units

Waianae Solar. The 27.6 MW Waianae Solar project is nearing completion and is scheduled for commercial operation in early 2017.

Planned Near-Term Changes to Current Hawaiian Electric Generation

The PSIP analysis assumes removing from service of much of the current thermal generation by 2045. The timing considers several factors: the overall cost to customers for different resource options, maintaining adequacy of reliable service and adequacy of supply (AOS), the need for increased flexibility, and the successful implementation of new resources to replace the current thermal generation. The "Fossil Generation Retirement Plan" in Appendix M: Component Plans discusses and provides the long-term plan.

Waiau 3 and Waiau 4

Our PSIP analysis assumes that Waiau 3 and Waiau 4 are removed from service between 2020 to 2023, depending on the resource plan. E3's analysis determined the earliest possible removal from service to be 2020 based solely on economic decisions and threshold planning reserve margin (PRM) planning criteria. E3 also analyzed an alternative removal schedule (provided by us) that factors in additional adequacy of supply parameters.

The 2014 PSIPs targeted these units for deactivation at the end of this year, 2016, based on the assumption they would no longer be needed for adequacy of supply. However, based on updated Loss of Load Probability (LOLP) analysis done in conjunction with Hawaiian Electric's 2015 AOS report using a guideline of 4½ years per day, removal of Waiau 3 and Waiau 4 will result in a 2017 reserve capacity shortfall of 50 MW. The AOS report stated that reserve capacity shortfalls could be mitigated "by deferring future deactivation of units, increasing Demand Response Programs, reactivating units that are currently deactivated, or acquiring additional firm capacity through a competitive bidding process".

Hawaiian Electric's 2016 AOS report assumed keeping Waiau 3 and Waiau 4 available for service until the end of 2017 as the preferred mitigation option to avoid a capacity shortfall in 2017. However, shortfalls are still projected after 2017, even when the Schofield Generating Station is in service in 2018. Retaining Waiau 3 and Waiau 4 beyond 2017 virtually eliminated reserve capacity shortfalls. Therefore, Waiau 3 and Waiau 4 will remain in service until other resources are added to the system that allow for their removal without resulting in adequacy of supply shortfalls.

Dates when Waiau 3 and Waiau 4 can be removed from service will be determined as specified in "Fossil Generation Retirement Plan" in Appendix M: Component Plans.

Honolulu 8 and Honolulu 9

The PSIP analysis assumes that Honolulu 8 and Honolulu 9, which are currently deactivated, are retired and converted to synchronous condensers in 2021 to enhance power line voltage regulation.

Hawaiian Electric's 2016 AOS report assumed Honolulu 8 and Honolulu 9 remained deactivated until 2020 and beyond. We will not need to return these unit to service if Waiau 3 and Waiau 4 remain in service until the end of 2020, and the Schofield Generating Station comes online in 2018 as planned, unless other generating units suffered catastrophic problems.

Should actual peak demand exceed forecast, adequacy of supply could require returning Honolulu 8 and Honolulu 9 to service. The decision will consider other mitigating measures (such as running new DR programs, acquiring additional firm capacity, deferring other unit deactivations, and refining generating unit planned outage schedules). Returning Honolulu 8 and Honolulu 9 to service would take about three months.

Status of Existing Firm Generation PPAs

Since we filed our April 2016 PSIPs, we have changed the assumptions for some of our Independent Power Producers on O‘ahu: AES Hawai‘i; and Kalaeloa Energy Partners (KPLP)

AES Hawai‘i

The 2016 PSIP analysis assumes that our power purchase agreement (PPA) with AES Hawai‘i on O‘ahu will not be renewed when it expires on September 1, 2022. Our ability to integrate more renewable generation onto the grid in the coming decades is improved without a large, inflexible single generator such as AES. Under the current PPA, AES provides a large block of coal-fired generation that Hawaiian Electric must accept. Without this constraint and its relative inflexibility, increased amounts of renewable energy can more easily be integrated onto the system. The unit provides relatively little ancillary services.

In the near term, to address potential generation reserve shortfalls, AES can provide additional capacity to help ensure reliable service until additional firm generation is available. On January 22, 2016, we filed an application with the Commission seeking approval of Amendment No. 3 to our existing PPA with AES Hawaiʻi. If this amendment is approved by the Commission, AES would provide an additional 9 MW of firm, dispatchable capacity and associated energy from the existing power plant. While this could be called upon as needed, we are not required to use it. Because AES provides the lowest cost energy, this addition helps lower customer bills in the near term. The amendment will not extend the term of the PPA.

Kalaeloa Energy Partners (KPLP)

The Oʻahu-based Kalaeloa Plant's combined-cycle design has the operational flexibility required to support the needs of a renewable generation fleet. The existing PPA for the Kalaeloa Plant, however, is restrictive in not allowing us to operate the plant with the flexibility that will be required in the future. Operating restrictions include limitations on startup times, ramp rates, and minimum load. In addition, the unit's fuel source is inflexible; we would like to have more fuel sources available to minimize costs to the customer.

The ability to operate KPLP more closely aligned with its design would enable the facility to better support our future renewable fleet. Options to remove these restrictions are ongoing and could consider several alternatives. Should the PPA expire and KPLP cease to provide firm capacity, we might seek additional capacity by deferring future deactivation of units, increasing DR programs, optimizing maintenance schedules, reactivating currently deactivated units, or acquiring additional firm capacity.

The 2016 PSIP analysis assumes the same operational flexibility of the KPLP plant (described herein) after the end of the existing PPA.

Hawaiʻi Electric Light: Hamakua Energy Partners (HEP)

HEP is a reliable, flexible firm capacity resource on Hawaiʻi Island that continues to be critical in meeting adequacy of supply and system security needs with reasonable energy costs.

On February 12, 2016, Hawaiian Electric and Hawaiʻi Electric Light submitted an application (Docket No. 2016-0033) requesting the Commission issue an order approving the purchase of the 60 MW dual-fuel combined-cycle HEP plant and its related assets. The application describes the purchase terms and the benefits to our customers.

Company acquisition would allow economic dispatch of the plant based on the true heat rate, which results in lower costs than the contractual heat rate, and remove the single-start-per-day restriction. The purchase will remove the fixed contractual capacity charge. The PSIP assumes utility ownership of HEP, reflecting the actual heat-rate, variable costs under utility ownership, and capability for more than one start per day.

Hawai'i Electric Light: Hu Honua

The PSIP analysis does not assume Hu Honua is available.

Hawai'i Electric Light: Puna Geothermal Venture (PGV)

PGV experienced capacity reductions following tropical storm Iselle. The facility has completed well work and has increased its production. The PSIP analysis assumed PGV at 38 MW from January 2016. Though at present it remains at 34.5 MW capacity, it is expected to achieve a 38 MW capacity within the next few months after controls work and testing.

Hawai'i Electric Light: Geothermal Request for Proposal (RFP)

Hawai'i Electric Light issued an RFP for additional geothermal generation. The only project bidder that met the minimum threshold requirements for selection to the Final Award Group in the Geothermal RFP determined that developing the proposed geothermal project would not be economically and financially viable and therefore a near-term geothermal project resulting from this RFP is not a base assumption in the analysis.

Hawai'i Electric Light remains committed to the development of geothermal on the island of Hawai'i if it is in the best interest of its customers. While Hawai'i Electric Light is disappointed that the Geothermal RFP did not result in a viable geothermal project, we remain hopeful that geothermal generation can be a viable option on Hawai'i Island in the future. This means it can help Hawai'i meet its 100% renewable energy goal while lowering customer bills, reducing Hawai'i's dependence on imported oil, allowing for continued integration and management of variable renewable resources, and maintaining reliability of service. Geothermal resource additions were considered as potential future options in the development of the PSIP.

Maui Electric: Hawaiian Commercial & Sugar (HC&S) Closure

Maui Electric's PPA with HC&S allows us to schedule up to 4 MW of firm capacity during certain months of the year. The PPA term originally continued through

December 31, 2017. On January 6, 2016, HC&S issued a Notice of Termination of Power Purchase Agreement, which specified that HC&S's contribution to the Maui Electric power grid would end on January 6, 2017.

The Maui Electric analysis assumes HC&S contributes no generation in 2017 and beyond.

Maui Electric will continue discussions with HC&S about potential energy partnership opportunities that can result from future HC&S operations, including a locally-sourced biofuel supply.

Generation Modernization On O'ahu

Hawaiian Electric will seek to replace firm generating capacity for the island of O'ahu as existing power plants age and as new flexible (and efficient) generation technology becomes necessary to integrate large amounts of variable renewable energy resources on the island grid. This modernization process has already begun as the Schofield Generating Station (SGS) and the Airport Dispatchable Standby Generation (DSG) projects are currently under construction. Other near-term planned additions include a microgrid concept at Marine Corps Based Hawai'i (similar to the SGS project) and a power barge located in Pearl Harbor.

Schofield Generating Station

The Schofield Generation Station is currently under construction on 8.13 leased acres at the Schofield Barracks Army facility in central O'ahu. The power plant will generate 50 MW (6-unit x 8.4 MW) of firm, fast-start, dispatchable energy. The plant, with its installed reciprocating engines, will be able to quickly start up, shut down, or change its output in response to sudden changes in solar and wind generation. The Schofield facility, once online, can reach synchronous level in less than one minute, and attain full load in six minutes. As a result, the generating station enables the addition of more variable renewable generation to the grid.

Hawaiian Electric will develop, own, and operate the facility, and its generation will serve the O'ahu electric grid. The power plant will also add a measure of energy security to the Army installation. In an emergency, the Army will be able to isolate the power plant to provide reliable generation to the Schofield, Wheeler, and Kunia bases so the Army and National Guard can carry out their missions of national defense and emergency response.

The Schofield Generation Station will provide a number of benefits for the Oʻahu grid. The plant:

- Will improve the reliability and resiliency of the Oʻahu grid.
- Will enable adding increased amounts of variable renewable energy.
- Help alleviate a portion of the projected shortfall in reserve capacity in 2018 and succeeding years.
- Will increase system reliability and, as a result, minimize the potential for future generation shortfall.
- Will provide additional energy security to Oʻahu because of its siting at high elevation away from sea level.

The plant will run on a mix of fossil fuel and biofuel and is targeted for operation in spring 2018.

Airport DSG

The Airport Dispatchable Standby Generation (DSG) unit—originally scheduled for completion in 2013, but delayed until early 2017 because of design changes—offers emergency generation for the airport and limited duty dispatchable generation for the Oʻahu grid. The DSG installation will consist of four 2.0 MW internal combustion engines (ICEs) that burn biofuel, for a total capacity of 8 MW.

The DSG will be owned by the Airport division of the State of Hawaiʻi's Department of Transportation. The DSG is a prioritized power facility; it's primary purpose is to provide all 8 MW of power to the Honolulu Airport within five minutes of an outage. When not providing emergency power to the airport, Hawaiian Electric can dispatch individual or all of the 2 MW units to provide additional capacity to the Oʻahu power grid, for up to 1,500 hours per year per unit.

The Companies are providing the funding to build the DSG. We will monitor the DSG's operability and status, manage and pay for routine maintenance and operating costs, and pay for the fuel. The ICEs that power the DSG will enable us to better manage and integrated increasing amounts variable renewable generation.

Marine Corps Base Hawaiʻi (MCBH) Microgrid Concept

The Marine Corps and the Navy are seeking enhanced energy security for their bases, similar to what is being done with the Army and the Schofield Generating Station. They are interested in partnering with Hawaiian Electric in this venture, so long as it doesn't require a significant capital investment by the Department of Defense (DoD). There are potential synergies between the goals of the DoD and Hawaiian Electric that could be aligned to develop mutually beneficial solutions to the benefit of all Oʻahu customers.

The Air Force has similar goals and requirements as the Marine Corps and Navy. The Hickam Air Force Base and Naval Base Pearl Harbor were consolidated into the Joint Base Pearl Harbor–Hickam (JBPHH), administered by the Navy. Because of this, meeting the Navy's goals for JBPHH will also satisfy the Air Force's goals.

Hawaiian Electric's goals include:

- Satisfying our customers' needs for cost-effective energy solutions, including the DoD's energy security needs.
- Developing new flexible generating assets that can respond to the variability of variable energy resources (for example, PV and wind power), thus enabling higher penetration levels of those variable resources.
- Enhancing our ability to meet 100% RPS by investing in technologies that are capable of using renewable fuels.
- Improving island-wide energy resiliency, which includes fuel flexibility and smaller, more geographically dispersed generators.
- Improving grid-wide efficiency.
- Improving the response capability of First Responders in an island-wide emergency such as a natural disaster.
- Leveraging low cost, limited use lands for which existing zoning will allow for installation of new generation to minimize development costs.

Hawaiian Electric understands the DoD's goals to include:

- Enhanced energy security and resiliency for its bases, including Marine Corps Base Hawai'i (MCBH) and JBPHH, while minimizing capital costs by leveraging public-private partnerships with utilities.
- Added opportunities to increase renewable energy generation on DoD installations.
- Reduced energy costs.

To provide the services desired by the Marine Corps, it is only practical that generation be located on Marine Corps Base Hawai'i. In addition to meeting the needs of the Marines, adding generation on the windward side of the island can provide resiliency benefits to customers in that area. Therefore, this is the only concept contemplated for this branch of service.

The addition of generation would create a microgrid for the military base where the new generation and existing base resources (such as rooftop PV) have sufficient capacity and grid controls to safely and reliably serve the base's load.

Proposed Project Strategy

Based on Hawaiian Electric's unique and sole capability to deliver energy security to MCBH through integrated generating station and grid operations, the Marine Corps would select Hawaiian Electric as its sole partner for an energy security project on the selected site. Hawaiian Electric, with the support of the Marine Corps, would request from the Commission a waiver from its Framework for Competitive Bidding, based on the Marine Corps' stated requirement to work with the utility to meet military needs.

Hawaiian Electric would lease the project site for in-kind consideration in lieu of monetary rent for the life of the project and design, permit, finance, construct, own, and operate a new, up to 54 MW firm generating station located on the site. The generating station would normally be dispatched to meet grid-wide demands from all Hawaiian Electric customers.

Under conditions identified in the lease, Hawaiian Electric would provide energy security guarantees such that the Marine Corps would gain significantly enhanced energy security for MCBH. These guarantees by Hawaiian Electric would provide the Marine Corps in-kind consideration in lieu of monetary rent payments for the life of the project.

In return for the enhanced energy security, the Marine Corps would contribute to the project with land and other contributions as deemed appropriate for the value of the energy security guarantees provided. The value of the land and other contributions to the project would reduce project costs, thereby saving our customers money compared to siting a similar project at a non-military location.

Site Characteristics, Restrictions, and Needs

The Marine Corps previously identified a suitable site on MCBH (Figure D-1) for a replacement generating station near the existing Hawaiian Electric substation that feeds the base. The size of the potential generating station site is approximately 4.8 acres.

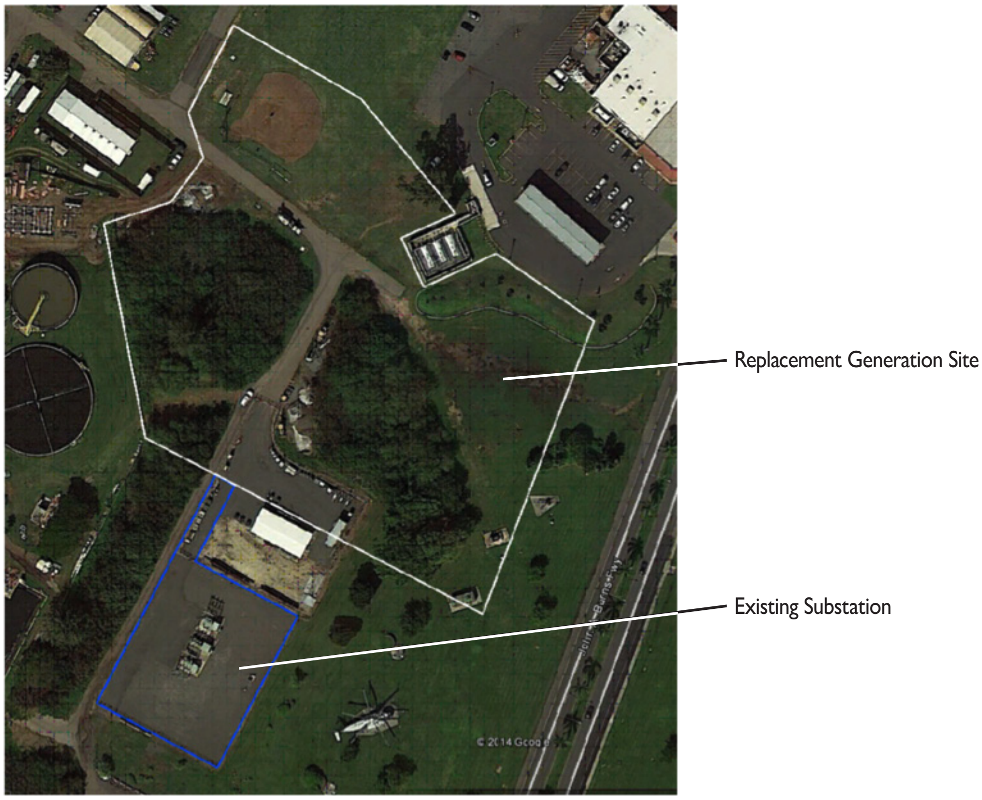


Figure D-1. MCBH Site for Possible Replacement Generation

Based on thermal limitations of the existing 46 kV sub-transmission system feeding the base as well as the need to keep exhaust stacks less than 100 feet above ground level (because of air space restriction associated with nearby helicopter operations), it appears that 54 MW is the maximum size generating station this site could practically accommodate. Furthermore, each of the two 46 kV sub-transmission feeds is individually limited to 30 MW. Therefore, 30 MW would be the maximum size for any individual unit at this site.

No interconnection requirement study has been completed at this location and could result in further restriction of project size. The peak load of MCBH is approximately 16 MW and the intent of a project on this site is to be able to serve the entire peak with one generating unit out of service for maintenance (N-1 design criteria). A preliminary air permit analysis indicates that 54 MW of reciprocating engines with 100 feet tall stacks (3 into 1) can be installed in compliance with all air regulations.

Generating Unit Selection and Project Size

Based on the N-1 criteria, Table D-3 shows the relationship between the number of units and the minimum size of each generating unit for a 60 MW peak load with N-1 criteria.

Generating Units	Minimum Size per Generating Unit (MW)	Total System Capacity (MW)
2	16.0	32.0
3	8.0	24.0
4	5.3	21.3
5	4.0	20.0

Table D-3. Number versus Size of Proposed MCBH Generating Units

Table D-3 indicates the site cannot only accommodate enough capacity to meet the N-1 criteria, but that additional units could be placed at this site to satisfy a more robust criteria or to provide additional energy resiliency for off-base customers.

Previous analysis done for Maui Electric indicated that medium speed reciprocating engines for a station of this size are more cost-effective than using combustion turbines. However, the analysis is dependent on expected capacity usage of the project. Therefore, a specific analysis for O‘ahu should be conducted to determine the most cost-effective technology for this site.

Of the two engine sizes that Wärtsilä offers (9 MW and 17 MW), either could satisfy the design criteria. However, for this size of a project, the 9 MW engine is expected to be more cost-effective and to provide better resiliency and power restoration capability. Thus, if Wärtsilä engines are chosen for this site, the project would use either the 20V32 (liquid-only) or the 20V34DF engine (liquid and gas). Either case would result in a minimum project size of 27 MW.

Waiau Power Barge

Independent of any military considerations, the Company has identified that the waters of Pearl Harbor immediately adjacent to our Waiau Power Plant are ideal for a floating power plant—power barge—and that this concept could result in a very cost-effective method to provide replacement capacity for O‘ahu. Hawaiian Electric is currently working with the Navy to determine the approvals necessary to use the waters of Pearl Harbor for this purpose.

Figure D-2 shows a three-dimensional rendering of one possible configuration at the proposed site.

Figure D-2. Possible Power Barge at the Waiau Generation Station (Artist Rendering)

The power barge concept presents three areas of potential savings compared to land based generating stations at other sites. First, the installed costs of a power barge are lower than any land based construction in Hawai‘i, since the entire station would be built in a shipyard and shipped as a single unit. The on-site construction would be limited to the mooring system and the interconnections for utilities and power. Second, a power barge at the proposed location could utilize existing infrastructure at Waiau Power Plant. Third, the delivery schedule for a completed power barge is less than that for a comparable facility built on site, reducing project costs.

Another potential advantage of a power barge is that it could be designed to be capable of moving between islands to provide emergency power and increase state-wide resiliency. This concept has not been fully studied, but could prove worthy of consideration if it broadens stakeholder support for the project. Such a capability would require additional systems and capabilities onboard the barge, and additional infrastructure on each island where the barge could be deployed. It would also have company and state policy considerations, which would require the support of state and county governments, and possibly Kaua‘i Island Utility Cooperative (KIUC). Project cost allocations associated with these additional capabilities would also have to be determined.

Two types of power barge have been studied, reciprocating internal combustion engine (RICE) units and simple-cycle combustion turbines (CT). For the purposes of the study, 100 MW nominal capacity barges were assumed, although the barge could be larger or smaller based on the outcome of air permitting and interconnection analyses. Barge comparison results are summarized in Table D-4. Based on the analysis, the RICE barge appears to be the better solution for Hawaiian Electric than the turbine barge.

Type	Total Cost	Net Heat Rate (Btu/kWh HHV)
RICE	$160 Million	8,507
CT	$180 Million	8,951

Table D-4. Waiau Power Barge Comparison

Although the Waiau Power Barge concept was initiated to meet Hawaiian Electric needs, because of the close proximity of Waiau Power Plant to JBPHH, Hawaiian Electric is discussing with the Navy the possibility of using the power barge concept to fulfill the Navy's energy security needs as well. In a situation in which the Navy requires a direct feed of electrical power, this concept could take one of two forms:

- The barge could be re-located to a temporary mooring at JBPHH, and connected directly to the base electrical infrastructure.
- The barge could remain in place, but divert power to JBPHH via a direct connection using overhead or underwater cabling.

The peak load of JBPHH is approximately 60 MW. Since the overall capacity of the barge would be determined by Hawaiian Electric's capacity needs and not the Navy's needs alone, a minimum barge capacity of 100 MW is likely to be required. If the Waiau Power Barge concept were selected by the Navy to meet their energy security needs, the project would also need to be able to serve the entire JBPHH peak with one generating unit out of service for maintenance (N-1 design criteria). The 100 MW RICE barge would incorporate six 17 MW units, which would satisfy this criteria. The 100 MW CT barge, as analyzed, has a single 100 MW CT, which would not satisfy the criteria. Other combinations of smaller CT units could be considered, but in general this would increase the cost and the heat rate of the CT barge option, thereby making it even less competitive versus the RICE barge. Therefore, the RICE barge would be a better choice than the CT barge to meet the Navy's energy security needs.

Proposed Project Strategy

If the Waiau Power Barge is only considered as a Hawaiian Electric project for replacement capacity and not anticipated for use as a civil defense or Navy energy security asset, it could be included as a competitive proposal to an open RFP for new generation, as outlined in the Framework for Competitive Bidding. If the barge is anticipated to serve as a state-wide emergency and resiliency asset serving a government need, a waiver from the Framework may be justified. Furthermore, if the Navy determines the power barge would meet their energy security needs, the project would meet several criteria under which a waiver would justifiable. In that case, the implementation would likely be similar to that described for the MCBH microgrid project.

Joint Base Pearl Harbor–Hickam (JBPHH) Microgrid

The Navy is currently studying options for supplying the energy security they desire. While use of the Waiau Power Barge is one of the options they are exploring, they are also considering locations on base at JBPHH for location of a microgrid concept similar to the Schofield Generating Station and MCBH microgrid concepts.

If the Navy determines that a land-based project at JBPHH is viable and preferred, Hawaiian Electric will work closely with the Navy to help bring a land-based project to fruition. In this case, the power barge would still be installed (with the Navy's approval to use the harbor), but not designed to meet Navy energy security needs. The implementation of the land-based project would likely be similar to that described for the MCBH microgrid project. The size of a Navy land-based facility is expected to be in the 60MW to 100MW range. Because it has not been determined yet whether a land-based JBPHH microgrid project will be pursued, it was not included in the PSIP analyses. However, the maturation of this concept could result in it being a specific option in future plans and correspondingly has the potential to accelerate the removal from service of one or more existing generating units.

West Loch Solar Facility

The Company, together with the Navy, have requested Commission approval of a 20 MW solar facility sited at JBPHH, West Loch Annex, on O‘ahu. The Company plans to build, own, and operate the facility. The renewable energy generated by the solar plant will feed the island's electric grid and serve all customers, including the Navy base. In reciprocation of the land needed for the project, we will perform electrical infrastructure upgrades to Navy-owned facilities.

The solar facility, if approved, will generate the lowest cost energy in the state, projected to save customers $109 million during its expected 25-year lifespan when compared with the cost of generating power from an oil-fired plant.

MAUI ELECTRIC EXISTING GENERATION

Maui Electric owns and operates three island electric grids on the islands of Maui, Molokaʻi, and Lanaʻi. Each island has its own unique physical grid design based on system load, demand, and customer needs. Maui Electric's generation portfolio is composed of a mix of renewable and firm resources. Our current generation mix allows us to integrate significant amounts of renewable energy when available, while ensuring reliability for our customers.

Maui Electric generates the majority of its power from combined-cycle and internal combustion engine units, as well as a growing portfolio of renewable energy. Maui's total firm capacity is 251.7 MW (gross). Lanaʻi's total firm capacity is 9.40 MW (gross). Molokaʻi's total firm capacity is 15.18 MW (gross).

Maui Island Firm Generation Assets

The Maui grid includes a growing portfolio of variable renewable energy that includes wind, solar photovoltaic, and hydropower. Our firm generation resources include centralized generating stations comprised of combined cycle and internal combustion engine units, oil-fired steam units, and biomass.

Energy delivery on the Maui System from the generation stations is through 69 kV transmission and 23 kV sub-transmission lines. Maui has 65 distribution substations, situated near large customer load centers (towns, industrial centers, subdivisions) to allow power to be extracted from the transmission network and lowered to voltages that can be safely and efficiently distributed to customers.

Maui Electric's existing dispatchable generation fleet comprises two main power plants at Kahului and Maʻalaea. These plants include:

- Quick-start internal combustion engines (ICEs) that provide emergency replacement power and peaking generation.
- Combined-cycle units, comprised of two combustion turbines (CTs), two heat recovery steam generators (HRSGs) or once-through steam generators (OTSGs), and one steam turbine (ST) that provide high efficiency and relatively low cost cycling capability with a one- to two-hour start time, and fast ramping response. These combined-cycle units support the integration of variable renewables resources needed to achieve the 100% RPS goal by 2045.

Older conventional steam units with limited cycling and load ramping capability that are scheduled for retirement by 2024 because of environmental permitting.

Table D-5 lists the Maui island dispatchable generating fleet.

Unit	Type	Fuel*	Capability (MW net)	Age (years)	Type of Operation
Baseload					
Kahului 3	Combustion Engineering	IFO	11.5	62	Baseload (Load Following)
Kahului 4	Babcock and Wilcox	IFO	12.5	50	Baseload (Load Following)
Ma'alaea 14	GM LM2500 CT	LSD	21.0	24	Baseload (Load Following)
Ma'alaea 15	ABB Steam Turbine	n/a	16.0	23	Baseload (Load Following)
Ma'alaea 16	GM LM2500 CT	LSD	21.0	23	Baseload (Load Following)
Combined-Cycle: Total Capability/Average Age			*82.0*	*36.4*	
Cycling					
Ma'alaea 10–11	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	36	Cycling
Ma'alaea 12–13	Mitsubishi /MAN 18V52/55A	LSD	12.5 each	28	Cycling
Ma'alaea 17	GM LM2500 CT	LSD	21.0	18	Cycling (Load Following)
Ma'alaea 18	Mitsubishi Steam Turbine	n/a	16.0	10	Cycling (Load Following)
Ma'alaea 19	GM LM2500 CT	LSD	21.0	16	Cycling (Load Following)
Cycling: Total Capability/Average Age			*108.0*	*24.6*	
Peaking					
Kahului 1	Combustion Engineering	IFO	5.00	68	Peaking
Kahului 2	Combustion Engineering	IFO	5.00	67	Peaking
Ma'alaea 1	GM EMD 20-645 ICE	ULSD	2.05	45	Peaking
Ma'alaea 2–3	GM EMD 20-645 ICE	ULSD	2.50 each	44	Peaking
Ma'alaea X1–X2	GM EMD 20-645 ICE	ULSD	2.50 each	29	Peaking
Ma'alaea 4–6	Cooper PC2-16	LSD	5.60 each	43	Peaking
Ma'alaea 7–9	Colt PC2-16	LSD	5.60 each	38	Peaking
Hana 1–2	Cummins ICE	ULSD	0.97 each	27/32	Peaking/Emergency
Peaking: Total Capability/Average Age			*58.04*	*41.9*	

* LSD = low sulfur diesel; ULSD = ultra low sulfur diesel; IFO = intermediate sulfur fuel oil; n/a = steam turbines powered by waste heat and do not directly use fuel

Table D-5. Maui Island Generating Units

The existing generation, combined with DR and DER, provide operational flexibility to support the integration of more variable renewable energy resources. These assets have low minimum operating loads, cycling capability, quick-start capability, load following and ramping capability, and black start capability.

Combined Cycle Generation Assets

Ma'alaea M14–16 consist of two 21 MW GM LM2500 combustion turbines, two natural circulation HRSGs, and one 16 MW ABB steam turbine. Ma'alaea M17–19 consist of two 21 MW GM LM2500 combustion turbines, two OTSGs, and one 16 MW Mitsubishi steam turbine. These units support the system in several ways.

Support of Renewables. They provide flexible generation and economic bulk supply of energy demand. M17–19 are designed for cycling and supporting the ramping needs. The units are limited by permit constraints to two starts per day. The combustion turbines can be online in 25 minutes following startup. M14–16 are being modified to better support low-load operation. Additional improvements might allow full cycling capability, but further investigation is necessary. The combustion turbines can be online in 25 minutes following startup. M17–19 can be cycled offline as necessary, with a one- to two-hour startup and three-hour minimum down time.

The units are capable of relatively fast ramping (2 MW per minute on AGC) and a minimum dispatch limit of 25%, driven by the covered source permit and 60% based on minimum steam flow through the once-through steam generator.

Support of High-Run-Hour Generation. With a heat rate between 8,330 Btu/kWh and 8,525 Btu/kWh, the combined cycle units provide generation at high efficiencies making them well suited for bulk customer service needs until the required variable and firm renewables are built. Because of this high efficiency, they are well suited to consume biodiesel after 2045 to support the 100% RPS target and minimize the impact on customer bills.

Cycling and Startup Costs. While the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine are impacted by cycling. This cost is included in the production cost modeling. The LM2500 combustion turbines in the Ma'alaea CC units have bypass systems that allows for faster starts with minimal startup cost impact.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5 million was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry data. The budgetary costs were created based on reviewing similar projects and using industry standards.

The identified investment generally include:

- Replacing heat recovery steam generator pressure components.
- Refurbishing generators stators and rotors.
- Upgrading excitation systems.
- Upgrading the transformer and electrical systems.
- Replacing major pumps and motors.
- Upgrading obsolete control systems.

Quick/Fast Start Peaking Generation Assets

The quick/fast-start peaking generation units support the increased variable renewables resources needed to achieve the 100% RPS goal by 2045.

M1–3 and X1–2 are 20-EMD-645 ICE units built in the 1970s and 1980s (manufactured by GM's Electro-Motor Division, thus the EMD designation) with individual maximum loads of 2.5 MW. M4–7 are Cooper PC2-16 ICE units constructed in the mid-1970s, and M8–9 are Colt-PC2-16 diesel engines constructed in the late 1970s, with individual maximum loads of 5.6 MW. M10–M13 are Mitsubishi Heavy Industry (MHI) ICE units manufactured by MAN of Germany, model 18V52/55A, constructed between 1979 and 1989, with individual maximum loads of 12.5 MW. The ICEs provide 96 MW of quick/fast start capability.

These units support the system in several ways.

Support of Renewables and Load Loss. The various types of ICE units support the variable renewable generation differently.

The General Motors (GM) Electro-Motive Diesel (EMD) ICE units (2.5 MW units) are quick start and can be at full load in less than 10 minutes. These units support renewable generation because they are offline reserve generation that can be deployed in response to cloud cover or wind events resulting in un-forecasted losses of variable generation.

The Cooper PC2-16 units (5.6 MW units) can come online 15 minutes after start, and take an additional 50 minutes to reach full load. Current constraints dictate that the units need to be started sequentially rather than simultaneously. They serve the system best when used for compensating for forecasted loss of variable generation and recovery following an event to supplement other sources generation.

The MHI 18V52/55A ICE units (12.5 MW units) can come online 17 minutes after a start command is given and be at full load in 117 minutes. They serve the system best being available for forecasted lack of variable generation and supporting peak loads.

Cycling and Start-Up Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

The GM EMD ICE and Cooper PC2-16 ICE units have a large user base resulting in long term availability of parts. The MHI ICE units are expected to be serviceable with replacement parts for many years to come as both Mitsubishi Heavy Companies and MAN continue to produce engines (different model) and maintain the engineering and facilities to produce parts for these engines.

Support of System Stability. While they supply load replacement very quickly, the ICE does not provide load flexibility and therefore does not support all type of system stability needs. The GM EMD ICE units (2.5 MW units) cannot be incrementally controlled through the SCADA/EMS system and are not used for regulation.

Conventional Steam Generation Assets

Kahului Power Plant has four steam units. Kahului 1 and Kahului 2 are currently in a peaking status. Kahului 3 and Kahului 4 are baseload units currently operating at low loads while also providing a significant amount of online system regulating reserve. All steam units at Kahului will be retired by 2024 for environmental reasons.

When the Kahului plant is fully retired, replacement generation is needed to continue to support the variable renewable resources and the system demand.

Lanaʻi Firm Generation Assets

The Lanaʻi system is small—its generation needs are met by six 1.0 MW EMD diesel engines and two 2.2 MW Caterpillar 3608 diesel engines. A Caterpillar C32-1100 combined heat and power unit (CHP) will provide 800 kW of power and heat to support Manele Bay hotel loads starting in late 2017. As with the Maui units, the EMDs are expected to be serviceable well into the future. In addition the La Ola photovoltaic installation, owned by Lanaʻi Sustainability Research, contributes 1.2 MW.

Miki Basin Units LL-l to LL-6 (six 1,000 kW diesel engine-generator units totaling 6,000 kW) were converted to peaking status at the end of 2006, and as such, can be relied on for 5,000 kW of capacity to the Lanaʻi system. These EMD units are capable of starting in less than 10 minutes, and are well suited for responding to un-forecasted changes in variable generation. The Caterpillar engines are more efficient than the EMDs; they are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar 3608 engines can start and be online in 17 minutes and at full load in 22 minutes.

The size of the Lanaʻi system, with the flexibility of the current generation mix, help support the transition to 100% renewables. The units can compensate for changes in generation as well as supplement energy storage use. Lanaʻi's distribution system is operated at 12.47 kV, 6.6 kV, and 2.4 kV. Lanaʻi does not currently have any transmission lines in place.

Unit	Type	Fuel*	Capability (MW net)	Age (years)	Type of Operation
Miki Basin LL1–LL6	EMD diesel engines	ULSD	1.0 each	60	Peaking
Miki Basin LL7–LL8	Caterpillar 3608 diesel engines	ULSD	2.2 each	20	Baseload
Manele Bay CHP	Caterpillar C32-1100	ULSD	0.8	0	Not in Service
All Generation: Total Capability/Average Age			*11.2*	*40*	

Table D-6. Lanaʻi Utility-Owned Generation Units

Molokaʻi Firm Generation Assets

The Molokaʻi system is also small. Molokaʻi has capacity to generate 12 MW (gross) of power at the Palaʻau Power Plant. The Molokaʻi grid includes a centralized generating station with nine diesel internal combustion units and one diesel combustion turbine.

Palaʻau 7, 8, and 9 (three 2.2 MW Caterpillar 3608 diesel engines) operate in baseload service (often just two concurrently). Palaʻau 1 and 2 (two 1.25 MW Caterpillar 3516 diesel engines), and Palaʻau 3, 4, 5, and 6 (four 0.97 MW Cummins KTA50 diesel engines) and Palaʻau 10 (2.0 MW Solar Centaur T4001 combustion turbine) operate in peaking service. Because of the age and operating history of these units, Maui Electric includes one Caterpillar unit and two Cummins units (1.25 + 0.97 + 0.97 = 3.19 MW) toward firm capacity for the Molokaʻi system. Palaʻau also has one 2.22 MW Solar Centaur T4001 combustion turbine. The Molokaʻi engines have a large user base and are expected to be serviceable with parts for well into the future.

The Caterpillar 3608 engines are more efficient than the other engines and are well suited for meeting system peaks and forecasted changes in variable generation. The Caterpillar engines can start and be online in 17 minutes and at full load in 22 minutes. This makes them ideal for efficiently supporting forecasted needs.

The flexibility of the generation fleet supports the transition to 100% RPS by providing quick starting and quick ramping capabilities to compensate for losses of forecasted and un-forecasted variable generation as well as supporting peak loads. The units are well equipped to support the transition to 100% RPS by providing grid services such as frequency and voltage control, meeting changes in generation need, and supplementing energy storage as necessary.

The Molokaʻi system includes an overhead transmission line from Palaʻau Generation Plant to Puʻunana Substation. Molokaʻi's transmission and distribution systems are operated at 34.5 kV, 12.47 kV, 4.16 kV, and 2.4 kV respectively.

Unit	Type	Fuel*	Capability (MW gross)	Age (years)	Type of Operation
Palaʻau 7–9	Caterpillar 3608 diesel engines	ULSD	2.20 each	20	Baseload
Palaʻau 10	Solar Centaur T4001 CT	ULSD	2.22	34	Peaking
Palaʻau 1–2	Caterpillar 3516 diesel engines	ULSD	1.25 each	31	Peaking
Palaʻau 3–6	Cummins KTA50 diesel engines	ULSD	0.97 each	31/25	Peaking
All Generation: Total Capability/Average Age			*15.18 MW*	*27*	

Table D-7. Molokaʻi Existing Generation Units

Maui Electric Variable Resources

Maui Electric's grid includes up to 115.4 MW of generation from renewable sources on Maui, Lana'i, and Moloka'i through a series of power purchase agreements (PPAs) and other interconnection agreements.

Maui Electric's system incorporates wind energy from three wind sites totaling 72 MW of variable renewable generation on Maui island via power purchase agreements. Kaheawa I consists of 20 wind turbines that provide us with 30 MW of variable generation. Kaheawa II consists of 14 wind turbines that provide us with 21 MW of variable generation. Auwahi currently consists of 7 wind turbines that provide us with 21 MW of variable generation.

Makila hydroelectric unit provides Maui Electric with 0.5 MW of variable generation. The La Ola photovoltaic site, owned by Lana'i Sustainability Research, contributes 1.2 MW of variable generation. PPAs for two 2.87 MW solar facilities—Ku'ia Solar and South Maui Renewable Resources—have also been approved by the PUC. Both projects are expected to be placed in-service in 2017.

Unit	Energy	Rating MW	Type
Kaheawa I (Maui)	Wind	30.0	Variable
Kaheawa II (Maui)	Wind	21.0	Variable
Auwahi (Maui)	Wind	21.0	Variable
Makila Hydro (Maui)	Hydro	0.5	Variable
La Ola Solar (Lana'i)	Solar PV	1.2	Variable
Distributed Generation (Maui, Lana'i, Moloka'i)	Mostly Solar PV	92.0	Variable
Total	—	*165.7*	—

Table D-8. Renewable Generation on Maui, Lana'i, and Moloka'i

Planned Near-Term Changes to Current Maui Electric Generation

Maui Electric Kahului Power Plant

Our Kahului Power Plant (KPP) has four steam units totaling 35.92 MW (net) firm capacity. Maui Electric deactivated two units (Kahului 1 and Kahului 2) to conform to our System Improvement and Curtailment Reduction Plan (SICRP),[1] however they were reactivated in 2016 due to system needs. All four units were previously scheduled for retirement by 2019; however, their retirement would have resulted in a reserve capacity shortfall of approximately 40 MW. To ensure enough capacity to meet demand, we

[1] The permit includes various conditions, including a compliance plan which identifies interim milestones to cease water discharge by 2024.

obtained a National Pollutant Discharge Elimination System (NPDES) permit[2] from the State of Hawai'i Department of Health (DOH) with a compliance plan that will allow KPP to continue operating provided we retire the units before November 30, 2024. We currently plan to retire the entire facility in 2022 assuming sufficient replacement resources (including DR and generation) are in operation by then.

Maui Electric Ma'alaea Units

Our Ma'alaea Power Plant has 15 diesel units and 4 gas turbines totaling 208.42 MW (net) of firm capacity. The gas turbines can be configured into two separate combined-cycle systems supplying two steam turbines. We are in the process of modifying the baseloaded combined-cycle system, allowing it to operate at lower levels so that the grid can accommodate more renewable generation. In 2014, we upgraded the generator controls on four of the diesel units so that they could be monitored and operated remotely. These upgrades enable us to better respond to system disturbances and system demands because of increased variable renewable resources on the system.

Maui Electric Moloka'i and Lana'i

Moloka'i has a centralized generating station with nine diesel internal combustion engines (ICEs) and one diesel combustion turbine with combined capacity to generate 12.0 MW (gross) firm capacity. We recently received approval from the DOH to allow for lower minimum operating levels on the two baseload units to accommodate more renewable generation. We completed generator control upgrades for 2016 to improve operation and troubleshooting of the generating units.

Lana'i includes a centralized generating station with nine diesel units with 9.4 MW (gross) firm capacity. We have applied to the DOH to allow for lower minimum operating levels on the two baseload units to accommodate more renewable generation We plan to implement the same generator control upgrades as on Moloka'i. We also plan to operate a Combined Heat and Power (CHP) unit to provide baseload power; it is expected to return to service in 2017.

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[2] *Ibid.*

HAWAI'I ELECTRIC LIGHT SYSTEM

Hawai'i Electric Light currently owns and operates 23 firm generating units, totaling about 181.6 MW (net, maximum capacity), at five generating stations and four distributed generation sites. Three steam units (fueled with No. 6 fuel oil–MSFO) are located at the Hill, and Puna generating stations. Ten diesel engine generators (fueled with diesel) are located at the Waimea, Kanoelehua, and Keahole generating stations. Our five combustion turbines (CTs–fueled with diesel) are located at the Kanoelehua, Keahole, and Puna generating stations. Two of the Keahole CTs are configured to operate in combined cycle with a heat recovery steam turbine. Four distributed generation diesel engines fueled with diesel fuel are located individually at the Panaewa, Ouli, Punalu'u, and Kapua substations (the Panaewa and Kapua units are temporarily located at Kapoho as part of a lava mitigation plan to serve customers potentially isolated by the flow, and will be restored for grid operation).

Two independent power producers (IPPs) provide firm capacity power to our grid. One is a combined-cycle power plant owned and operated by Hamakua Energy Partners LP (HEP); the other is a geothermal power plant owned and operated by Puna Geothermal Venture (PGV).

Our generation fleet has the following capabilities:

- Quick/fast start generation including simple cycle combustion turbines (SCCT) and ICEs that provide emergency replacement power and peaking generation, but at a higher cost than the larger resources. The simple cycle combustion turbines can be used as black start resources.
- Combined-cycle units, comprised of two CTs, two HRSGs, and one ST with high efficiency and relatively low cost. These assets provide cycling capability with a 1–2 hour start time, and have fast ramping capability.
- Older conventional steam units have offline cycling capability, but longer start-up times and less ramping capability when compared to the combined-cycle units.
- Geothermal IPP provides firm energy.

These generating assets, combined with DR resources and DER, provide the flexibility necessary to integrate more variable renewable resources to meet 100% RPS requirements.

Table D-9 lists the dispatchable generating fleet of Hawai'i Electric Light.

Unit	Type	Fuel*	Capability (MW net)	Age (years)	Type of Operation
Combined-Cycle					
Keahole	2 - GM LM2500 CT with ST	LSD	56.3	12/6	Frequency Regulation, Load Following, Cycling
Combined-Cycle: Total Capability/Average Age			*56.3*	*10*	
Steam					
Hill 5	Non-Reheat Steam	IFO	13.5	51	Frequency Regulation, Load Following, Cycling
Hill 6	Non-Reheat Steam	IFO	20.2	42	Frequency Regulation, Load Following, Cycling
Puna 1	Non-Reheat Steam	IFO	15.7	46	Frequency Regulation, Load Following, Cycling
Steam: Total Capability/Average Age			*49.4*	*46.3*	
Emergency/ Peaking					
Kanoelehua CT1	GM Frame 5 SCCT	LSD	11.5	54	Peaking, Emergency, Black start
Keahole CT2	ABB GT-35 SCCT	LSD	13.8	27	Peaking, Emergency, Black start
Puna CT3	GM LM2500 SCCT	LSD	21.0	24	Peaking, Black start
Kanoelehua	Fairbanks Morse ICE	ULSD	2.0	54	Peaking, Emergency
Kanoelehua	3 - GM EMD 20-645 ICE	ULSD	7.5	41–44	Peaking, Emergency
Keahole	3 - GM EMD 20-645 ICE	ULSD	7.5	28–32	Peaking, Emergency
Waimea	3 - GM EMD 20-645 ICE	ULSD	7.5	44–46	Peaking, Emergency
Mobile	4 - Cummins ICE†	ULSD	5.0	17–18	Peaking, Emergency
Peaking: Total Capability/Average Age			*76.2*	*43.4*	
Major Independent Power Producers (IPPs)					
Hamakua Energy Partners	2 - GM LM2500 CT with ST	Naphtha	60.0	16	Frequency Regulation, Black Start, Load Following, Cycling
Puna Geothermal Venture	Geothermal	n/a	38.0	24	Baseload
Major IPPs: Total Capability/Average Age			*90.0*	*18.7*	
Hydroelectric					
Puueo No. 1	Hydroelectric	n/a	2.6	11	Non-Firm
Puueo No. 2	Hydroelectric	n/a	0.75	98	Non-Firm
Waiau No. 1‡	Hydroelectric	n/a	0.75	95	Non-Firm
Waiau No. 2‡	Hydroelectric	n/a	0.35	88	Non-Firm
Hydroelectric: Total Capability/Average Age			*4.35*	*73*	

* LSD = low sulfur diesel; IFO = intermediate sulfur fuel oil; ULSD = ultra-low sulfur diesel.
† Panaewa and Kapua located at Kapoho for lava flow emergency use only.
‡ An application has been submitted to repower Waiau increasing total capacity to slightly over 2.5 MW.

Table D-9. Hawai'i Electric Light Fossil Generating Units

Over 85.5 MW of utility-scale renewable energy capacity is available on Hawai'i Island: 38 MW is firm generation from the IPP Puna Geothermal Venture: 30.1 from IPP wind, and 16.6 run of river hydro (utility-owned and IPP). In addition there is over 2.5 MW of Feed-in Tariff generation, primarily solar and a growing amount of distributed generation (also primarily solar PV).

Unit	Energy	Net MW	Delivery Type
Puna Geothermal Venture*	Geothermal	38	Firm
Puueo No. 1	Hydro	2.6	Variable
Puueo No. 2	Hydro	0.75	Variable
Waiau No. 1†	Hydro	0.75	Variable
Waiau No. 2†	Hydro	0.35	Variable
Tawhiri Power LLC	Wind	20.5	Variable
Hawi Renewable Development	Wind	10.5	Variable
Wailuku River Hydroelectric LP	Hydro	12.1	Variable
Consolidated Installed Residential and Commercial PV	Solar	79.3	Variable
Total	—	*164.9*	—

* PGV is presently at 34.5 but expected to achieve 38 MW considered in the PPA in the near term.
† An application has been submitted to repower Waiau increasing total capacity to slightly over 2.5 MW.

Table D-10. Hawai'i Electric Light Renewable Energy Resources.

Combined-Cycle Generation Assets

The combined-cycle (CC) units support increasing variable renewables resources incorporated to achieve the 100% RPS goal by 2045.

Support of Renewables. They provide flexible generation and economic bulk supply of energy. The units can be cycled offline as necessary, with a 1 to 2 hour startup and three hour minimum down time. The units are capable of relatively fast ramping (4 MW per minute) and have a minimum dispatch limit of 30%–40%, driven by the covered source permit and minimum steam flow through the heat recovery steam turbine. Potential may exist to increase these ramp rates.

Support of High Run Hour Generation. The combined-cycle units are the most efficient conventional plants on the system, well suited for cost effective service of bulk customer energy needs that will continue to be required until dependable replacement renewable resources are available to serve these needs. Because of this high efficiency, they are the most cost-effective resources for future fuel-switching to biodiesel to support the 2045 100% RPS target and minimizing the impact on customer bills.

Cycling and Startup Costs. While the LM2500 combustion turbines do not incur a startup cost, the heat recovery steam generator and the steam turbine may increase costs because of offline cycling.

The LM2500 combustion turbines that are part of the Keahole CC unit have steam bypass systems which allows for faster starts than would be possible without the bypass. It also allows for faster startup in simple-cycle mode for emergency replacement power (22 minutes).

The LM2500 combustion turbines that are part of the HEP CC unit do not presently have steam bypass systems but this might be pursued to add flexibility to increase the support of future renewables as well as lower total cost and faster available replacement power.

Long Term Reliability and Maintenance. The CC units were evaluated for continued operation to 2045. An estimated capital expenditure of $113.5 million was deemed necessary to support long term operations. The capital expenditures represent capital investment over what is normally included in scheduled overhaul cycles. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. The identified investment generally include:

- Replacing heat recovery steam generator pressure components.
- Refurbishing generators stators and rotors.
- Upgrading excitation systems.
- Upgrading the transformer and electrical systems.
- Replacing major pumps and motors.
- Upgrading obsolete control systems.

Quick/Fast Start Peaking Generation Assets

The quick/fast start peaking generation units support the renewable resources needed to achieve the 100% RPS goal by 2045. The ICEs provides 29.5 MW of quick start capability all available in less than three minutes. These units support the system in several ways.

Support of Renewables and Load Loss. These smaller resources quickly allow the system to meet load requirements from the loss of generating units or transmission lines, variability in wind and solar resources because of changes in weather, and emergency peaking needs.

Costs. The ICE units have very low startup costs. They can be used to provide generation when only a small increment is needed, in lieu of starting a larger unit and operating them at an inefficient load-point. The ICE units are well suited for quick starting and numerous starts.

Long Term Reliability and Maintenance. Though some of these units are older, their modular design allows for continuous repair and overhaul extending their life through 2045. These types of units normally do not require any additional capital expenditures to extend their life to 2045.

The GM EMD ICE units have a large user base resulting in long term availability of parts to maintain the engines. The Fairbanks Morse ICE unit has a similar large user base.

The simple cycle combustion turbines (SCCT) provide 46.3 MW of peaking capability, and are used for emergency replacement reserves and peaking energy.

Support of Renewables and Loss of Load. The simple cycle combustion turbines have fast start capability (5–22 minutes) which is not as quick as the ICE units but faster than combined cycle and steam unit startup.

Costs. The cost varies between the different types of SCCT units.

The GT-35 and Frame 5 have a high heat rate, and accordingly, high production costs. These units have the shortest startup times of the combustion turbines: less than 10 minutes. They do incur a maintenance cost for each start, but because of the high production costs, do not incur many starts per year. They are operated primarily for emergency replacement power and short-term energy needs.

The GM LM2500 does not incur a significant maintenance cost for starts. These can be started as needed to support the system needs. These units are relatively efficient, second only to the combined-cycle operation. These units are used for short-term energy needs, in addition to emergency replacement power.

Long Term Reliability and Maintenance. These combustion turbine units are 24 to 54 years old. Their modular design allows for continuous repair and overhaul extending their life through 2045. With limited operation hours, these types of units normally do not require any additional capital expenditures to extend their life to 2045.

Though 54 years old, the GM Frame 5 SCCT has a large user base resulting in long term availability of parts. This type of turbine is still being manufactured today which allows for potential upgrades. The GM LM2500 SCCT is 24 years old. It also has a large user base and is still being manufactured today. This type of combustion turbine is shared with the combined-cycle unit at Ma'alaea, Keahole, and HEP.

The ABB CT35 SCCT is 27 years old and has much smaller user base. Maintaining this combustion turbine may prove more difficult in the next 20 to 30 years. The assumption is that it will be maintained until 2045.

All the simple cycle combustion turbines have the capability to operate in isochronous control (zero-droop or swing unit) for frequency control and stability during major system disturbances and can support system restoration from black start. CT2 is located in Keahole, which allows it to support the minimum generation requirement for the west side of Hawai'i Island for voltage and transmission system constraints and is the only black-start resource available in West Hawai'i

Conventional Steam Generating Assets

The conventional steam generating assets provide many benefits. Hill 5 and Hill 6 cycle to provide steam generated electricity. Puna was placed on seasonal cycling, operating during low generating capacity margins but due to a change in fuel costs, is now operated on a routine peaking cycle serve demand, as the present availability of low-cost fuel has made the unit cost-competitive for operation compared with combined cycle assets.

Support of Renewables. Because of the small size of these steam units, they provide greater dispatch flexibility than larger steam units. The units can be cycled offline with a minimum three hour start time for warm start. With present equipment and controls, these units require extensive manual operation during startup and the startup time may be shortened if equipment is modified. The units have a lower minimum dispatch limit than combined cycle units.

These conventional steam units provide firm capacity and have a sustained ramp rate of 2–3 MW per minute. While presently satisfactory, this ramp rate may not be sufficient for future higher penetrations of variable solar and wind, requiring supplement from other ramping resources. The inertial contribution is relatively high.

The steam units are significantly less efficient than the combined-cycle units. Because of this low efficiency, they would not be cost-effective for higher cost fuels (such as biodiesel) after 2045 to support the 100% RPS target.

Cycling and Startup Costs. The equipment of the entire conventional steam plant is impacted by cycling. This cost is included in the production cost modeling.

Long Term Reliability and Maintenance. Analysis showed that an investment of $49 million will be necessary to maintain reliable operation. The expenditures were calculated based on units running to 2045 and were based on a review of condition assessment, component maintenance history, and review of industry experiences. The budgetary costs were created based on reviewing similar projects and using industry standards. Generally the capital investments include work over and beyond what is normally done during the overhaul cycle and includes:

- Replacing major boiler pressure components.
- Replacing major turbine components.
- Refurbishing generator stators and rotors.
- Replacing excitation systems.
- Replacing transformer and electrical systems
- Replacing major pumps and motors.
- Replacing critical piping and valves.
- Upgrading obsolete control systems.

Operations of the Conventional Steam Generation Assets

Selecting which units will operate to serve the majority of demand is based on providing system security at the lowest cost of meeting the minimum system security requirements, considering the available resources capable of meeting those requirements, and the overall production cost.

System security analysis has identified that at present, the system can generally operate with acceptable reliability with a minimum of four of the existing larger units online. These units can be any combination of three steam units and the LM2500 units, in simple or combined cycle (a plant operating in combined cycle counts as two units to the minimum four unit requirement), with at least one of the units located at Keahole because of voltage and transmission security constraints.

Planned Near-Term Changes to Current Hawai'i Electric Light Generation

The assumptions for generating units are generally consistent with those used in the April 2016 filing. This includes the retirement of Shipman 3 and 4 in December 2015. The dispersed diesel units have increased capacity to 1.25 MW. Two of the units were temporarily relocated to a site in Puna to provide emergency service to customers at risk of being disconnected from the grid by lava flow, and will be returned to the original locations. The units are assumed returned to service. An application to repower Waiau Hydro has been submitted. If this project is approved, the Waiau capacity would increase to over 2.5 MW. The PSIP analysis assumes the repowered turbine is in service.

CONSOLIDATED RENEWABLE GENERATION

Installed Residential and Commercial PV

Over the last ten plus years, we have witnessed an explosion in PV generation, comprised of individual distributed generation and from IPPs. Since 2011, the amount of PV has grown steadily by an average of nearly 100 MW annually. About two-thirds of this capacity is from uncontrollable, must-take residential DG-PV. The remaining one-third is from the combined generation of commercial installations and IPP sites.

Utility	Number of PV Systems			PV Capacity (MW)		
	Residential	*Commercial*	*Total*	*Residential*	*Commercial*	*Total*
Hawaiian Electric	44,267	1522	45,789	243.4	148.6	392.0
Maui Electric	10,148	782	10,930	56.7	30.7	87.4
Hawai'i Electric Light	10,263	647	10,910	52.4	26.9	79.3
Totals	*64,678*	*2,951*	*67,629*	*352.5*	*206.2*	*558.7*

Table D-11. Consolidated Installed Residential and Commercial PV (September 30, 2016)

Figure D-3 depicts the annual growth of combined DG-PV and commercial (IPP) PV generation on the electric power grids of all five islands we serve: O'ahu, Maui, Moloka'i, Lana'i, and Hawai'i Island.

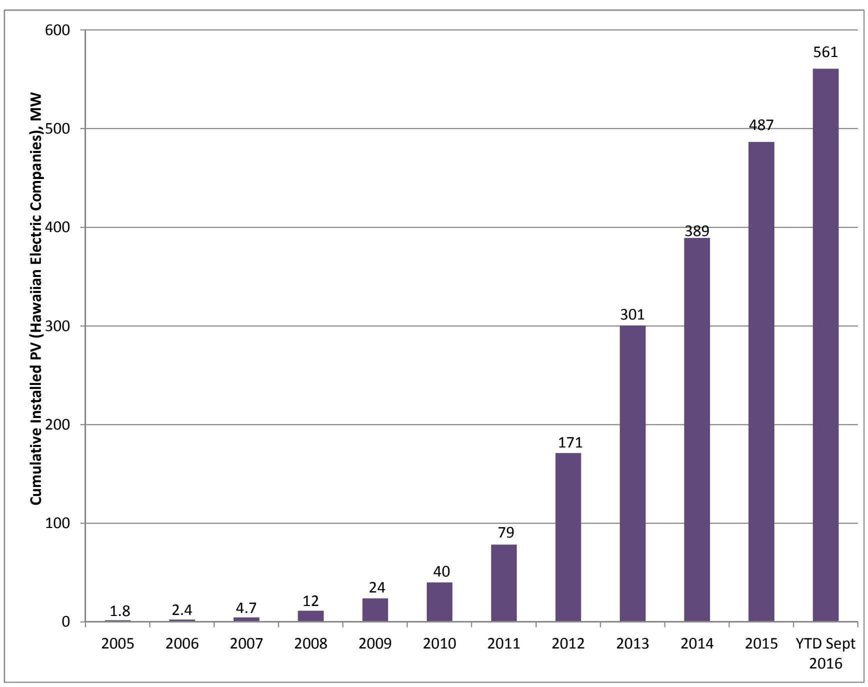

Figure D-3. PV Generation Growth: 2005–2016

Renewable Generation Resources

A number of resources comprise the renewable generation at all three operating utilities. This consolidated total tracks to the RPS milestones that we must meet over the next 30 years. The current milestone is 30% by the end of 2020; the next milestone is 40% by the end of 2030.

Table D-12 breaks out, by operating utility, the generation amount from various renewable resources applied toward meeting RPS.

Electric Energy Generated from Renewable Resources (net MW hours)				
Renewable Resource	**Hawaiian Electric**	**Maui Electric**	**Hawai'i Electric Light**	**Total**
Customer-Sited, Grid-Connected Renewables	464,412	88,956	89,691	643,060
Biomass (including municipal solid waste)	385,846	30,870	0	416,716
Geothermal	0	0	230,495	230,495
Grid-Scale Photovoltaic and Solar Thermal	40,750	7,904	2,557	51,212
Hydroelectric	0	9,823	63,275	73,098
Wind	216,197	264,291	132,293	612,782
Biofuels	52,424	988	0	53,412
Total Renewable Generation	1,159,630	402,833	518,311	2,080,775
Total Company-Wide Sales	6,754,083	1,137,630	1,064,785	8,956,498
RPS Percentage	17.2%	35.4%	48.7%	23.2%

Table D-12. Electric Energy Generated from Renewable Resources (Year 2015)

Notes:

- *Customer-Sited, Grid-Connected Renewables* represent generation from photovoltaic, wind, and hydro systems based on known system installations for 2015 including Net Energy Metering (NEM) installations, non-NEM systems, and Smart Power for Schools (formally Sun Power for Schools) installations. Recorded generation data was used whenever available; otherwise, estimates were made based on reasonable performance assumptions for typical photovoltaic systems.
- Renewable electrical energy generated from *Utility-Scale Photovoltaic and Solar Thermal, Hydroelectric, and Wind* is based on recorded data from Feed-In Tariff (FIT) contracts and Independent Power Producers with PPAs.
- Starting on January 1, 2015, energy efficiency and solar water heating amounts cannot be applied toward meeting the RPS, thus these amounts are not included.

Figure D-4 depicts the various renewable resources on our five electric power grids, and their combined RPS attainment, as of December 31, 2015.

Consolidated RPS of 23.2% for 2015

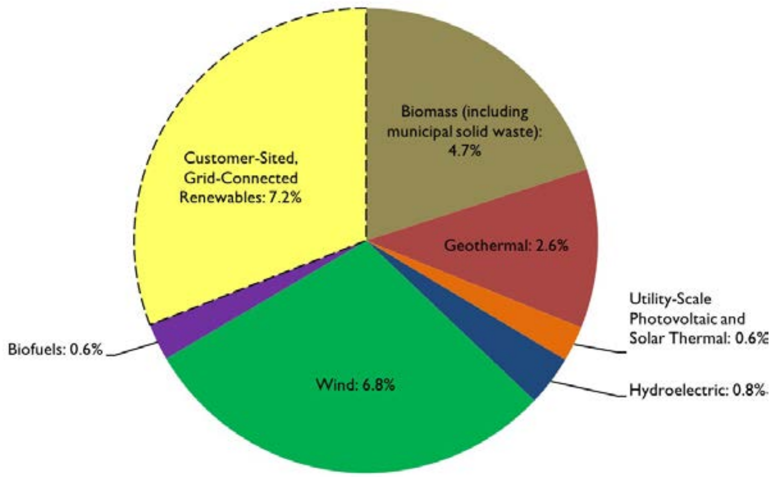

Figure D-4. Consolidated RPS of 23.2% for 2015

Note: Adding the individual percentages derives a total of 23.3% which is accounted for through rounding of the single digit decimals.

For the sake of comparison, our consolidated RPS in 2013 without energy efficiency measures was 18.2%; in 2014, our consolidated RPS climbed to 21.3%—an increase of about 17%. At the end of 2015, our consolidated RPS is 23.2%—an increase of 9% over 2014.

IMPACTS OF VARIABLE GENERATION AND DER ON OUR GENERATION FLEET

The operation of our power systems has become increasingly complex and challenging due to the impacts of variable wind and a rapid increase in distributed generation, most of which is variable solar photovoltaic (PV). Current levels of variable generation have already led to changes in how existing generation assets are used. Continued additions of variable generation will lead to further changes.

There is increased offline and deep cycling, requiring a greater number of unit commitment decisions. In general, there are fewer conventional plants online to provide frequency and voltage regulation, ramping, short circuit current for fault detection, and system inertia. This results in less stable frequency and system security issues.

As distributed PV generation increases, the minimum daytime load demand continues to decrease. Now that the PV generation levels are causing the minimum demand to approach the minimum load capability of the baseload units typically online, the use of fossil generation must change to accommodate this increased DG-PV. The conventional plants increasing serve a role of supplementing the production of variable renewable resources (wind and solar) to meet demand.

The Effects of DG-PV on Demand

The impact of increased distributed solar has been to change the net demand served by our generators. The evening peak still is the largest peak and remains at sunset. However, the daytime demand is highly variable due to the impact of distributed solar. During high PV production, the daytime demand approaches and in some cases is lower than the nighttime minimum and will decrease further with additional solar PV.

Figure D-5 (created four years ago) depicts this demand evolution using average demand curves over a year period for Hawaiian Electric. Starting in 2011, noticeable changes began to appear to the typical daily demand curve shape (frequently referred to in the industry as the "duck" curve) because of the proliferation of rooftop PV systems. Two years ago, we anticipated the typical demand curve to match the dotted blue line (labeled "2015"). Today, however, we are experiencing a demand curve that more closely matches that of the dotted light blue line (labeled "2017"). In other words, the evolving demand curve is moving faster than we initially projected. This quickening pace has stretched the daily responsibilities of our system operators, making their efforts to maintain a stable, reliable grid much more challenging.

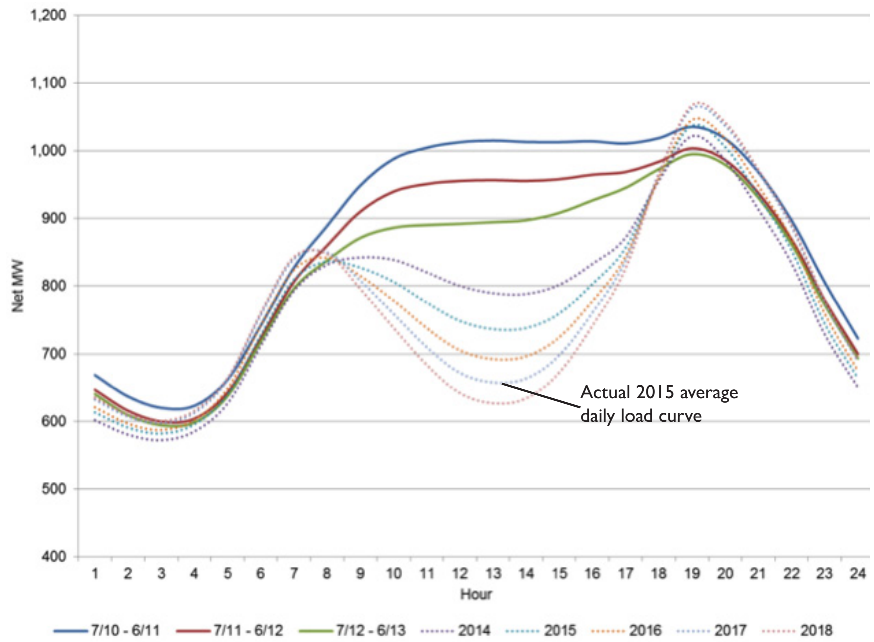

Figure D-5. Evolving Demand Profile from DG-PV Growth

These demand curves represent annual averages. In actuality, demand during the middle of the day is unpredictable. Some days demand is low because DG-PV generation is higher; other days demand is high because DG-PV generation is low. The chart below shows recorded data for Hawai'i Electric Light showing this variability for a week period comparing 2011 through 2016.

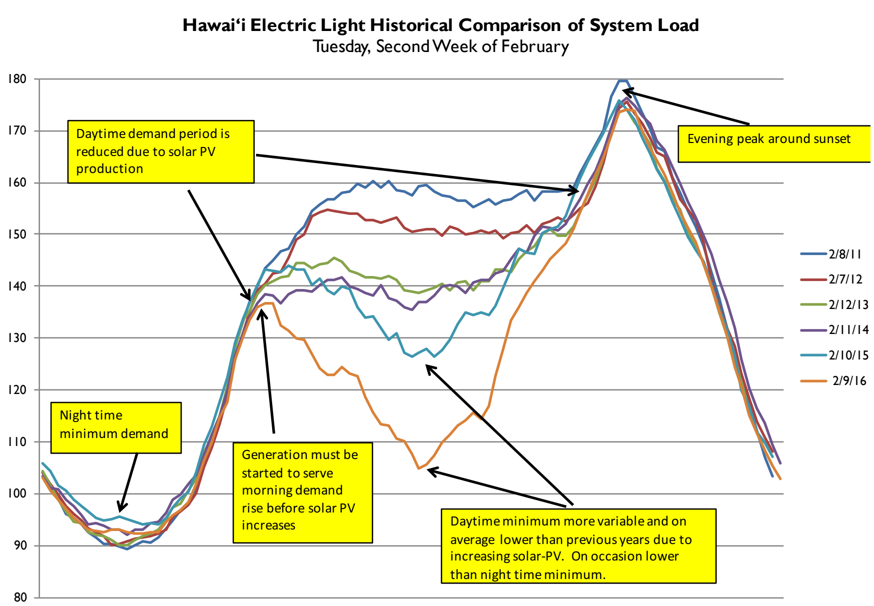

Figure D-6. Hawai'i Electric Light Weekday System Load Comparison

The vast majority of the existing PV systems are installed through the Net Energy Metering (NEM) program, a Standard Interconnection Agreement (SIA), as well as through the Customer Self Supply (CSS) and Customer Grid Supply (CGS) programs. These behind-the-meter systems offset the customer's energy use. Most residential loads are low during the day when DG-PV generation is at its highest, thus much of this generation is exported to the electric grid where it must be accommodated by reducing other generator output. At present, the operator can neither directly monitor nor control nearly all of these systems.

The existing variable distributed solar creates challenges with maintaining system frequency. In the future, as distributed generation increases, it will be necessary for distributed resources to contribute to balancing supply and demand to preserve system operability and reliability. This will include provisions for system control and local response to frequency. For the present, the other generation sources on the system, including controllable utility scale renewable energy, must be reduced to accommodate the distributed solar.

Impact of Variable Generation on System Balancing and Generator Use

To ensure a functional and reliable grid, a balance between supply and demand must be maintained. The balance is measured by the electric frequency—the system is balanced when very close to 60 Hz (cycles per second).

The impact of higher levels of variable generation has affected our systems in the following ways:

- Variable energy displaces output from conventional plants. This has led to increased operation at low output for generators. It has also led to offline cycling of some units previously operated continuously.
- The net demand to be served by generation is more difficult to predict. The existing fossil generation resources provide energy to meet the remaining demand after the solar PV and wind production. Even with state-of-the art forecasting, a great deal of uncertainty exists about the amount of variable energy available over the next several hours.
- There is an increasing need for frequency response and ramping. The variable output of wind and solar PV creates a frequency imbalance that must be offset by other generation. With existing conventional units displaced to accommodate variable renewable energy, there are fewer generators online to respond to changes in variable solar and wind. Because of these combined actions, faster response for frequency control (fast primary frequency response and ramp rate) is required.

On afternoons with high DG-PV generation, demand could fall below the minimum output that the system can support—that is, below the minimum demand of the generators that must remain online to keep the system operable. This potential can only be mitigated by adding new resources, and may include a combination of variable generation controls and frequency response, new resources to increase demand on the system (such as storage), or adding resources that allow reliable operation with reduced or no minimum online generation.

Generator Modifications and Characteristics

To manage the changes to the system due to variable generation, the following are areas of change to existing plants and desired characteristics for new generators:

Increased ramping capability. With increasing variable generation, the required ramp rates may exceed the capability of existing units. Many of the available options for replacement generation have superior ramping capabilities and would provide more flexibility to react to variable energy ramps in output.

Increased dispatch range, reduced minimum dispatch limit. With increasing minute-to-minute balancing and fast ramping requirements, the ability of generators to operate a lower minimum dispatch levels is desired.

Capable of routine offline cycling. As renewable energy facilities displace conventional plants, offline cycling may be required to avoid excess energy. Some plants historically operated continuously are cycled offline daily or operated only for peaking periods. Other facilities have been removed from service. Measures must be taken to preserve the generator and enable its return to service in a reasonable time if needed.

Faster startup times. Fast startup times help manage the uncertainty in net demand forecasts by being able to adjust the online generation for changes in variable generation and supplementing resources for unexpected reductions in variable generation output. To offset from potential down ramp events, offline generation will ideally have quick start times (less than 10 minutes to start and reach full load) and low startup costs. Conversely, sometimes the variation from variable generation may be upward. In these cases, it is ideal that online generation can be shut down quickly and later quickly restarted if necessary. This flexibility to start and stop quickly many times daily at low cost is not a characteristic typical of our existing firm generation fleet.

Increased capabilities from variable generation. The variability of wind and solar energy sources increases the burden on other generation to provide frequency response and ramping. Modern wind and solar facilities have the capability to lessen these impacts if properly designed. Newer wind and inverter-based generation resources, if properly designed, can provide some frequency response and limit potential ramp rates. By utilizing these capabilities, variable resources place less of a demand on other resources on the system. The capability to control resources is also a critical factor as distributed generation provides a significant amount of the total energy on the systems.

There are significant challenges in managing the system with existing generation resources under the changing use requirements. Reducing minimum load has some advantages over on-off cycling. When online and at minimum loads, the units still provide necessary services to the system: inertia, voltage regulation, frequency regulation, short-circuit current, some ramping capability, and some ability to respond to system disturbance.

Reducing minimum load requirements:

- Reduces thermal stress to the turbine rotor and casing.
- Reduces generation to a minimum to integrate more renewable energy.
- Provides system inertia.
- Provides short circuit current in the event of a system fault.
- Provides MVAR (reactive power) capacity and voltage support.
- Enables a unit to load to full capability faster than a unit startup.

Compared to on-off cycling, low-load operation allows for quicker return to full load capability and lower long-term maintenance costs.

A disadvantage is that at some loads, the units have limited ramping capability until at or above its normal operating range. Figure D-7 shows the ability of a Hawaiian Electric unit to reach full load from its old minimum compared to the 5 MW minimum.

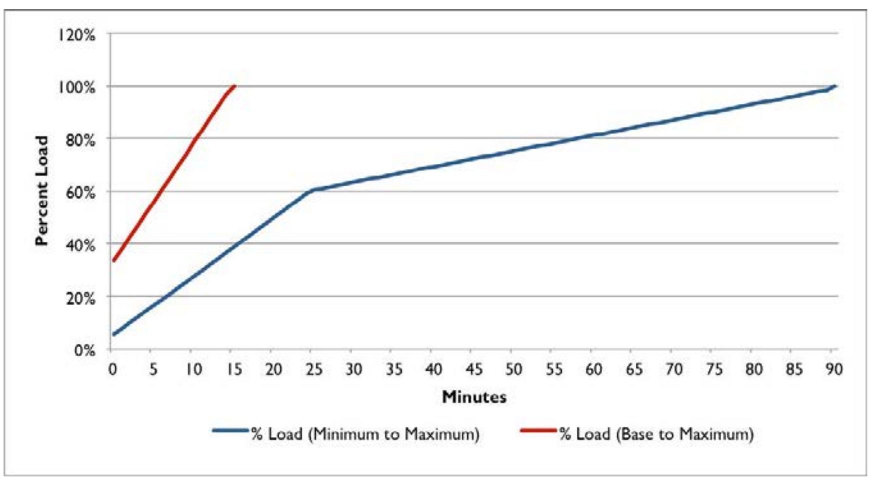

Figure D-7. Ramp Time from Minimum and Base Loads to Full Load: Hawaiian Electric

Increasing renewable energy can also require cycling units off and on. However, many of the larger, lower-cost conventional units are designed for continuous operation, not cycling. This option, therefore, creates much concern about reliably, especially when combined with running the units at low load levels. Startup problems can delay the time a unit is brought on and thus cause generation shortfalls. Any time a unit not designed to cycle is frequently cycled offline and online, these startup risks become inherent. Cycling these units also increases wear and tear; over time, they require more maintenance. Offline cycling on a routine basis is not feasible for all existing generators. When units are taken offline for extended periods, preservation measures are required, including routine inspection of the preservation equipment, to ensure the generators remain in good condition and ready to return to service when needed.

Evolving Dispatch of Our Cycling Units

The effect of changing use of our generating units has already been very noticeable. Utility-owned generation has experienced increased offline cycling, lower capacity factors, and reduced average operating load. Generators have been removed from service for periods of time which required measures to preserve the units and return them to service in a reasonable time when need to serve demand or when cost changes made these units economical.

Long-Term Reliability Issues

Long-term reliability issues include starting units to operating levels, safely, quickly, and securely, to meet demand. The more we push these units beyond their intended design, the more problems are likely to surface. This might already have been the case with Waiau 3.

Only time will tell how the effects of our changes affect reliability.

Changing Use of Existing Generation

Hawaiian Electric, Hawai‘i Electric Light, and Maui Electric have expanded the capabilities of the existing generating units to support the changing electric system. These modifications, however, required tradeoffs.

Low loads and increased cycling of these units, while successful, increases maintenance costs, increases the potential for unplanned outages, and decreases their normal operational efficiency.

In 2012, the National Renewable Energy Laboratory (NREL) published its report, Power Plant Cycling Costs, which based much of its results on Equivalent Demand Forced Outage Rates (EFORd). The EFORd is a measure of the probability that a firm generating unit will not be available due to forced outages or deratings during a demand period. That report demonstrated higher forced outage rates that result from cycling operation (Figure D-8), and concluded that costs associated with cycling and increased load-following events would drive future maintenance costs higher.

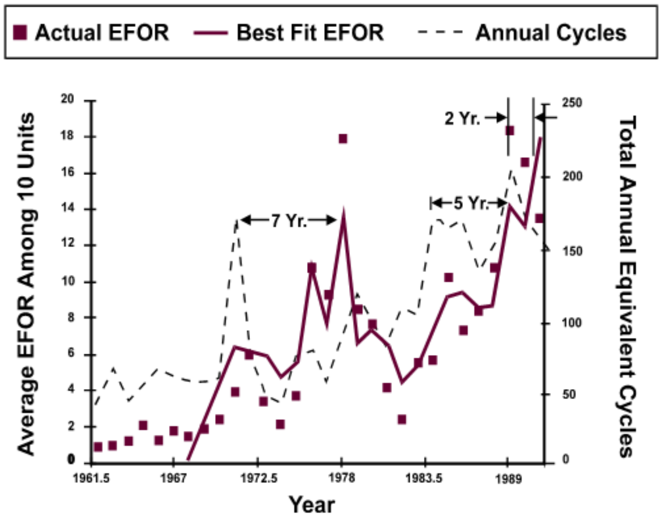

Figure D-8. Forced Outage Rates from Cycling: U.S. Averages

We understand the impact on units from low loads and increased thermal cycles. As a result, we are optimizing procedures and reviewing practices and options to minimize cost and maximize reliability. We expect to review options to reduce or minimize cycling-related damage.

E. New Resource Options

To develop our December 2016 updated PSIP, the Companies carefully considered a set of new resource options in our analysis. These options and related assumptions provide planners with a set of consistent new resource options from which to choose when selecting a future optimal portfolio of generation resource additions. In other words, this information is a planning tool. These new resource assumptions, however, are not intended to provide rigid baselines for new project developers to obtain Power Purchase Agreements (PPAs).

We developed these assumptions from the best publically available information, independently reviewed by the National Renewable Energy Laboratory (NREL), shared with the parties to Docket 2014-0183 beginning in February 2016, and continuously vetted against new information available (including input from the Parties). In the end, we reviewed all input assumptions, retaining some and adjusting others as appropriate.

We made every attempt to ensure these assumptions reflect "real world" conditions. Proposals for specific projects, however, might result in different values for any of the PSIP assumptions; these variances would be based on specific site conditions, technology vendors utilized, developer profit requirements, and many other variables. Competitive procurement of resources will ensure the cost effectiveness of the resource addition and selection of the best available resources.

To avoid speculation, our December 2016 PSIP analysis required that resource options considered be either commercially available today or reasonably available within the study period. Our near-term Action Plans commit only to resources that are fully commercial today. We believe the best interests of our customers are served by not expecting them to underwrite the risks associated with technologies that are not commercially available today.

In the longer term, however, this PSIP can consider certain resource options (for example, offshore floating platform wind) that appear poised to become commercially available within the next ten to fifteen years. Other emerging options (for example, hydrokinetic energy) appear to be at least a decade or more away from commercialization. As our Action Plans include flexibility to incorporate technology change, we fully expect that future long-term resource planning efforts will consider resource options that are not commercially available today.

In turn, all Parties must consider the types of renewable resources, their cost, and current and future availability that can play an integral role in achieving our 100% renewable energy goal. We are and will always be open to new technologies as they are developed into commercial products. In the meantime, our near-term Action Plans maximize the resource potential currently available from commercially available renewable resources: solar PV, wind, DER, and "firm" renewables.

AVAILABLE GENERATION OPTIONS

For the December 2016 updated PSIP analyses, we have taken a "clean sheet" approach in developing new resource options. In developing this new set of assumptions, we are mindful of the Commission's concerns expressed in Order No. 33320 about the results from our 2014 PSIPs:

> …appears to rely on the utilization of renewable resources with relatively high costs and unproven resources with uncertain feasibility.[1]
>
> …the technology cost assumptions utilized by the Hawaiian Electric Companies in the PSIPs also appear conservative" and "…do not appear to accurately reflect current cost trends…[2]
>
> …the amounts and types of renewable resources that are considered in the PSIP analyses appear to be inappropriately limited. Generally, the Hawaiian Electric Companies' criteria for exclusion of resource technologies from consideration in the economic analyses based on the state of commercial readiness appear over-restrictive. The Companies have categorically excluded generation technologies with a Commercial Readiness Index ("CRI") lower than five. This excludes technologies with a CRI of four, which are technologies in full-scale commercial use and have "publicly verifiable data on technical and financial performance."[3]

While technologies with a CRI Level 4 are in full-scale commercial use and have "publicly verifiable data on technical and financial performance", the full description of

1 Order No. 33320, at 80.
2 *Ibid.*, at 84–85.
3 *Ibid.*, at 83.

CRI Level 4 also included criteria related to the ability of these technologies to be financed. In particular, CRI Level 4 technologies "…may still require subsidies" and that there is "…interest from debt and equity sources" that "…still [require] government support." We chose to consider technologies in the 2014 PSIPs based on the ability of the technology to receive financing without the need for subsidies, and to avoid relying heavily on technologies that have "high costs and uncertain feasibility". The 2014 PSIPs also stated that "…this planning assumption is for the PSIP analyses only, and does not affect our intent to thoughtfully consider specific projects that include emerging technologies. In other words, we welcome generating technologies not considered in the 2014 PSIPs that are proposed in responses to future request for proposals (RFP) for any of our power systems."[4] We reiterate that intent here.

New Grid-Scale Resource Assumptions

For the December 2016 PSIP analysis, we use multiple sources of forward curves for the capital cost of new generating technologies and new energy storage technologies. Figure E-1 shows the projections of per unit capital costs expressed in 2016 real dollars per kW. The data underlie the nominal dollar assumptions used in the PSIP analysis. The constant dollar projection is a useful way to portray the expected future cost trends of various electric power generation technologies.

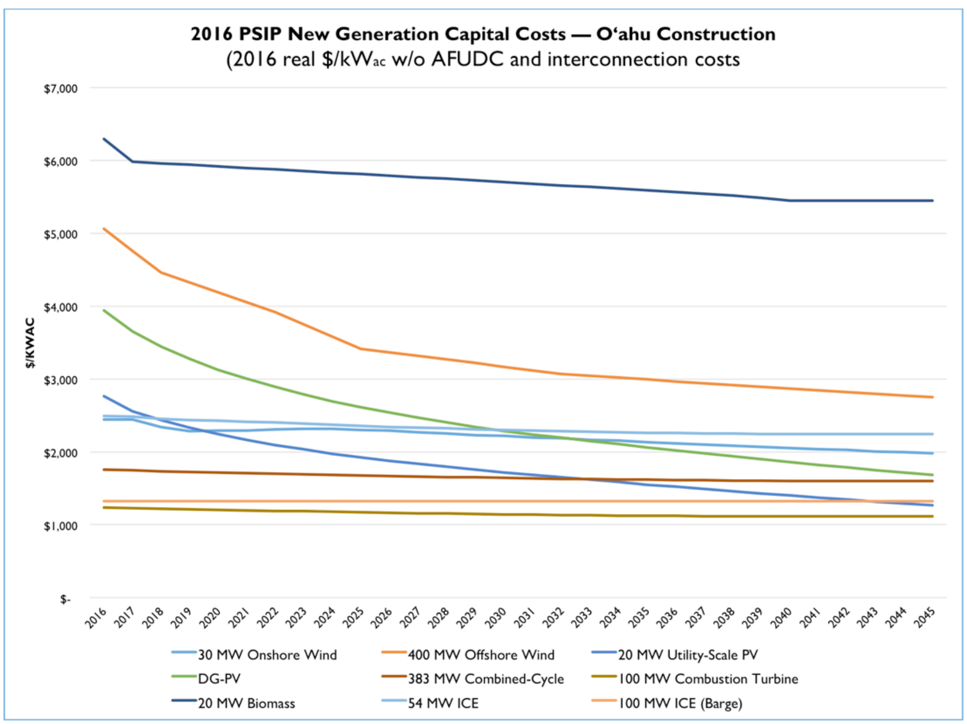

Figure E-1. December 2016 Updated PSIP New Generation Resource Capital Costs—O'ahu

[4] Power Supply Improvement Plan, filed August 26, 2104, at H-1.

Data Sources

In our analyses for this December 2016 PSIP, we have completely reworked the resource technologies and cost assumptions, starting with a review of current literature and data sources including:

- National Renewable Energy Laboratories' (NREL) *2015 Annual Technology Baseline (ATB)* spreadsheet (July 2015).[5]
- *Lazard Levelized Cost of Energy Analysis – Version 9.0* (November 2015).[6]
- Energy Information Administration's (EIA) *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* (April 2013),[7] used primarily as guidance for regional cost adjustments.
- Electric Power Research Institute (EPRI) *Technology Assessment Guide* (2013-2015 data sets), a proprietary[8] database of power technology costs and performance.
- Various proprietary reports published by IHS Energy in 2015 regarding cost trends related to solar PV, wind, and energy storage technologies.
- *Gas Turbine World 2014–15 Handbook*, a publication that provides power plant prices, price trends, and performance data for combustion turbines and combined-cycle plants.
- RSMeans data, which publishes proprietary indices regarding materials, labor, and productivity for more than 900 cities in the United States and Canada, including Honolulu and Hilo.
- Our internal data and estimates for the cost of internal combustion engines (ICE), including the actual budgeted costs for the Schofield Generating Station (as proposed in Docket 2014-0113 and reduced to reflect favorable movement in foreign exchange rates) and a vendor quote for the 100 MW ICE power barge proposed for O'ahu.
- Our internal estimates of system interconnection costs for resources of various sizes (including the cost of connecting to the grid). These estimates exclude costs associated with system upgrades that might be required to accommodate a specific project.

In our response to Information Request PUC-HECO-IR-44,[9] we discussed our development of new resource assumptions in greater detail. As a public document, this information was readily available to the Parties; nonetheless, we posted our response on our collaborative WebDAV ftp site and emailed it to Parties who sent requests.

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5 The NREL ATB spreadsheet is available at: http://www.nrel.gov/analysis/data_tech_baseline.html.

6 The Lazard analysis is available at: https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf.

7 The EIA report is available at: http://www.eia.gov/forecasts/capitalcost/.

8 "Proprietary" means that the materials, analysis, and data are trademarked, privately-owned, private, patented, or otherwise exclusive to the party producing the information. Generally, any party willing to pay for a license can obtain the information. We are bound by the terms of the license or right agreement when we use these resources. This is a common commercial practice.

9 Docket 2014-0183, PUC-HECO-44, filed on March 1, 2016.

New Resource Input from the Parties

As directed, beginning in November 2015, we continually solicited input from the Parties regarding new resource assumptions and costs. Several Parties provided input.

Paniolo Power replied first with partial information regarding the costs and operating characteristics of grid-scale wind and pumped storage hydroelectric (PSH), then provided a more complete set of information. Their PSH data, as jointly agreed, was essentially the same as ours, and site-specific information for wind was provided under protective order.

Hawai‘i Gas provided information about LNG. After adjusting their data to the same format as our LNG data, together we found that both sets were essentially similar. Hawai‘i Gas commented that their expected volume in 2020 will be 300,000 tonnes per annum (TPA), excluding the volumes of the Kalaeloa Partners LP power plant. Given Hawaiian Electric's estimated volume of 600,000 for O‘ahu, Hawai‘i Gas requested that LNG pricing at the 900,000 TPA volume be evaluated.

Ulupono representative Dr. Matthias Fripp provided information about the theoretical maximum potential for grid-scale solar PV and grid-scale wind resources on O‘ahu. These potentials expanded on the results from a similar NREL study.

SunPower provided grid-scale solar PV capital costs from a third-party source, however these costs did not readily adjust for Hawai‘i installation. After a series of productive interactions, together we determined that both sets of data were essentially similar.

In September 2016, HREA submitted biomass fixed O&M and fuel cost assumptions (on behalf of Hu Honua who is not a Party) that were higher than our assumptions. We had already adjusted our biomass assumptions in June 2016, which we used in our modeling analysis.

See "Input Incorporated into Our PSIP Update" in Appendix B: Party Commentary and Input for detailed discussion of our interactions with these Party members, the results of these discussions, and how they affected the input assumptions in our modeling analysis.

Several Parties suggested nascent technologies as resource options (specifically ocean wave power and hydrogen storage). No Party, however, proffered specific capital costs, operating costs, performance specifications, or specific justification that such options were commercially available or could be reasonably expected to be commercially available. Indeed, our own research concluded such technologies are not viable resource options, and thus were not considered in our planning.

Developing the Resource Cost Assumptions

We pursued several avenues to develop and then synthesize resource costs into a common set of assumptions for the December 2016 PSIP update analysis. These avenues included data sources, NextEra Energy, and NREL.

We researched and reviewed the most current data sources possible—one such source is the NREL ATB database. The NREL ATB data source provides a publicly available source of the forward curves for capital costs, and operations and maintenance expenses for several different power generation technologies. We combined this data with the EIA's 2013 *Updated Capital Cost Estimates for Utility-Scale Electricity Generating Plants* Honolulu-specific information regarding locational adjustments (by technology) to adjust the NREL ATB data for Hawai‘i. We adjusted the cost data using 2016 dollars as the base year by converting all cost information from real dollars to nominal dollars using a 1.8% inflation and escalation rate (because nominal dollars are used to evaluate various cases in our economic analysis).

We worked with NextEra Energy to develop some resource assumptions that have been used in both our April and December 2016 updated PSIP. NextEra Energy has extensive experience as a developer, owner, and operator of wind power, solar PV projects, concentrated solar power (CSP) projects, gas-fired generation stations, and bulk energy storage projects. NextEra Energy used IHS Energy's proprietary research reports to develop initial cost assumptions for certain resources, including solar PV and energy storage. IHS reported information for developing renewable resources and energy storage for California, and also provided forward curves for various resources. The California reference was adjusted to a Hawai‘i value based on the RSMeans' city indices for materials, labor, and productivity. NextEra Energy then compared the results of the Hawai‘i-adjusted data to its own experience in developing and operating some of the technologies considered, including projects in Hawai‘i. We collaborated with NREL to derive the new resource assumptions based on independent data sources. In addition, we contracted with an outside consultant, HD Baker and Company, to compile these resource assumptions to assure their consistency and objectivity. The result is a set of cost values for the various technologies that reflect independent evaluations and actual experience. All prices were adjusted for Hawai‘i by applying a 4% adder for Hawai‘i General Excise Tax to the base price.

New grid-scale solar PV and grid-scale wind projects are eligible for federal and state investment tax credits (ITC) for residential (mostly rooftop) and commercial installations. (The commercial business that installs, develops, or finances the project claims the tax credit). In 2016, the tax credit is highest; the ITC slowly dwindles over the next five to seven years.

Federal tax credits directly reduce the installer's federal taxes; state tax credits directly reduce the installer's state taxes. Until the end of 2018, installers also benefit from an accelerated depreciation schedule. For example, a project installed in 2016 can depreciate 50% of the project cost (after the tax credit) in the first year of a five-year depreciation schedule. Table E-1 compiles the various federal and state tax credits used as input assumptions for the December 2016 PSIP analysis.

PSIP Investment Tax Credits Assumed in December 2016 PSIP Update				
	Grid-Scale Solar PV and DG-PV		*Grid-Scale Wind*	
Year End	Federal ITC	Hawai'i State ITC	Federal ITC	Hawai'i State ITC
2016	30% + 50% Bonus Depreciation	35%	30% + 50% Bonus Depreciation	35%
2017	30% + 40% Bonus Depreciation	35%	30% + 50% Bonus Depreciation	35%
2018	30% + 30% Bonus Depreciation	30%	24% + 40% Bonus Depreciation	24%
2019	30%	30%	18% + 30% Bonus Depreciation	18%
2020	26%	26%	12%	12%
2021	22%	22%	0%	0%
2022 and after	10%	10%	0%	0%

Notes: Federal investment tax credits are pursuant to an extension included in the 2015 Omnibus Appropriations Act (P.L. 114-113). Hawai'i State investment tax credits are assumptions based on the Federal ITC and are assumed to phase out in-line with any Federal phase out.

Table E-1. Solar PV and Wind Investment Tax Credits

We retained NREL to independently and objectively review the assumptions synthesized through this processes. NREL filed two reports on their analysis. NREL found our assumptions to be consistent with their own database and other third-party sources. We discuss specifics of their conclusions Grid-Scale Resource Assumptions on page E-18. (Appendix F contains the actual NREL reports.)

Generation Technologies Considered

For our December 2016 PSIP update, our near-term action plans rely only on technologies that are commercially available today. Those technologies include grid-scale solar photovoltaic, distributed solar photovoltaic, onshore wind, combustions turbines, combined-cycle plants, internal combustion engines, geothermal, waste-to-energy, microgrids, solar photovoltaics plus storage combination, and biomass as a fuel. We consider this to be in the best interest of our customers.

For the longer-term, we also considered floating platform offshore wind, which appears likely to achieve commercialization within the next decade. Several promising hydrokinetic energy technologies, while intriguing, were not considered because they are not currently commercial available. These technologies require substantial amounts of subsidies and investment in research, development, and engineering. They are, at least, two decades or more away from commercialization. We will continuously monitor developments with these technologies, and as new resource options become commercially available, we will likely consider such technologies in future resource plans.

We developed our December 2016 updated PSIP to serve as the basis for actionable, near-term decisions regarding approvals for RFPs to solicit resources to meet capacity needs, applications for capital expenditures related to power supply and energy storage projects, and applications for PPA approvals. In addition, we developed our December 2016 updated PSIP to be flexible over the long-term to accommodate technology and cost improvements in existing technologies, and to accommodate the commercialization of transformational technologies that might become available. It is our best understanding that this prudent and reasonable philosophy benefits our customers, and best achieves our state's renewable energy goals.

Our choice of technologies for the December 2016 updated PSIP is a planning assumption, and in no way is intended to limit or discourage proposals for other technologies. Such proposals, however, must exhibit the following attributes:

- Sound engineering design concepts.
- Commercial availability of the technology from a reputable vendor who stands behind the performance and servicing of the technology (including all balance of plant items) over its useful life.
- Demonstrated financial feasibility of the project employing the technology, including its benefits to customers, taking into account system needs and integration costs.
- The ability of the project sponsor to demonstrate the financial wherewithal and technical capabilities to successfully finance, construct, and operate the project employing the technology.

To meet our goals for the December 2016 updated PSIP, we limited new resource analysis choices to these technologies.

Grid-Scale Solar Photovoltaic

Solar PV technology is mature. Current forecasts are characterized by continuing modest declines in capital costs and incremental improvements to the technology. Multiple grid-scale solar PV projects have been placed in service in Hawai‘i, and more are on the way. We have significant experience with solar PV technology in the Hawai‘i market, as do many IPP project developers and capital providers.

The PSIP assumptions reference fixed-tilt (versus single-axis and multi-axis tracking) systems. The December 2016 PSIP update utilizes capacity factors and output profiles for grid-scale solar based on historical experience with existing grid-scale solar PV systems. Costs for solar PV systems are typically expressed in dollars per watt of the total output of the PV system panels: direct current (DC) power. The ratios of DC output to (usable) AC output in grid-scale solar PV projects typically ranges from 1.1–1 to 1.5–1. Both the reference plant capital cost and the NREL resource analysis assume a 1.5 to 1 DC to AC ratio. This higher ratio typically allows projects to achieve higher capacity factors since more PV panels boosts output over the shoulder periods around the time of peak irradiance.

In response to stakeholder input, the December 2016 PSIP update utilized different sizes of PV projects, with corresponding capital cost adjustments for smaller projects (that is, smaller PV projects have a higher per unit cost).

Distributed Solar Photovoltaic

The PSIP cost assumptions and future cost trends for DG-PV are based on the same source data as the grid-scale solar PV. These solar PV costs were adjusted for Hawai‘i and compared to actual costs for residential PV systems based on contact with vendors. The cost of DG-PV is expected to decline (in real dollars) over the study period. The net capacity factor for DG-PV is assumed to be 18.4% for O‘ahu, 16.9% for Hawai‘i island, 17.8% for Maui, 16.3% for Lana‘i, and 19.8% for Moloka‘i.

Onshore Wind Power

Onshore wind projects employ a mature technology. Wind power trends are characterized by modest decreases in per unit capital cost (in real dollars), modest performance increases, and substantial improvements in the size of commercially available single wind turbines. Over 200 MW of wind capacity are operating in our service areas, almost all of it owned by independent power producers (IPPs). We have significant experience with onshore wind technology in the Hawai'i market, as do many IPP project developers and capital providers.

Wind projects on O‘ahu, Maui, and Hawai‘i Island all exhibit significant economies of scale because of the intensive mobilization effort (for example, heavy cranes, equipment to move towers, and turbines from port to the site location). The cost assumptions used in the December 2016 updated PSIP reflect these economies of scale.

Because of the limited harbor facilities on Moloka‘i and Lana‘i, the cost of mobilization to install what would likely be a single larger scale wind turbine (that is, the current market sizes are in excess of 2 MW) would be prohibitive. Instead, wind project assumptions were developed for 100 kW turbines that could be installed without large cranes and the resulting high mobilization costs.

The net capacity factor modeled in the reference plant was 22.7% for O‘ahu, 54.4% for Hawai‘i Island, and 51% for Maui, Lana‘i, and Moloka‘i.

Floating Platform Offshore Wind

The April 2016 updated PSIP plans for O‘ahu incorporated a substantial amount of floating platform offshore wind. Recent activities by the Bureau of Ocean Energy Management (BOEM) towards developing leases for offshore wind blocks in Hawai‘i, and interest from at least three different developers, led the Companies to commission an assessment of offshore wind. See “Offshore Floating Platform Wind Energy” in Appendix H: Renewable Resource Options for O‘ahu for a discussion of the commercial and technical status, development risks, and costs of this renewable resource.

Combustion Turbines

Modern combustion turbines (CTs) are the “workhorse” of electric utility systems around the world. Essentially jet engines coupled to a generator, CTs can be designed to burn a variety of fuels including fuel oil, naphtha, and natural gas. CTs are characterized by relatively low capital costs, modest efficiency (heat rates of 10,500 Btu per kWh), high reliability, and relatively short installation lead times. Smaller CTs typically are less efficient than larger machines (heat rates as high as 18,000 Btu per kWh for small microturbines). CTs are a mature technology with projected flat capital costs (in real dollars) and continued small incremental performance improvements over time.

CTs have significant operating flexibility with fast-start capability, fast ramping, and a high level of variability when spinning. CTs are typically used as peakers (when capacity is required to meet short duration peak demands). Typical annual capacity factors for CTs are less than 20%, sometimes significantly less. CTs can play an important role in integrating variable renewables by providing capacity and energy when variable renewable generation wanes.

Several very large, well-capitalized international vendors provide CTs in a variety of sizes. Each of these vendors has extensive supply chains for parts and service. Their capabilities are supplemented by numerous specialized O&M service firms and after-market parts suppliers. The Companies, as well as most utilities, have a vast amount of experience with CTs, as do many IPP project developers and capital providers.

Combined-Cycle

Combined-cycle power plants employ CTs that add a heat recovery steam generator (HRSG). HRSGs take the exhaust heat from one or more CTs, “recover” the thermal energy that otherwise would go to waste, and produce steam. The steam is then used to turn a turbine coupled to a generator. Combined-cycle plants typically exhibit the greatest efficiency technically possible with thermal generation. Heat rates for modern combined-cycle plants operating at high capacity factor as low as 7,000 Btu per kWh. The reliability of combined-cycle plants is high; as such, they tend to be used as baseload and cycling generation.

Combined-cycle power plants are a mature technology, with flat projected capital costs, and incremental performance improvements over time. Like CTs, combined-cycle power plants are used by utilities and IPPs around the world. Combined-cycle plants are procured and serviced through a well-established and mature supply chain. Financing for combined-cycle plants is readily available in the capital markets.

There are various configurations of combined-cycle plants; chief among them are a single-train combined-cycle (STCC), a dual-train combined-cycle (DTCC), and a 3x1 combined-cycle (3x1 CC). We own and operate three DTCC plants: one at the Keahole plant on Hawai‘i Island and two at the Ma‘alaea plant on Maui. The Hamakua Energy Partners (HEP) plant on Hawai'i Island (which the Companies filed an application in Docket 2016-0033 to acquire) is also a DTCC plant utilizing the same make and model of combustion turbines installed at both Keahole and Ma‘alaea.

The 383 MW 3x1 CC proposed in our April 2016 PSIP update has been replaced with a proposed 152 MW STCC configuration for this December 2016 PSIP update.

Internal Combustion Engine

Internal combustion engine (ICE) generation couples an internal combustion engine with a generator. Modern ICE generators are in widespread use throughout the world. They are the dominant technology employed in DG applications; however, they are routinely found in grid-scale applications as well.

ICE generation has relatively high efficiencies (heat rates of approximately 10,000 Btu per kWh) across a wide operating range (25% to 100% of full load), and rapid start-up and shutdown capabilities. ICE generation is a mature technology. Cost and performance trends into the future are relatively flat. There is a robust and competitive market for ICE consisting of several major global vendors and a handful of other players.

We are currently building a 50 MW ICE generation station at the Schofield Barracks Army Base on O‘ahu. (See "Schofield Generating Station" in Appendix D: Current Generation Portfolios for more information.) The Schofield Generating Station will provide additional operating flexibility to help manage increasing penetrations of variable renewable resources, including DG-PV. It is also designed to allow Schofield Barracks to operate as a microgrid (that is, in an "islanded" mode) providing energy security for the base.

Geothermal

Geothermal power generation relies on underground heat sources. Typically, water is injected into a well drilled into an underground high temperature pocket to create steam that is channeled to the earth's surface and used to turn a steam turbine-generator set to generate electricity.

There are two types of geothermal power plants. Flash steam geothermal plants directly utilize high temperature hot water extracted from wells to produce steam that turns a steam turbine-generator. Binary cycle geothermal plants take the hot water from wells, and pass it through a heat exchanger with a working fluid with a much lower boiling point than water, and then that fluid is used as steam to turn the turbine-generator set. Hawai'i Electric Light currently purchases electrical capacity and energy from the Puna Geothermal Venture (PGV) 38 MW geothermal power plant. PGV utilizes a binary cycle design.

A variation of the binary plant design is driving a growing sector of the geothermal development industry. Because the binary design uses a working fluid with low boiling points, it is becoming feasible to tap into much lower temperature geothermal resources that occur naturally in certain locations that are not necessarily associated with volcanic activity. Technological advancements in directional drilling allow access to deeper and "cooler" geothermal resources, while improved working fluids and innovative cooling technologies allow lower temperature thermal resources to be used in power production applications. The potential for this type of geothermal technology to be employed in Hawai'i is unknown. If that potential is proven, it could conceivably unlock geothermal energy on islands beyond just Maui and Hawai'i Island.

Because geothermal is a proven technology, it has been considered a new resource option for the December 2016 updated PSIP for Maui and Hawai'i Island. Developing new geothermal generation in Hawai'i will require extensive resource assessment through additional field research (that is, test wells), development of clear regulatory and institutional frameworks, and ultimately, permitting and construction. Because of the extensive activities necessary to develop new geothermal resources, the December 2016 updated PSIP considers geothermal potential resources only available beyond the near-term planning period.

Biomass Plants

Biomass plants can generate power in several ways. Biomass feedstock can be processed through gasifiers to produce a gas or liquid fuel that is then burned in thermal generating technologies (such as ICE, CTs, and combined-cycle plants). Biomass feedstock can also be burned directly to provide heat to create steam, which in turn powers a steam turbine-generator to produce electricity. The PSIP assumption for a 20 MW biomass plant is based on this latter direct combustion process.

We continue to explore opportunities to use locally produced energy crops for their possible contribution to renewable power generation. Various parties in Hawai'i continue to research and develop the commercial potential of test crops: cellulosic feedstock (such as bana grass), energy cane and oil seed crops (such as jatropha, sunflower, and pongamia), and eucalyptus from farms on Hawai'i Island. In addition, grown crops as well as process water waste can create biogas (a biomass fuel commercially proven in installations around the world) through anaerobic digestion.

Biofuels (another form of biomass) can be easily transported via truck containers and barges to generation sites, and substituted for liquid fuel in many of our existing units. Both biogas and biomass for power generation are economically feasible only when the feedstock is close to the power generation facility. Cellulosic crops and crop waste can serve as feedstock for anaerobic digesters to produce biogas. Our use of biogas for power would require conversion of existing generation to fire gas or new gas-fired generation. Biomass derived from energy crops, crop waste, or tree waste can be dried and pelletized to use in generating units that can otherwise burn coal. Cost-effective biomass or biogas generation using purpose-grown crops remains to be proven, but holds promise.

The January 7, 2016 announcement by A&B to cease production of sugar by Hawaiian Commercial Sugar & Company (HC&S) on Maui and transfer to a diversified agricultural model presents opportunities for further exploration of energy crops on portions of their 36,000 acres. The economics and bioenergy technologies must still be proven.

Our analysis assumed biomass fuel is obtained from on-island biomass resources. For Maui, this is based on the fact that, at one point, the HC&S power plant produced 40 MW of power from organic waste (bagasse) that is a by-product of the sugar cane operation. With the closure of the HC&S sugar operation, we assumed that a portion of HC&S's property could be dedicated energy crops. Other land outside of HC&S may also be available for growing biomass crops. On Hawai'i Island, we assumed that there is available land to support biomass plants.

We have re-examined and updated our biomass assumptions since our April updated PSIP filing. For the December 2016 updated PSIPs, the capital costs for biomass plants was derived from the NREL ATB (with adjustment factors for Hawai'i) and from an assumption that biomass fuel would cost $60 per bone dry ton (BDT) with a heat content of 7,500 Btu per pound. This results in a fuel price of $4.453 per MMBtu.[10] We also assumed a plant heat rate of 13,500 Btu per kWh. These assumptions result in an all-in cost of electricity at a 50% capacity factor of approximately $0.26 per kWh.

[10] http://www.hawaiicleanenergyinitiative.org/storage/pdfs/6_SpecificEconomicModeling_ScottTurn.pdf.

Waste-to-Energy

Like biomass plants, waste-to-energy (WTE) systems are dominated by two basic technologies: systems that involve direct combustion of the waste, with the resulting heat being used in a boiler to generate steam that drives a steam turbine-generator set; and gasification systems where the waste is broken down into a low-Btu gas that typically fuels an ICE generator.

WTE facilities tend to have very site-specific designs because the plant must be sized for the volume of the waste stream and must use the technology most appropriate for the makeup of the waste stream. For this reason, reliable capital cost and operating data for WTE plants has been difficult to find. None of the data sources we reviewed cover or routinely provide analysis for a "typical" WTE plant.

Given the volume of our waste stream, WTE plants on Maui, Lanaʻi, Molokaʻi, and Hawaiʻi Island would have relatively smaller sizes. Reliable cost data on these smaller plants is difficult to obtain. A literature search of smaller WTE plants reveals potential capital costs ranging from $4,000 to $11,000 per kW.

WTE plants exhibit economies of scale: very small plants will likely have a high per unit capital cost compared to larger plants. Considerations include the sales of electricity; the "tipping fees" received from the source of the waste; and, in some cases, the value of recycled materials pulled from the waste stream before it enters the WTE plant. Even with a given capital cost, there is the potential for a great deal of variability in determining a projected price for electricity from a WTE plant. Because of the relatively constant stream of waste, a typical WTE system is not able to substantially vary its output because of the relative narrow efficient operating range (especially direct combustion WTE plants).

The H-POWER steam plant, a 68.5 MW WTE facility in the Campbell Industrial Park owned by the City and County of Honolulu, processes up to 3,000 tons per day of municipal solid waste.[11] H-POWER is a steam plant.

In recent years, the County of Hawaiʻi and the County of Maui have proposed several waste-to-energy plants. The last two mayoral administrations in the County of Hawaiʻi both proposed waste-to-energy facilities, but both plans were abandoned. In the County of Hawaiʻi, questions arise regarding whether the waste stream is adequate to support a WTE plant.[12] Several private developers have also proposed WTE facilities on Hawaiʻi Island. There is a pending proposal from the County of Maui and a private developer to provide gas derived from municipal waste landfills to fuel existing Maui Electric power plants.

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11 http://www.covanta.com/facilities/facility-by-location/honolulu.aspx.

12 http://bigislandnow.com/2014/04/22/big-island-rubbish-enough-to-go-around/.

We will continue to work with the communities and stakeholders on WTE proposals that can help with municipal solid waste disposal issues and provide benefits to electricity customers. Should this technology become more commercially viable and demonstrate the ability to be financed without substantial subsidies, we will reconsider including WTE generation as an option in future resource plans.

Microgrids

The U.S. Department of Energy defines a microgrid as "… a group of interconnected loads and distributed energy resources (DER) with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid (and can) connect and disconnect from the grid to enable it to operate in both grid connected or island mode."[13]

Microgrids can be developed for a number of different purposes across a spectrum of uses. At one end, a military installation or data center would require an extremely high level of reliability, thus connecting the microgrid to the surrounding power grid, while retaining the option of operating the microgrid isolated ("islanded") from the grid. An example is the Schofield Generation Station currently being constructed.

At the other end, an owner might want to become completely self-sufficient by supplying all of their power from the microgrid, disconnected from the surrounding power grid. The cost to operate this isolated microgrid on par with current utility rate depends on the level of reliability desired by the owner (for example, no generation while the microgrid is out for an unplanned or maintenance outage), installation and maintenance, storage, and control systems.

A microgrid can consists of something as simple as distributed generation (for example, internal combustion engines, combined heat and power systems, solar PV, or distributed wind), energy storage systems, demand-side management systems, and a control system that, in effect, creates a balancing area within a defined set of loads. Microgrids can also incorporate energy storage and demand side management systems. Microgrids can operate interconnected with the larger utility system, or they can operate in an islanded mode.

Combined with utility time-based rate programs (such as time-of-use rates, dynamic pricing, and critical peak pricing) and demand response programs, sophisticated microgrid control systems allow microgrids to "call" power from the grid when it is economically advantageous to do so, and "put" power to the grid in response to DR program price signals.

We believe that microgrids can provide additional flexibility to our power grid, especially from customers with critical loads who can justify the costs of providing

[13] https://building-microgrid.lbl.gov/microgrid-definitions.

higher reliability. Proposals for microgrids that aggregate multiple customer loads raise numerous issues (such as cost allocation, rate design, and stranded costs) that are beyond the scope of the December 2016 updated PSIP. We will evaluate microgrid proposals case by case.

Solar PV Plus Storage Combination

A combination of grid-scale solar PV and BESS can create a "dispatchable" renewable resource. With the performance and cost improvements of BESS technologies, this combination could become a useful tool for achieving our RPS goals.

In 2015, Kauai Island Utility Cooperative (KIUC) announced its intent to develop a project with 17 MW of solar PV combined with a 13 MW/52 MWh (four-hour duration) BESS system.[14] This project will allow KIUC to store solar energy during the DG-PV "valley" of the daily demand curve, and then provide that energy later in the day and evening to serve the daily peak demand. We have met with the developer of the Kauai project and discussed potential applications for the technology in our service areas. We anticipate that future solicitations for new resources might result in proposals for this combination of technologies.

Concentrated Solar Thermal Power

Concentrated solar thermal power (CSP) is a rapidly advancing commercially available technology; the installed base of global CSP capacity, however, is still only about 1,200 MW.[15]

CSP utilizes thermal radiation from the sun. The thermal solar energy is typically transferred to a working fluid; the resultant heat is used to make steam. That steam is used in a steam turbine coupled to an electric generator. In some CSP applications, the thermal energy can be stored, spreading the output of the CSP facility over a longer period of time, resulting in capacity factors higher than those achieved with solar PV technology. CSP requires direct sunlight to function efficiently; cloud cover significantly degrades performance (in contrast to solar PV which does not exhibit as much performance degradation on cloudy days relative to CSP). As a result, most of the operating CSP plants are located in deserts in California, Spain, and the Middle East.

CSP has a relatively expensive capital cost. With the maturity of solar PV and the rapidly improving performance and steep forecasted capital cost price declines of battery energy storage systems (BESS), the technical and economic viability of CSP relative to a solar plus BESS applications may be relatively limited to areas with consistent solar thermal radiation.

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[14] http://cleantechnica.com/2015/09/22/now-solar-power-meet-evening-peak-load-hawaii/.

[15] http://www.energy.gov/articles/year-concentrating-solar-power-five-new-plants-power-america-clean-energy.

We currently have no CSP plants on our grids. Hawaiʻi Electric Light terminated the contract for the CSP-based Keahole Solar Power contract on September 9, 2014 after the facility failed to delivery energy for over 365 days and, after the project lost the land rights required for continued operations.

Hydrokinetic (Ocean) Energy

The several technologies of hydrokinetic energy capture the energy from flowing water that occurs in rivers and mostly in ocean currents. These technologies include tidal range, tidal stream, ocean current energy (including river in-stream energy), ocean wave energy, ocean thermal energy conversion (OTEC), and salinity gradient.

Three technologies—tidal range, tidal stream, and salinity gradient—have little potential for Hawaiʻi because of the methods employed to harness and generate energy. The other three technologies— ocean current energy (absent river in-stream energy), ocean wave energy, and ocean thermal energy conversion—all demonstrate future promise for generating energy in Hawaiʻi.

The world's first OTEC facility was developed in Hawaiʻi during the 1970s. An OTEC facility is currently generating 100 kW on Hawaiʻi Island with a 1 MW facility in the planning stages. Two small scale, pilot ocean wave projects have recently begun operating in Kaneohe Bay in Oʻahu; one generates 18 kW and the other generates 4 kW of electricity.

Both technologies are clearly still firmly in the development stage. Should this technology become commercially viable—offered by a vendor willing to financially back the development and performance of a full-scale plant—and demonstrate the ability to be financed without substantial subsidies, we will consider including OTEC as an option in future resource plans.

For more information, see "Hydrokinetic Energy" in Appendix H: Renewable Resource Options on Oʻahu for explanations of each technology and their commercial readiness.

GRID-SCALE RESOURCE ASSUMPTIONS

For the December 2016 PSIP update, the Companies have undertaken a more detailed analysis of the renewable resource potential on all of the islands, with particular emphasis on Oʻahu given its significantly higher energy needs and limited resource potential. If the renewable constraints on Oʻahu are significant, because of land use or community issues, the strategic need for off-island options becomes greater.

One constraint was the theoretical maximum potential for grid-scale PV and grid-scale wind on Oʻahu, Maui, and Hawaiʻi Island. NREL initially developed estimates that we employed in the April 2016 PSIP. For this December 2016 PSIP, we requested that NREL revise its analysis by relaxing these estimates using factors suggested by the Parties (mainly Dr. Matthias Fripp of the University of Hawaiʻi on behalf of the Ulupono Initiative). Dr. Fripp also conducted his own research to arrive at theoretical maximum potentials for grid-scale PV and grid-scale wind.

Table E-2 shows the differences in the results of the analyses by NREL, by Dr. Fripp, and a separate analysis performed by AWS Truepower[16] in 2014 regarding the grid-scale wind potential on Oʻahu.

Source	Oʻahu Grid-Scale Solar PV Potential		Oʻahu Grid-Scale Wind Potential	
	MW	*Description*	*MW*	*Description*
NREL	2,756	Sites outside excluded areas with annual capacity factors greater than 10%.	162	Sites outside excluded areas with mean wind speeds greater than 6.5 meters per second.
Ulupono (Dr. Fripp)	9,168	Fixed tilt PV; 20% land slope; 16%–26%. annual capacity factors.	2,680	12%–36% annual capacity factors.
	6,583	Fixed tilt PV; 10% land slope.		
AWS Truepower	n/a	n/a	189	Results of detailed study of available and developable wind sites by AWS Truepower for Castle & Cooke.

Table E-2. Comparison of Results of Oʻahu Resource Potential Analyses

For a more detailed discussion of this topic, see "Grid-Scale PV and Grid-Scale Wind Potential" in Appendix H: Renewable Resource Option on Oʻahu.

[16] AWS Truepower, *Potential Build-Out of Wind Energy Projects on Maui and Oʻahu – Site Screening and Preliminary Layout Development*, January 27, 2014; filed in Docket 2013-0169 on January 28, 2014.

Grid-Scale Resources by Island

Table E-3 summarizes the PSIP grid-scale resource options currently available for developing longer-term resource plans.

Resource Type	PSIP Assumed Project Block Sizes by Technology (MW)			
	O'ahu	*Maui*	*Moloka'i and Lana'i*	*Hawai'i Island*
Solar PV	1, 5, 10, 20	1, 5, 10, 20	1	1, 5, 10, 20
Onshore Wind	30	10, 20, 30	10 x 100 kW	10, 20, 30
Combustion Turbines	100	20.5	n/a*	20.5
Combined-Cycle	152 1x1	n/a	n/a	n/a
Internal Combustion Engines	27 (3 x 9 MW) 54 (6 x 9 MW) 100 (6 x 16.8 MW)	9	1	9
Geothermal	n/a	20†	n/a	20
Biomass	20	20	1	20
Waste-to-Energy	n/a	10	1	10
Offshore Wind	400	n/a	n/a	n/a
Off-Island Wind + Cable	200, 400	n/a	n/a	n/a

* A small CT was not considered for Moloka'i and Lana'i as their efficiencies are far less than those of an ICE unit of the same size.
† The geothermal option availability for Maui is limited to post 2030 in the December 2016 PSIP update analysis.

Table E-3. Preliminary New Grid-Scale Resource Options Available

Note: Properly evaluating the waste-to-energy facilities listed in Table E-3 depends, in large part, on acquiring reliable data regarding Hawai'i-specific cost and performance characteristics.

DISTRIBUTED ENERGY RESOURCES COST ASSUMPTIONS

We developed DER resource capital cost assumptions using the same sources and methodology as for grid-scale resources. We concentrated on DG-PV, residential lithium-ion BESS, and behind-the-meter commercial customer class BESS. We used IHS Energy's projections of distributed solar and energy storage costs, applied Hawai'i locational adjustments using RSMeans data, and added 4% for the Hawai'i General Excise Tax.

The available data for residential systems from IHS included only the storage medium—and not the balance-of-plant components (for example, inverters, enclosures, and switchgear) under the assumption that the distributed storage would be installed in conjunction with a solar PV system that incorporates the inverter and other balance-of-plant items. We believe that there are opportunities for stand-alone distributed energy storage under time-based pricing and demand response programs, so we added balance-of-plant cost estimates to develop stand-alone storage costs.

INTERISLAND TRANSMISSION ASSUMPTIONS

Our December 2016 updated PSIP analysis is based on interisland transmission cables using high voltage direct current (HVDC) technology, including converter stations on either end of a submarine cable. Without assurance that an interisland project has a high likelihood of development, potential vendors are unlikely to develop accurate costs for a specific interisland cable configuration.

So, rather than developing an accurate capital cost, we decided to first analyze the *benefits* of interisland transmission to determine if the sum total of such benefits could reasonably exceed this approximated cost. This break-even analysis assumes various "copper-plate" configurations: assume one or more cables transfers power between two or more points, without consideration of reliability; comparing the benefits against $600 million (the lowest known capital cost estimate); [17] and if benefits exceed cost, then conduct further analysis. E3 has analyzed the benefits of interisland transmission are part of developing this December 2016 PSIP.

Our goal is to determine, as quickly as possible, whether or not interisland transmission represents a viable resource option for Hawai'i that demands further research. We

[17] NextEra Energy developed and filed the $600 million estimate in Docket No. 2014-0169. (NextEra has since withdrawn from that proceeding.) This amount is at the low end of the $553–$969 million estimated range filed in our 2013 Integrated Resource Plan Report.

believe this two-step process—first evaluating the benefits, then, if warranted, evaluating the cost—is the most prudent, cost effective, and timely way to determine if interisland transmission demand further consideration as an option to pursue to help achieve our State's renewable energy goals.

For more information about interisland transmission, see "Interisland Transmission" in Appendix H: Renewable Resource Option on Oʻahu.

NEW RESOURCE RISKS AND UNCERTAINTIES

Developing grid-scale energy infrastructure, whether by a utility or an IPP, involves managing a number of implementation risks and uncertainties. Improperly managing these risks and uncertainties can adversely impact the State's ability to achieve its 100% RPS goal.

Technology Risks. Chosen technologies must be commercially proven, particularly if the project provides a significant portion of the grid's power. Commercially proven technologies are characterized by a well-capitalized and experienced vendor who can offer a performance warranty. Large projects also require an experienced and well-capitalized construction firm who stands behind contractual assurances that the project will be completed within budget, on time, and guarantee performance. The technology must be backed by a supply chain of parts and services necessary to operate the plant.

Solar PV, onshore wind, internal combustion engines, combustion turbines, combined-cycle units, geothermal, biomass technologies, and undersea cables generally meet these commercial requirements. Deep water offshore wind using floating platforms, OTEC, and ocean tidal and wave power are examples of technologies that have yet to meet these commercial requirements.

Permitting and Siting Risks. Depending on the project type and location, a typical project might involve consulting with dozens of state and federal agencies, preparing and disseminating notices, preparing numerous impact reports and studies, and navigating a maze of state and federal agency permitting processes. Many of the permits are subject to contested hearing processes; all permits are subject to appeals by those who oppose a particular project. This permitting complexity requires extremely well-qualified vendors with experience developing new infrastructure, and who understand the unique social and cultural dynamic of Hawaiʻi. Hawaiʻi's recent history with large infrastructure projects has been one characterized by community opposition and legal challenges.

In some cases, issued permits have been revoked because of procedural errors, after developers have spent significant time, effort, and money working in good faith with the communities and agencies to obtain those permits.[18] This atmosphere of uncertainty leads to less competition for new projects from highly qualified vendors (with resulting higher costs for the projects and greater risk on non-completion) and a higher cost of capital. This is a significant risk for achieving Hawai'i's 100% RPS goals. Achieving 100% RPS requires significant new infrastructure, significant amounts of capital to be raised in capital markets, and highly qualified developers with experience in completing complex projects on time and within budget.

Construction Risks. Construction risks are typically managed by the project developer, but such risks can be significant. Unforeseen site conditions, discovery of endangered species and or previously unknown archeological finds, labor strikes and lockouts, and material and labor shortages all can affect the cost and schedule of construction. Extended delays in construction can result in cost uncertainty as commodity prices and interest rates fluctuate. These risks are manageable, but again, large infrastructure construction risks require sophisticated construction project management skills and experience.

Financing Risks. Large infrastructure projects require significant amounts of capital. The incremental capital to develop these projects must be raised in capital markets. Most projects combine equity with debt. The willingness of both debt and equity providers to supply the capital to build new infrastructure projects, and the price of the capital (that is, equity returns required and debt interest rates) depends on a number of factors. First, capital providers assess the merits of the project itself. Second, they assess the regulatory and political risks associated with the project, the relative certainty (or uncertainty) of the regulatory and political environment, and whether that environment is conducive to a return of, and a return on, capital. Third, in the case of major energy infrastructure, they assess the financial strength of the local utility. Finally, they assess the ability of the project developer to manage the extensive risks outlined herein.

When substantial risks are present in the project's environment, fewer capital providers will be available to compete for providing this capital. As a result, the cost of capital borne by customers will be higher.

[18] "Hawai'i Supreme Court Revokes Construction Permit For Thirty Meter Telescope On Mauna Kea." *Forbes*. December 3, 2015. http://www.forbes.com/sites/alexknapp/2015/12/03/hawaii-supreme-court-revokes-construction-permit-for-thirty-meter-telescope-on-mauna-kea/#550cc2223094.

F. NREL Reports

The Companies retained the National Renewable Energy Laboratory (NREL) to prepare and submit four study reports to support our *PSIP Update Report: December 2016*. These reports assessed resource potentials, wind and solar power profiles, and resource costs on three of the islands we serve: O‘ahu, Maui, and Hawai‘i Island. The Companies used the data from these reports in our modeling analysis to develop the December 2016 updated PSIP.

These studies are:

- *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource* (page F-2) assessed these three resource potentials. Since these utility-scale resources are owner agnostic, they are better characterized by the term "grid-scale". Based on Party input, we requested NREL to update the O‘ahu grid-scale PV potential of this study to include 100% of agricultural B and C class land with slopes less than or equal to 10%.
- *Aggregated Wind Power Profile Time Series* (page F-37) used two scenarios to calculate hourly onshore wind power profiles.
- *Aggregated Solar Power Profile Time Series* (page F-43) used solar radiation data from 1998 through 2014 to calculate solar power profiles.
- *Electricity Generation Capital, Fixed, and Variable O&M Costs* (page F-61) independently assessed our resource data assumptions.

Each report with an attendant summary is presented here.

UTILITY-SCALE ONSHORE WIND, UTILITY-SCALE PV, AND CSP POTENTIAL RESOURCE

This NREL report describes their studies that estimated the onshore grid-scale wind and grid-scale PV potential for each of the three main islands we serve: O‘ahu, Maui, and Hawai‘i Island. The report estimated the maximum grid-scale wind potential for each of the three islands to be as follows:

Island	Potential MWac
O‘ahu	183
Maui	840
Hawai‘i	3,532

Table F-1. Maximum Grid-Scale Wind Potential for O‘ahu, Maui, and Hawai‘i Island

The report estimated the maximum grid-scale PV potential for each of the three islands to be as follows:

Island	Potential MWac (<3% slope)	Potential MWac (<5% slope)	Potential MWac (<10% slope; Ag A)	Potential MWac (<10% slope; Ag A,B,C)
O‘ahu	583	796	1,434	2,970
Maui	272	783	n/a	n/a
Hawai‘i	11,514	30,484	n/a	n/a

Table F-2. Maximum Grid-Scale PV Potential for O‘ahu, Maui, and Hawai‘i Island

The initial study (included in our *PSIP Update Report: April 2016*) excluded lands with a greater than 3% and 5% slope, urban areas, wetlands, park lands, mountainous areas, ravines, and certain agricultural areas (100% of A class lands are excluded and 90% of B and C class lands are excluded[1]) for grid-scale PV development. The study thus, assumed that the remaining land was available to be developed for grid-scale PV. The capacity-weighted average land use for PV was assumed to be 8.7 acres per MWac. Wind excluded lands with slopes greater than 20%, minimum threshold wind speed of 6.5 meters per second, and assumed power density of 3 MW per kilometer.

At our request, NREL reanalyzed the PV potential for O‘ahu based on Party input. The updated PV resource potential analysis for O‘ahu increased the slope exclusion criteria to 10%, and included all agricultural B and C land.

[1] Please refer to Appendix A: Glossary and Acronyms for an explanation of agricultural land classifications and how they are developed.

NREL has also directly reviewed assumptions of resource potentials for O‘ahu provided by Dr. Mathias Fripp on behalf of Ulupono Initiative. NREL states that the differences in resource potential are driven by differences in land use assumptions. NREL states that a better estimate of resource potential could be obtained from a site by site analysis.

The maximum potential for grid-scale wind suggested by this NREL report (183 MW) aligns with the results found by AWS Truepower in 2012,[2].which was a site by site analysis of the wind potential on O‘ahu. That report concluded the maximum potential wind generation to be 189 MW, but because of a number of exogenous factors, concluded the remaining actual potential to be about 40–50 MW.[3]

Maui and Hawai‘i Island has more than adequate renewable resource potential (for both grid-scale PV and grid-scale wind) to meet their native electrical loads and, as a result, can be met by on-island resources.

[2] Docket 2013-0169; *Potential Build-Out of Wind Energy projects on Maui and O‘ahu, Site Screening and Preliminary Layout Development*, prepared by AWS Truepower for Castle & Cooke, dated January 27, 2014; filed as a public comment on January 28, 2014.

[3] Docket 2013-0169, *Public Comments of Castle & Cooke*, January 28, 2014: pp 17–18.

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

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Erol Chartan
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Anthony Lopez
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Bri-Mathias Hodge

This report was prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on December 9, 2016.

This report by the National Renewable Energy Laboratory NREL presents estimates for the total amount of developable utility-scale wind, utility-scale solar photovoltaic (PV) and concentrated solar power (CSP) potential for the Hawaiian islands of Oʻahu, Maui, and Hawaiʻi Island. These estimates of technical potential do not take into account existing or committed wind and solar plants. Existing solar and wind resource data and the use of standard exclusion factors were utilized by NREL to provide independent estimates. Sites where both solar PV and wind could be deployed were examined together as possible dual use sites.

Table F-3 through Table F-8 show the utility-scale onshore wind and utility-scale solar PV resource potentials (in MWac terms) for Hawaiʻi Island, Maui, and Oʻahu for the following four analyses that differ in terms of land exclusions:

1. Default slope analysis
2. Default slope analysis without DOD exclusions
3. Improved slope analysis without DOD exclusions
4. Improved slope analysis without DOD exclusions with updated agricultural land exclusions.

Table F-3 to Table F-5 show the wind potential with an additional exclusion for each row excluding any site whose mean wind speed at 80m height is lower than the figures stated. Table F-6 to Table F-8 show the utility-scale PV potential organized by two main exclusions: capacity factor and slope. The slope exclusions exclude all land with a slope steeper than the figure stated as potential for PV and the capacity factor exclusions exclude all PV whose capacity factor is lower than the figures stated. The difference between the default and improved slope analyses and the updated agricultural land exclusions are described in sections 4.1 and 4.2.

No technical potential values are provided for CSP. When considering the direct normal irradiance potential and the GIS exclusion factors in the three islands, very limited CSP potential exists.

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	3,276	3,276	3,303	3,532
>= 7.5	2,107	2,107	2,123	2,236
>= 8.5	1,290	1,290	1,299	1,334

Table F-3. Grid-Scale Onshore Wind Potential for Hawai'i (MWac)

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	698	698	700	840
>= 7.5	412	412	417	448
>= 8.5	117	117	121	118

Table F-4. Grid-Scale Onshore Wind Potential for Maui (MWac)

Mean Wind Speed (m/s) at 80m	Analysis 1 (MW)	Analysis 2 (MW)	Analysis 3 (MW)	Analysis 4 (MW)
>= 6.5	174	183	154	162
>= 7.5	81	81	69	68
>= 8.5	19	19	16	16

Table F-5. Grid-Scale Onshore Wind Potential for O'ahu (MWac)

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 3%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	10,868	30,634	10,868	30,703	12,557	33,012	11,514	30,484
>= 12	10,833	30,573	10,833	30,643	12,523	32,949	11,481	30,421
>= 14	10,703	30,036	10,703	30,105	12,385	32,405	11,467	30,039
>= 16	8,339	20,204	8,339	20,273	9,448	21,873	8,646	20,312
>= 18	5,481	14,841	5,481	14,911	6,322	16,338	6,019	15,757
>= 20	2,469	8,315	2,469	8,385	3,075	9,193	3,075	9,189

Table F-6. Grid-Scale Solar PV Potential for Hawai‘i (MWac)

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)	
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%
>= 10	0	1,321	0	1,321	697	1,443	272	783
>= 12	0	1,321	0	1,321	697	1,443	272	783
>= 14	0	1,321	0	1,321	697	1,443	272	783
>= 16	0	1,321	0	1,321	697	1,443	272	783
>= 18	0	1,321	0	1,321	697	1,443	272	783
>= 20	0	1,110	0	1,110	697	1,230	272	576

Table F-7. Grid-Scale Solar PV Potential for Maui (MWac)

Capacity Factor (%)	Analysis 1 (MW)		Analysis 2 (MW)		Analysis 3 (MW)		Analysis 4 (MW)			
	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 3%	Slope 5%	Slope 10%	Slope 10%*
>= 10	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 12	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 14	0	1,338	67	2,155	1,527	2,301	583	796	1,434	2,970
>= 16	0	1,338	67	2,155	1,527	2,301	583	796	1,428	2,923
>= 18	0	1,338	67	2,134	1,527	2,277	583	793	1,368	2,756
>= 20	0	414	67	895	692	968	329	397	664	1,053

*"B" and "C" agricultural lands are not excluded (see section 4.2 for details).

Table F-8. Grid-Scale Solar PV Potential for O‘ahu (MWac)

II. Report Structure

This report is split into four main sections: introduction, overview of data and modeling assumptions, GIS exclusions, and the resource potential maps (for Analysis 1) for each technology type: utility-scale onshore wind, utility-scale PV, and concentrated solar power.

III. Overview of Data & Modeling Assumptions

a. Utility-Scale Onshore Wind

The REEDS data set containing utility-scale wind speed data was supplied from AWS [1]. A typical meteorological year (TMY) method was used with 20 km summary resolution where simulated hourly wind resource data and statistics were generated for each 3% gross capacity factor interval calculated from the 200 m spatial map. The mean wind speed data at 200 m spatial resolution were attained for 80 m height. The power density assumed was 3 MW/km. as used in the Wind Vision report and seen in the Wind Vision Appendices [2].

b. Utility-Scale PV

Mean solar radiation data over the years 1998 to 2014 was taken from the latest National Solar Radiation Database (NSRDB) [3–5] which has 4 km x 4 km and 30 minute resolution. NSRDB is a serially complete collection of meteorological and solar irradiance data sets. The database is managed and updated using the latest methods of research by a specialized team of forecasters at the National Renewable Energy Laboratory (NREL). The data spans 1998–2014 and the latest version now uses satellite retrievals. Cloud properties, aerosol depth, and precipitable water vapor are used to calculate Global Horizontal Irradiance (GHI) values at each point in the mesh.

The System Advisor Model (SAM) [6] with parameters DC–AC ratio = 1.5 was used to attain capacity factors for 1-axis tracking panels with tilt fixed at zero. Please refer to Appendix A for an extended list of the SAM parameters used in this analysis. SAM is a performance and financial model which makes performance predictions for grid-connected power projects based on parameters that you specify as inputs to the model. It is distributed for free by NREL. SAM's user interface allows the user to input variables and simulation controls and displays tables and graphs of results. Information on the code can be found in the PVWatts Version 5 Manual [7].

The capacity-weighted average land use for a 1-axis small PV plant was taken to be 8.7 acres/MWac [8].

Figure F-1 illustrates the inter-annual variability of capacity factors as a function of location index. It highlights the value of having a wide temporal range of data. In this plot the two-dimensional geospatial dataset is displayed as a sequence rather than a map and each point in the sequence corresponds to a latitude and longitude in a geospatial grid. Neighbors in the sequence are either neighbors in latitude or longitude depending on how the data is converted from the geospatial grid, that is, whether the data is traversed in the latitude or longitude dimension.

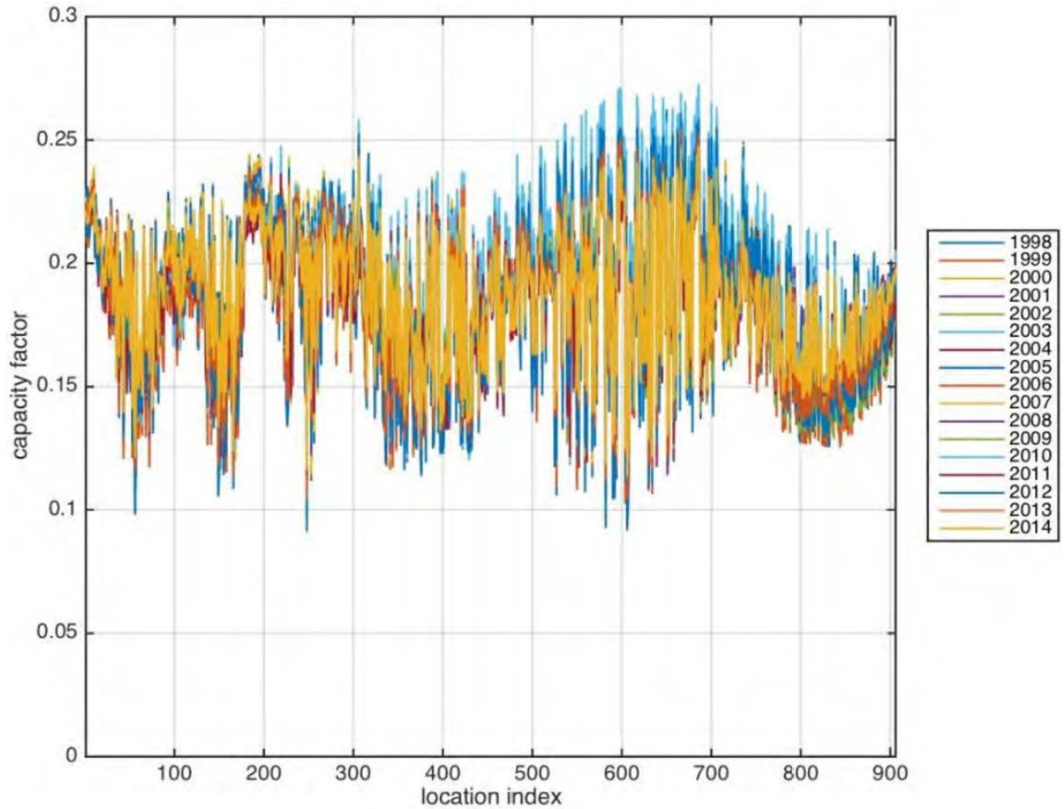


Figure F-1. Annual Variability of Solar Capacity Factors

c. Concentrated Solar Power (CSP)

In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB. In order to assess the CSP potential for the three islands, a Direct Normal Irradiance (DNI) map has been created using mean values from the NSRDB as per the description above. DNI > 400 W/m^2 was calculated by finding the number of half hour intervals in a year where DNI > 400 W/m^2, dividing by the number of half hour intervals in the year and averaging across 1998–2014. The value 400 is chosen as a suitable benchmark given the current CSP technology.

Figure F-2 shows the percentage of half hour intervals for all the years to give some visual indication of the variability in this statistic.

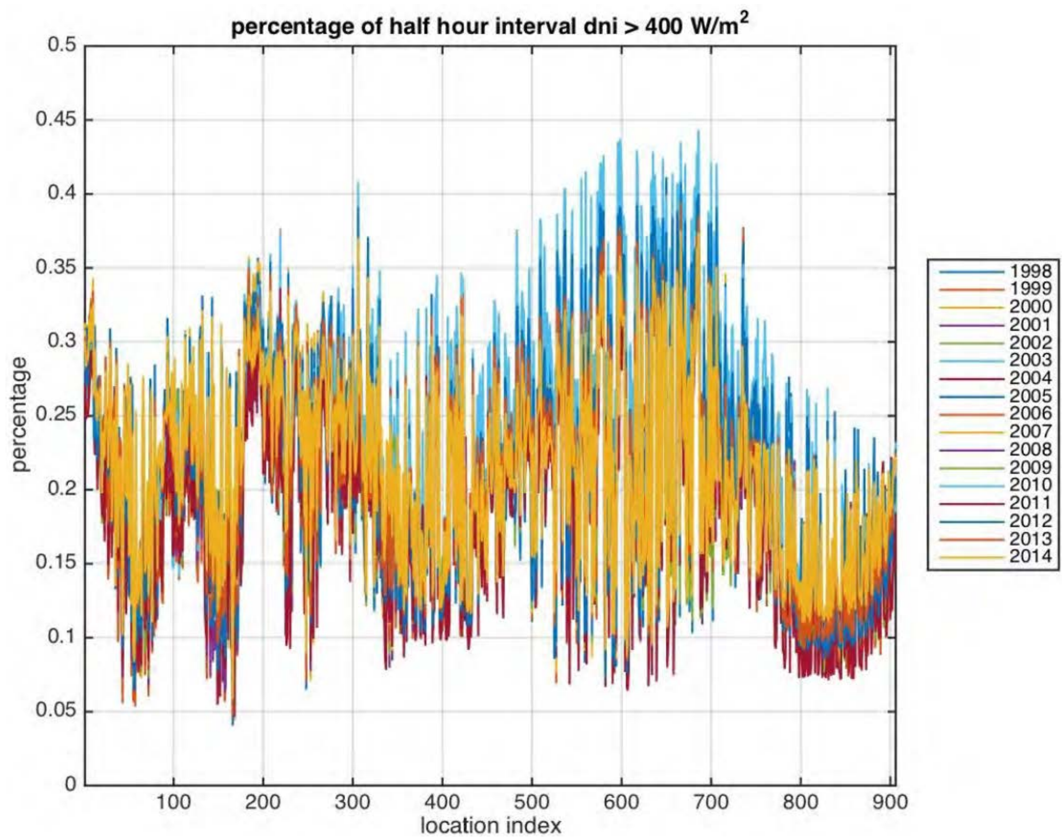


Figure F-2. Percentage of Half-Hour Interval DNI > 400 W/m^2

IV. GIS Exclusions

Geospatial analysis and mapping of the wind and solar resources was accomplished through the use of Geographic Information Systems (GIS) technology. Using relevant and available geographic data, areas likely to be impediments to development were excluded from consideration. Standard exclusions applied to all technologies were National and State Parks, US Fish & Wildlife Service (FWS) lands, areas zoned as urban, areas classified as Important Agricultural Land, areas within any "A" level flood zone, areas classified as lava flow hazard zones 1 and 2, all military or Department of Defense (DOD) lands, and wetlands. All of these datasets, except for National and State Parks and FWS lands were acquired from the state through the Hawai'i Office of Planning website (planning.hawaii.gov). Additional resource-specific exclusions were applied as well. The photovoltaic analysis included exclusions for terrain slopes greater than either 3% or 5%, as well as a minimum contiguous area requirement of 1 km2. Concentrating solar included a slope exclusion of greater than 3% as well as the minimum contiguous area requirement of 1 square kilometer, plus a minimum resource threshold of 5/kWh/m2/day irradiance. Wind included an exclusion of slopes greater than 20% [9] and a minimum wind speed resource threshold of 6.5 m/s, 7.5 m/s, or 8.5 m/s.

4.1 Improved Slope Analysis

A percent slope analysis was performed in the default analysis in order to create slope constraints of 3% and 5% for PV and 20% for wind. The elevation data used for this analysis was 1/3 arc-second (approx. 10 meter) digital elevation models (DEMs) from the National Elevation Dataset (NED) available through the US Geological Survey's nationalmap.gov. These DEMs are currently the best available, but do contain known artifacts and artificial anomalies due to data sources, processing methods, etc. One of these anomalies is terracing effect, and can be thought of as appearing like artificial terraces in the data. Figure F-3 shows a typical agricultural parcel on the island of O'ahu.

Figure F-3. Typical Agricultural Parcel on O'ahu

Figure F-4 shows the same area after the results of a 3% slope analysis has been applied. Areas highlighted in yellow are where slope is not more than 3%. All other areas are greater than 3%.

Figure F-4. Typical Agricultural Parcel on O'ahu after 3% Slope Analysis

It is evident from aerial photographs that the terracing effect seen in Figure F-4 is not a genuine geographic feature, but a result of artifacts in the data. This terracing caused a large number of parcels to be divided incorrectly into strips of land rather than being shown as contiguous areas. This posed no significant problem for the wind analysis, which did not have a minimum contiguous area requirement, but it significantly reduced potential land area for PV, which for the purposes of this study included a minimum contiguous area requirement of 1 km^2. Upon applying that constraint, much potential land such as those areas shown in Figure F-2 were eliminated.

In order to compensate for the artifacts in the data and attempt to recover the artificially segmented areas, the Boundary Clean tool was applied using ArcGIS. Boundary Clean is a process by which zones in a raster are expanded and shrunk programmatically over large areas in an attempt to fill in narrow bands or tiny gaps of missing data as well as eliminate tiny stray islands such as those that run along ridges seen in Figure F-4.

The expansion/shrinking was run twice, and the results are shown in Figure F-5. Large areas of land were unified, and tiny scattered areas were largely eliminated.

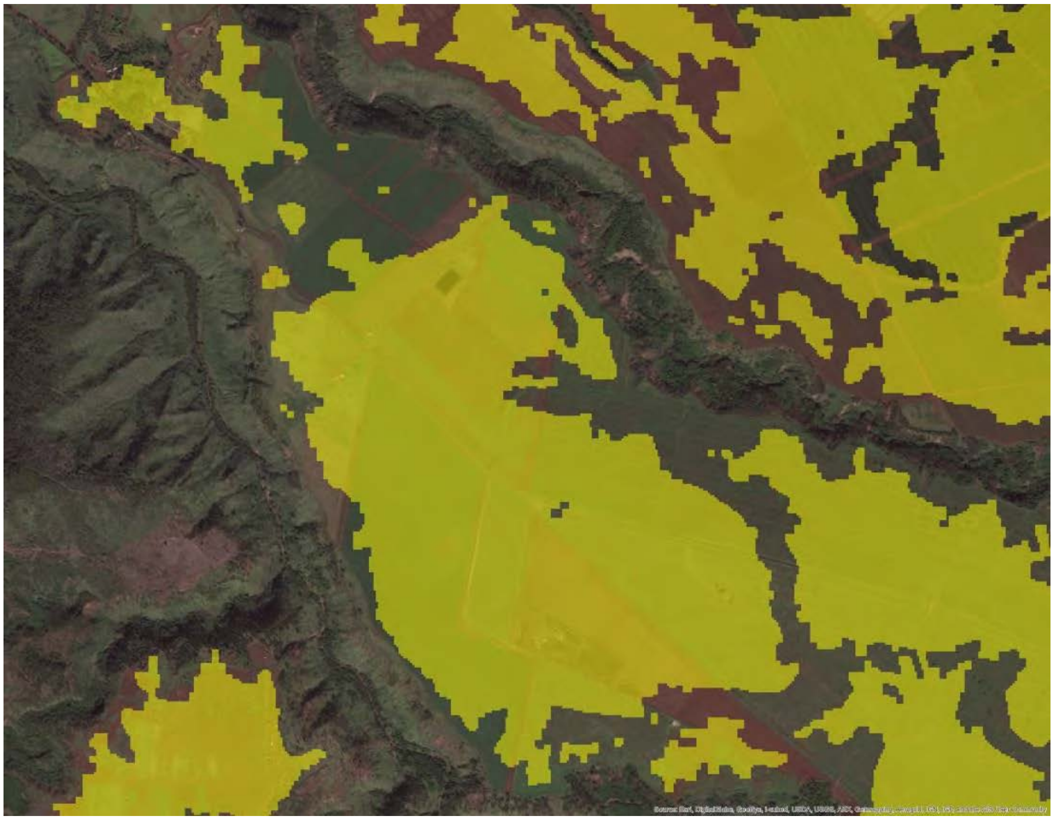


Figure F-5. Typical Agricultural Parcel on O'ahu after the Boundary Clean Tool Analysis

This process was repeated on the 5% and 20% slope analyses, and the resulting "clean" slope areas were used to run the final technical potential analysis.

After applying the minimum contiguous area constraint, available land area for PV development increased significantly. Small land areas were still dropped out, but the larger, now-intact areas remained. For the wind analysis, however, the impact was minimal, and in some cases the clean slope decreased available land area. As previously stated, cleaning the slope analysis filled in gaps, but it also eliminated numerous scattered, tiny, disconnected areas. As the wind analysis did not consider a minimum contiguous area, these tiny areas in the slope data that was not cleaned were left in the original analysis. The net result for wind was the loss of small scattered areas but the gain of areas within filled gaps. By chance, some islands had a net gain and others had a net loss, but in all cases the differences were relatively minor.

Post-processing the calculated slope data by cleaning the boundaries appears to have yielded a more realistic representation of the slope of the terrain, and thus a more realistic estimate of the resource potential in the state. As with any analysis, a site-specific analysis combined with proper ground-truthing should be implemented to verify site suitability, as the methods employed here are suitable only for a broad sweep of the state to understand general scale and distribution of development potential.

4.2 Updated Agricultural Land Exclusions

For Analyses 1, 2, and 3, agricultural land exclusions include lands classified as "Important Agricultural Land" (IAL) in the Hawai‘i Office of Planning website (planning.hawaii.gov) for both utility-scale onshore wind and utility-scale solar PV.

For Analysis 4, no agricultural land exclusions are considered for utility-scale onshore wind. For utility-scale solar PV, a different agricultural land classification from the Hawai‘i Office of Planning is used in addition to the IAL exclusions. This alternative agricultural land classification divides agricultural lands in five zoning designations: A, B, C, D, and E. Taking into consideration the statute* that details the agricultural land zoning designations, the following exclusions (in addition to IAL exclusions) are applied to the utility-scale solar PV resource assessment for Analysis 4:

- 100% of "A" lands are excluded
- 90% of "B" and "C" lands are excluded

It is important to note that a utility-scale PV resource area was removed if it was made too small to meet the minimum contiguous area requirement (1 km^2) due to an intersection with an "A" land. However, resource areas that fell partially or fully within "B" or "C" lands were not removed based on the minimum continuous area requirement; the total resource area within the "B" or "C" agricultural zone was reduced by 90%.

In summary, Analysis 4 includes the following agricultural land exclusions:

- Utility-scale onshore wind:
    - No agricultural land exclusion is applied

- Utility-scale solar PV:
    - "IAL" lands excluded
    - 100% of "A" agricultural lands excluded
    - 90% of "B" and "C" agricultural lands excluded

* http://www.capitol.hawaii.gov/hrscurrent/vol04_Ch0201-0257/HRS0205/HRS_0205-0002.htm

V. Resource Potential Maps

The following self-explanatory maps refer to Analysis 1 and are included herein after in the following order:

Utility-Scale Onshore Wind

Figure F-6. Grid-Scale Onshore Wind Development Potential for All Hawaiian Islands
Figure F-7. Grid-Scale Onshore Wind Development Potential for Hawai‘i Island
Figure F-8. Grid-Scale Onshore Wind Development Potential for Maui
Figure F-9. Grid-Scale Onshore Wind Development Potential for Maui with Clusters
Figure F-10. Grid-Scale Onshore Wind Development Potential for O‘ahu

Utility-Scale PV

Figure F-11. Capacity Factor for All Hawaiian Islands
Figure F-12. Grid-Scale PV Development Potential for All Hawaiian Islands (3% slope exclusion)
Figure F-13. Grid-Scale PV Development Potential for Hawai‘i Island (3% slope exclusion)
Figure F-14. Grid-Scale PV Development Potential for Maui (3% slope exclusion)
Figure F-15. Grid-Scale PV Development Potential for O‘ahu (3% slope exclusion)
Figure F-16. Grid-Scale PV Development Potential for All Hawaiian Islands (5% slope exclusion)
Figure F-17. Grid-Scale PV Development Potential for Hawai‘i Island (5% slope exclusion)
Figure F-18. Grid-Scale PV Development Potential for Maui (5% slope exclusion)
Figure F-19. Grid-Scale PV Development Potential for O‘ahu (5% slope exclusion)
Figure F-20. Grid-Scale PV Development Potential for O‘ahu (10% slope exclusion; Ag B and C class land 90% excluded)
Figure F-21. Grid-Scale PV Development Potential for O‘ahu (10% slope exclusion; Ag B and C class land highlighted)
Figure F-22. Grid-Scale PV Development Potential for O‘ahu (10% slope exclusion; Ag B and C class land included)

Concentrated Solar Power

Figure F-23. Direct Normal Irradiance for All Hawaiian Islands
Figure F-24. Concentrated Solar Power Development Potential for All Hawaiian Islands
Figure F-25. Concentrated Solar Power Development Potential for Hawai‘i Island

[*] "B" and "C" agricultural lands are highlighted in the map.
[†] "B" and "C" agricultural lands are not excluded (see section 4.2 for details).

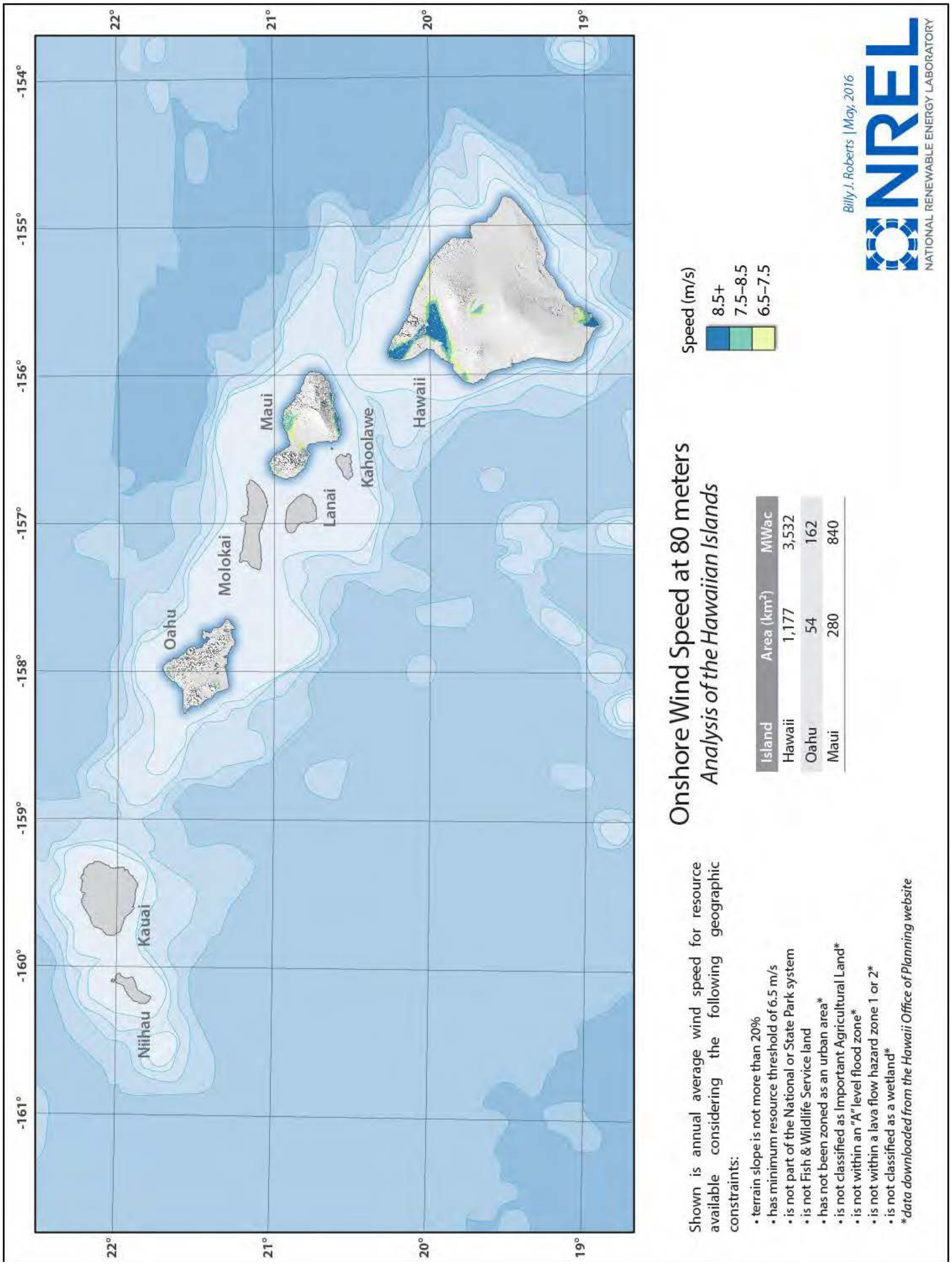


Figure F-6. Grid-Scale Onshore Wind Development Potential for All Hawaiian Islands

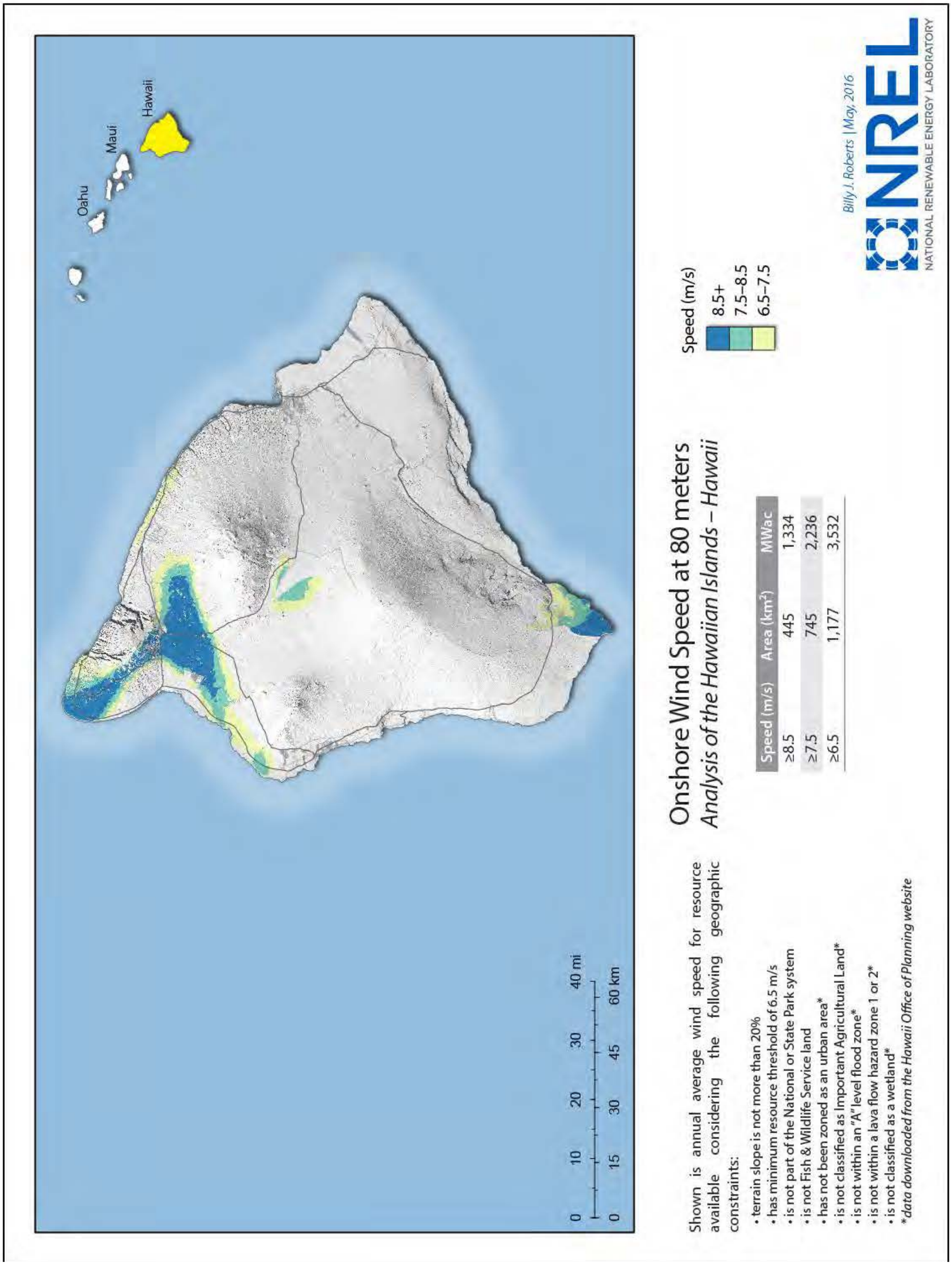


Figure F-7. Grid-Scale Onshore Wind Development Potential for Hawai'i Island

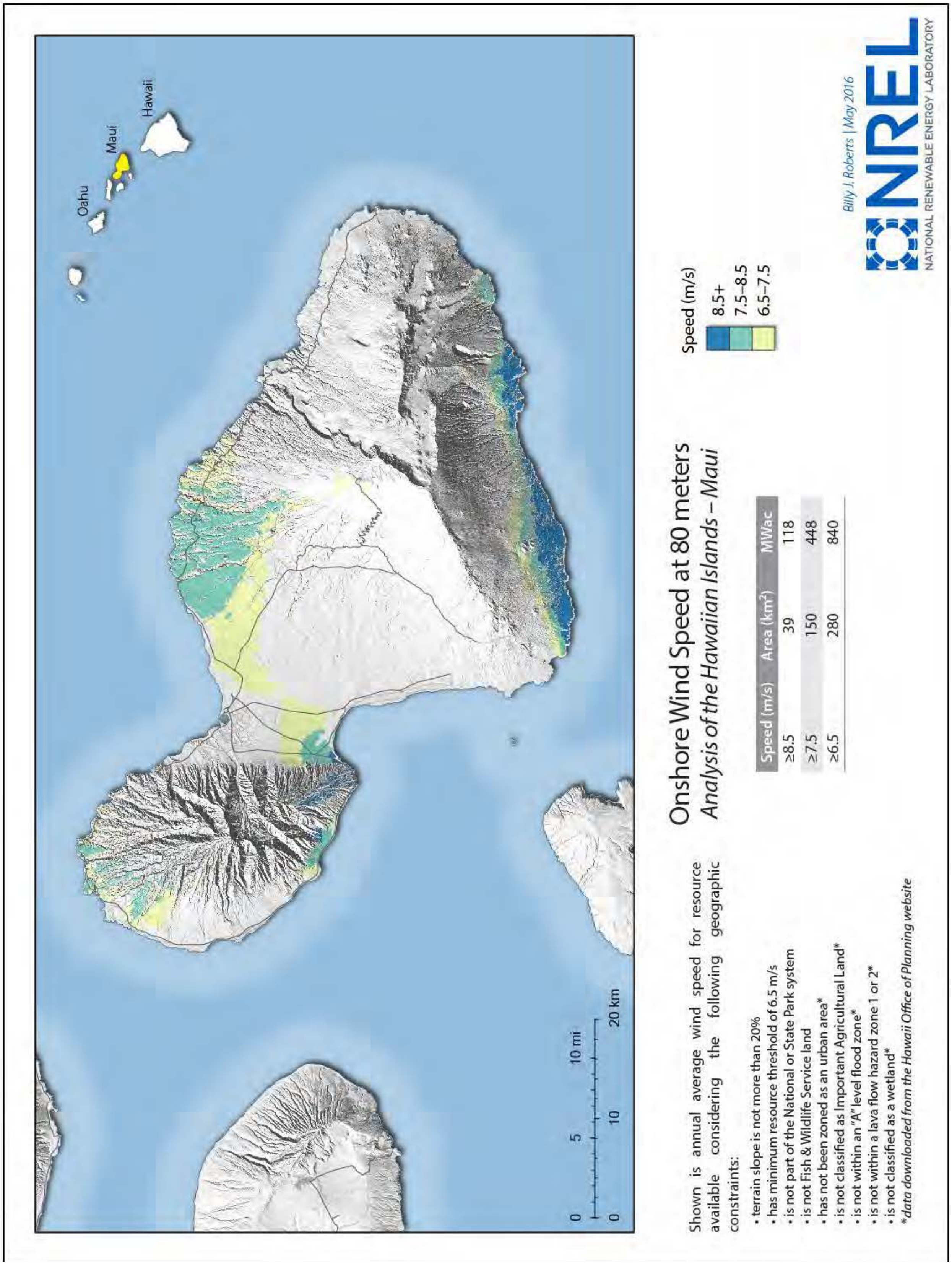


Figure F-8. Grid-Scale Onshore Wind Development Potential for Maui

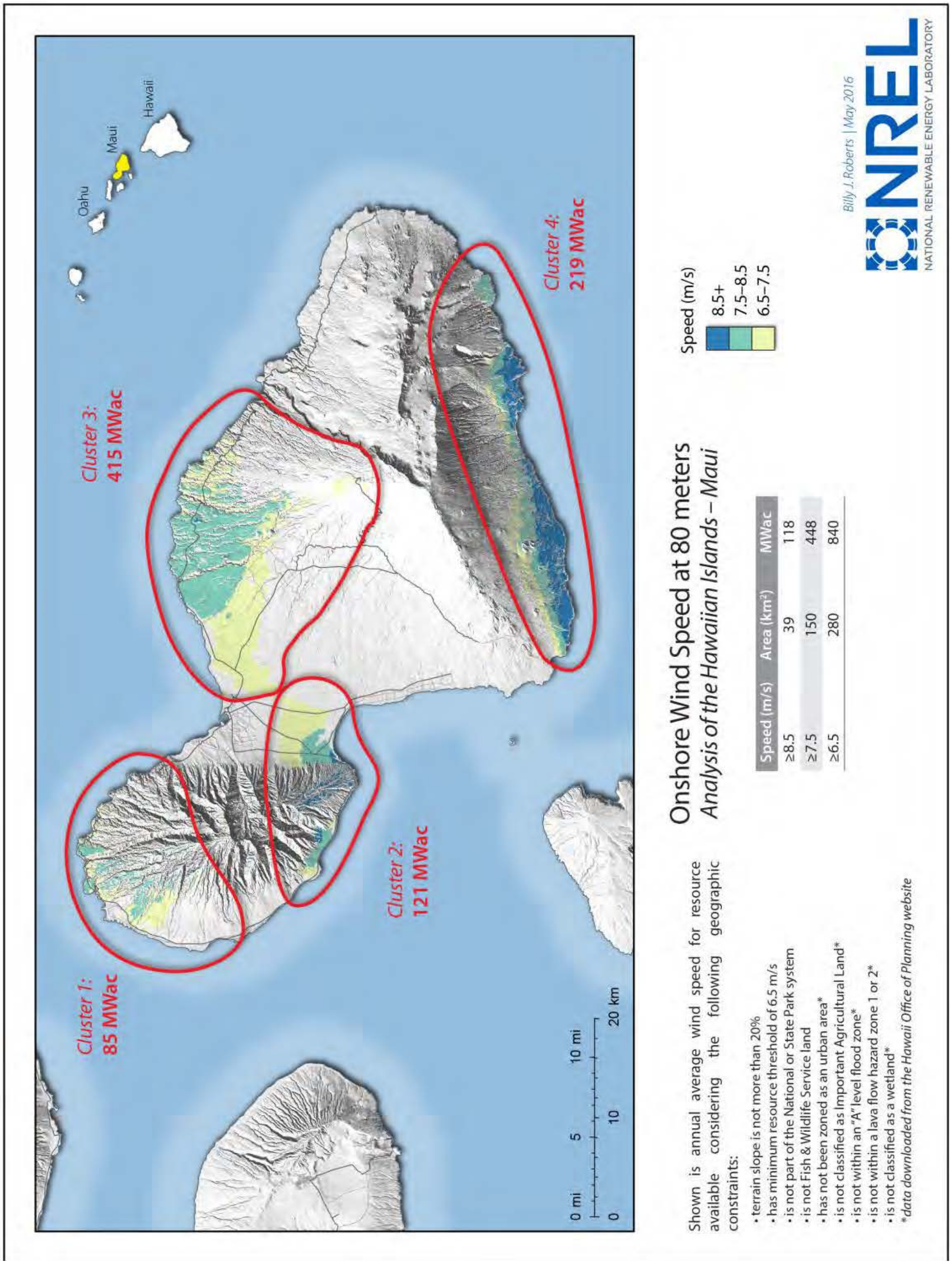


Figure F-9. Grid-Scale Onshore Wind Development Potential for Maui with Clusters

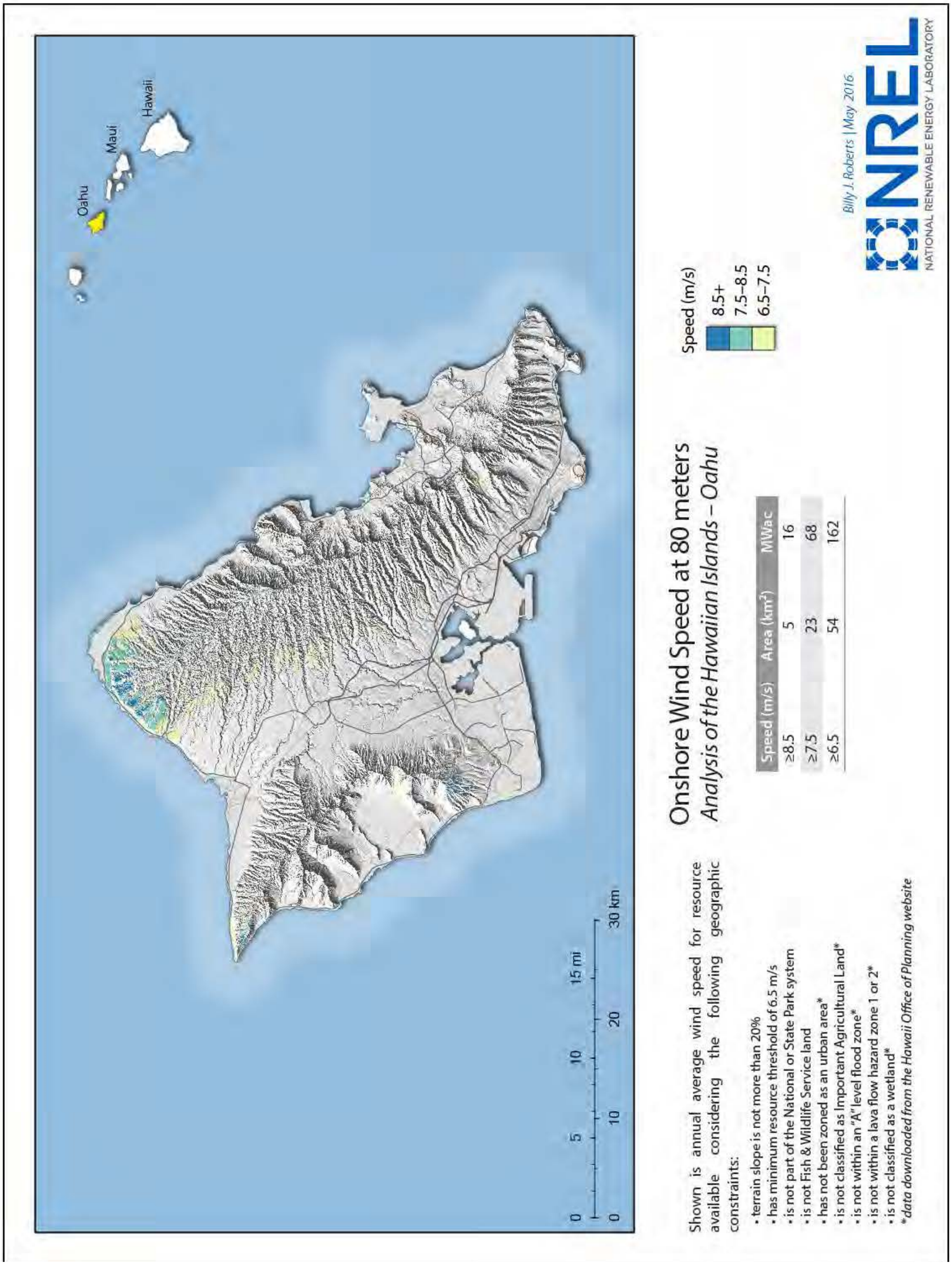


Figure F-10. Grid-Scale Onshore Wind Development Potential for O'ahu

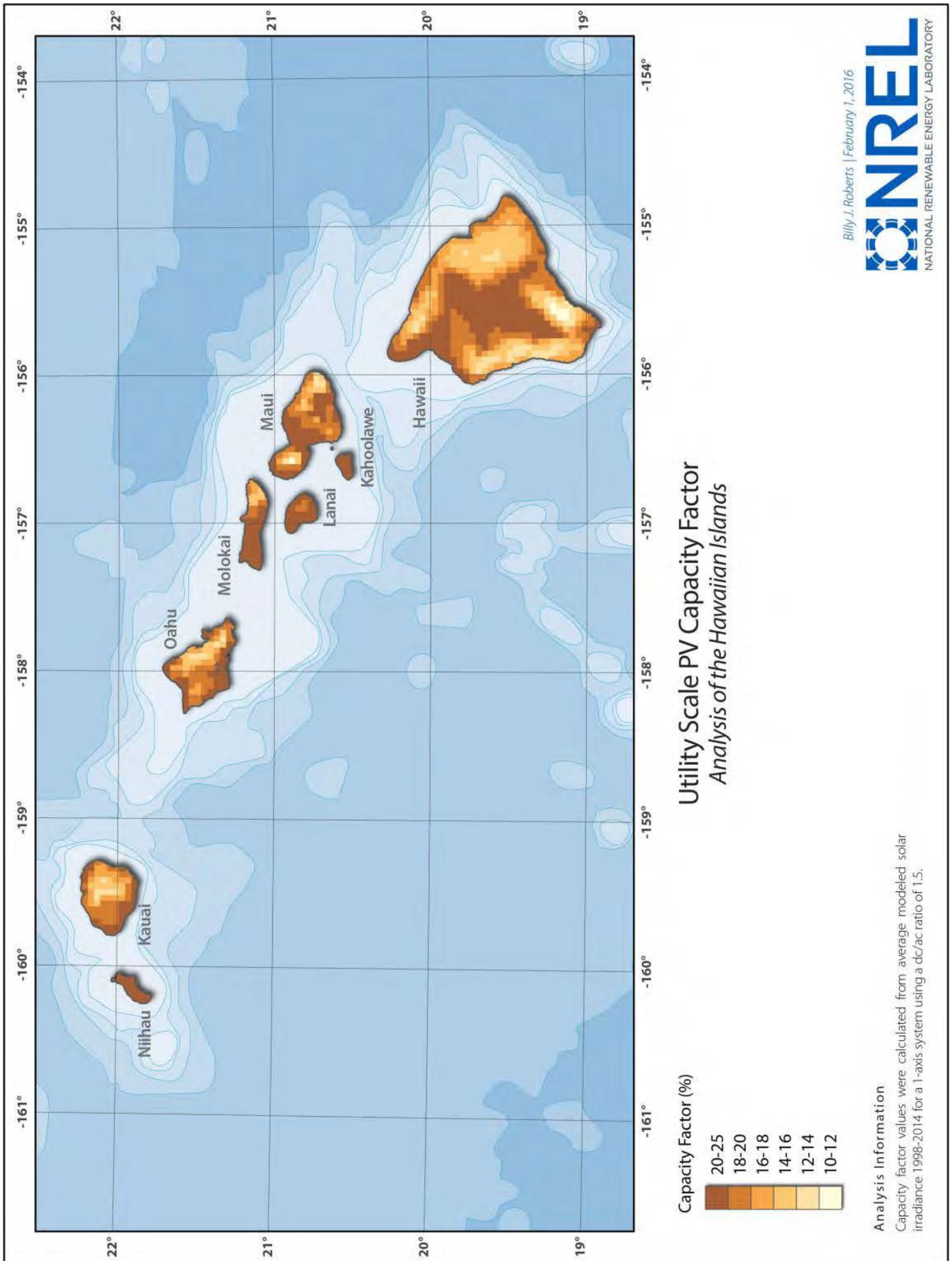


Figure F-11. Capacity Factor for All Hawaiian Islands

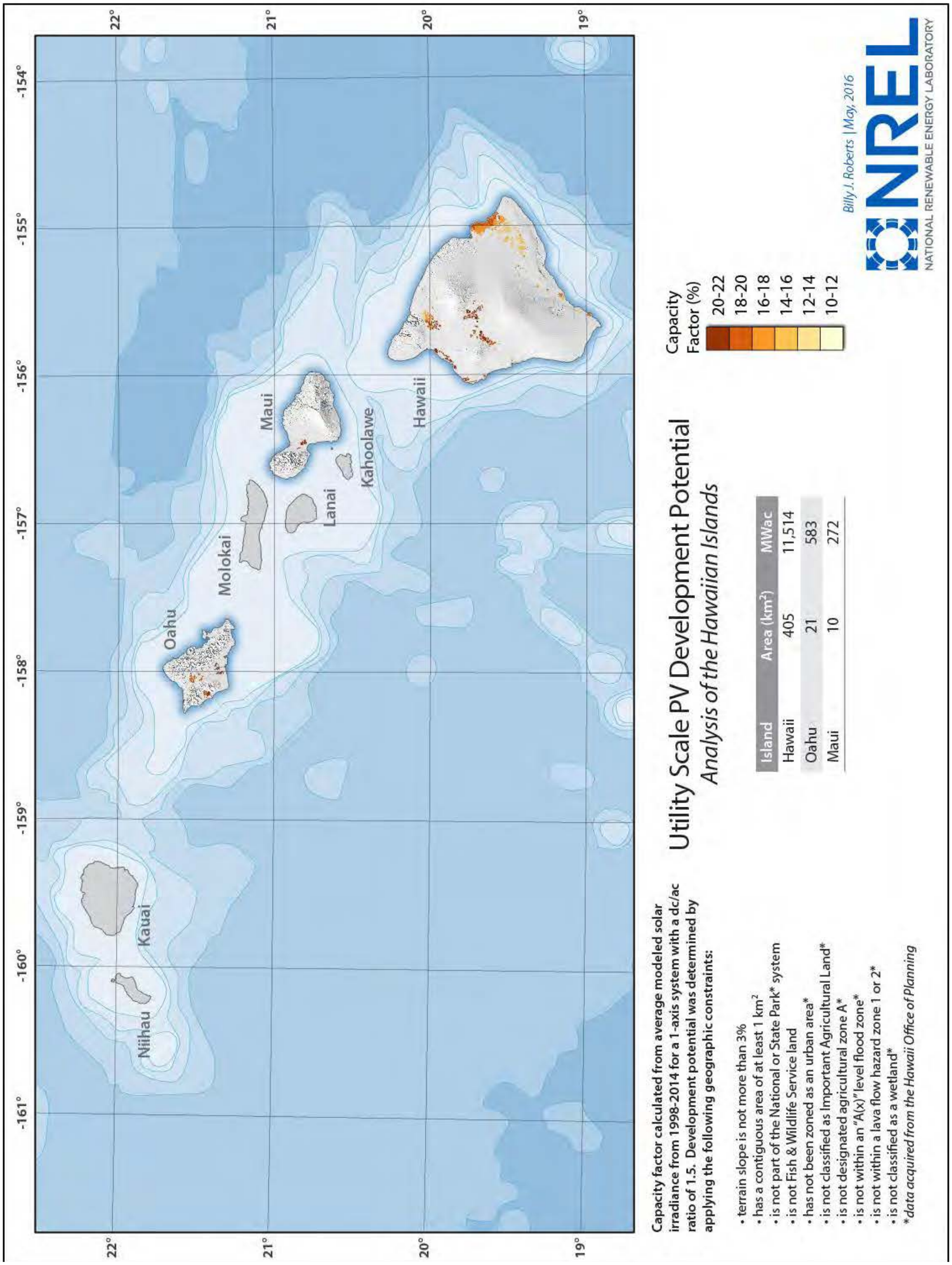


Figure F-12. Grid-Scale PV Development Potential for All Hawaiian Islands (3% slope exclusion)

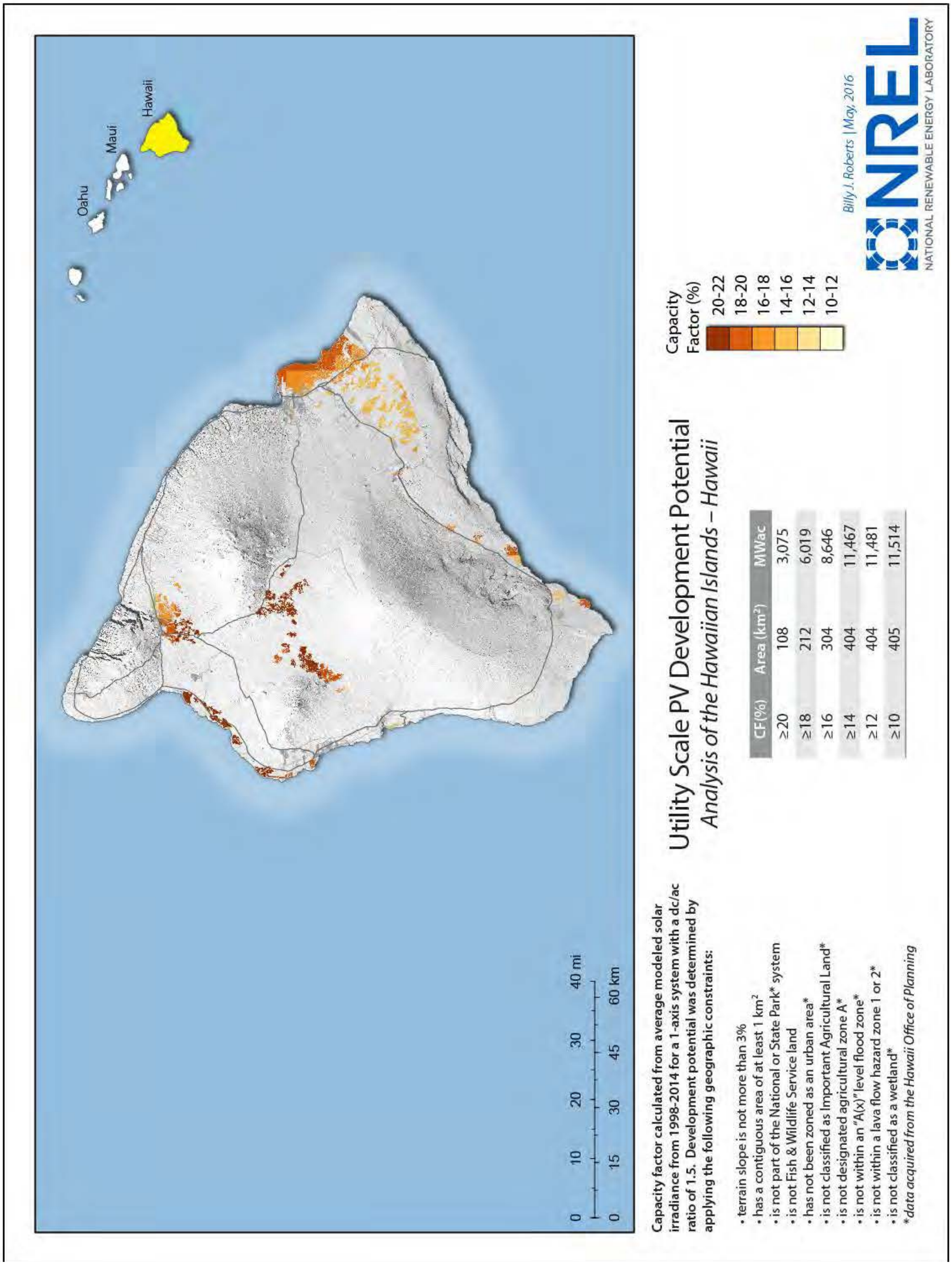


Figure F-13. Grid-Scale PV Development Potential for Hawai'i Island (3% slope exclusion)

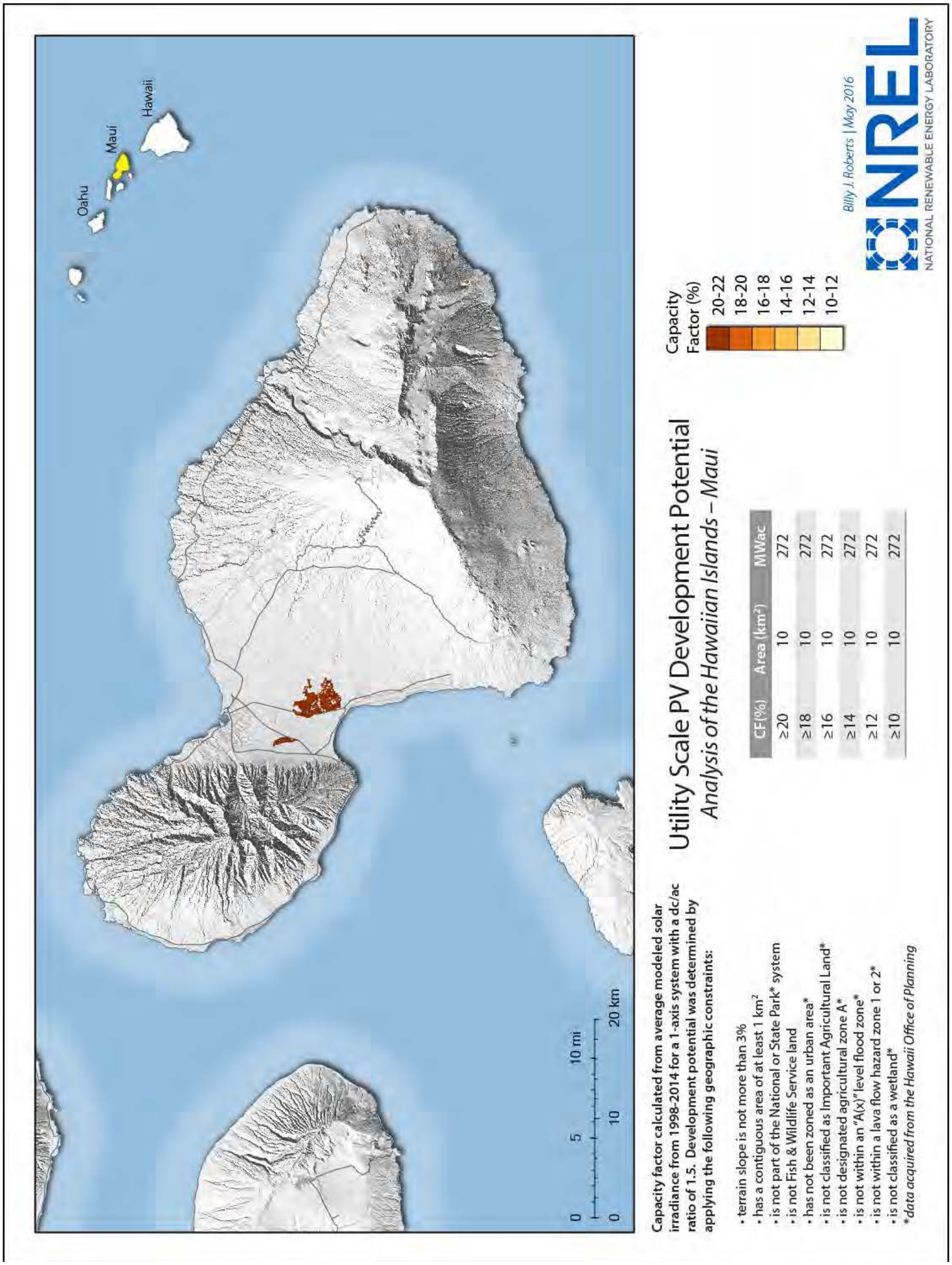


Figure F-14. Grid-Scale PV Development Potential for Maui (3% slope exclusion)

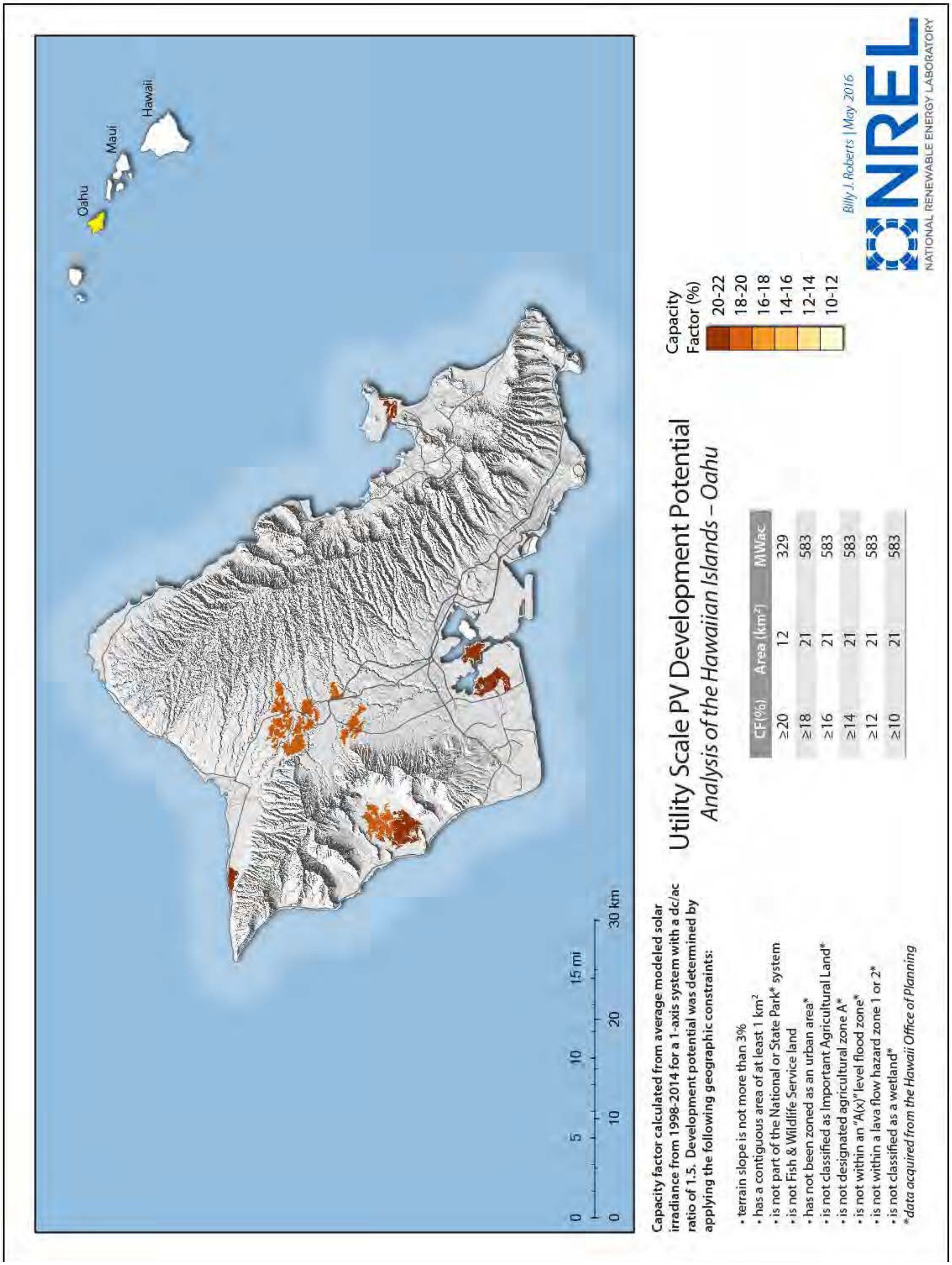


Figure F-15. Grid-Scale PV Development Potential for O'ahu (3% slope exclusion)

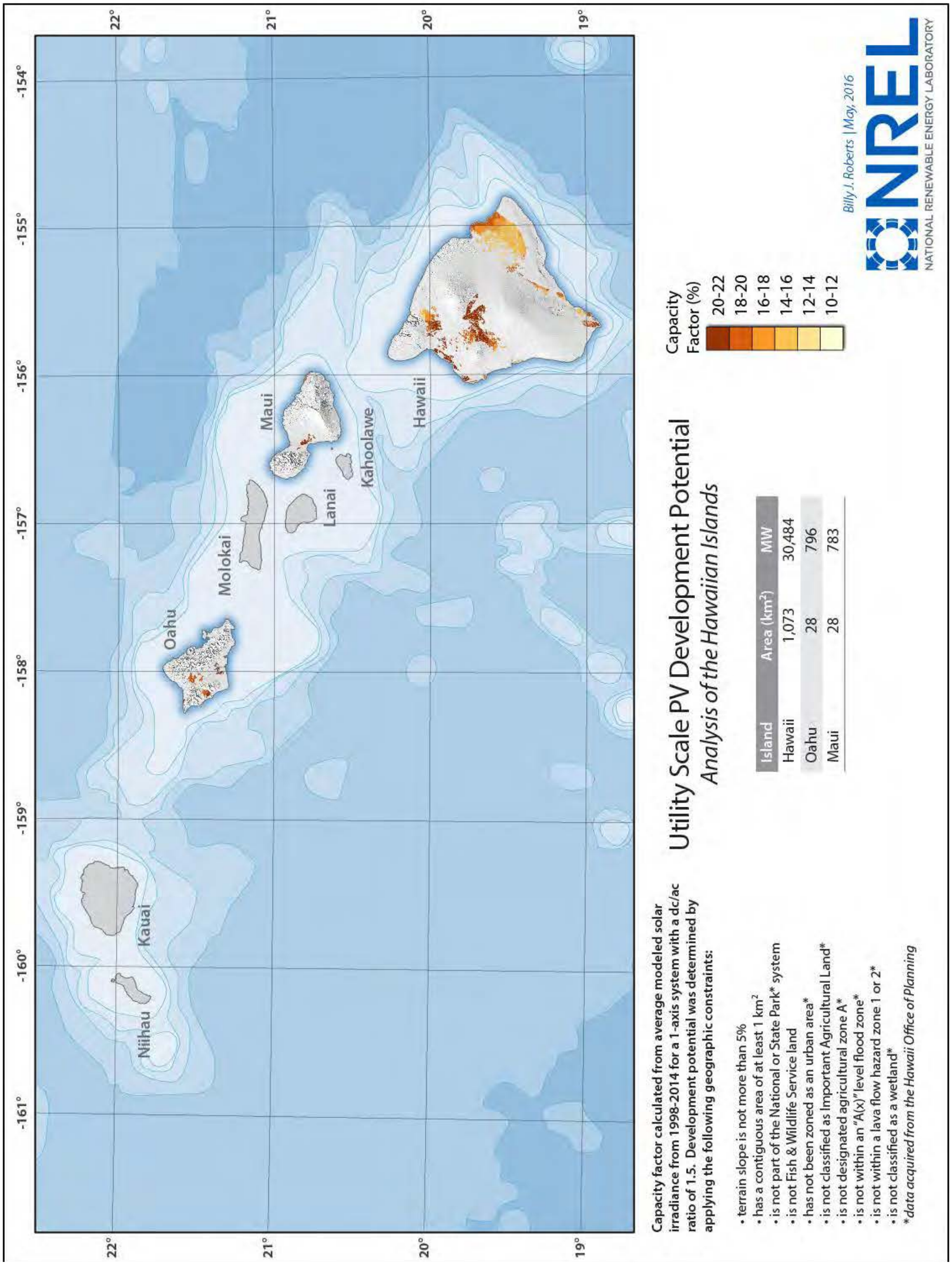


Figure F-16. Grid-Scale PV Development Potential for All Hawaiian Islands (5% slope exclusion)

F. NREL Reports

Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource

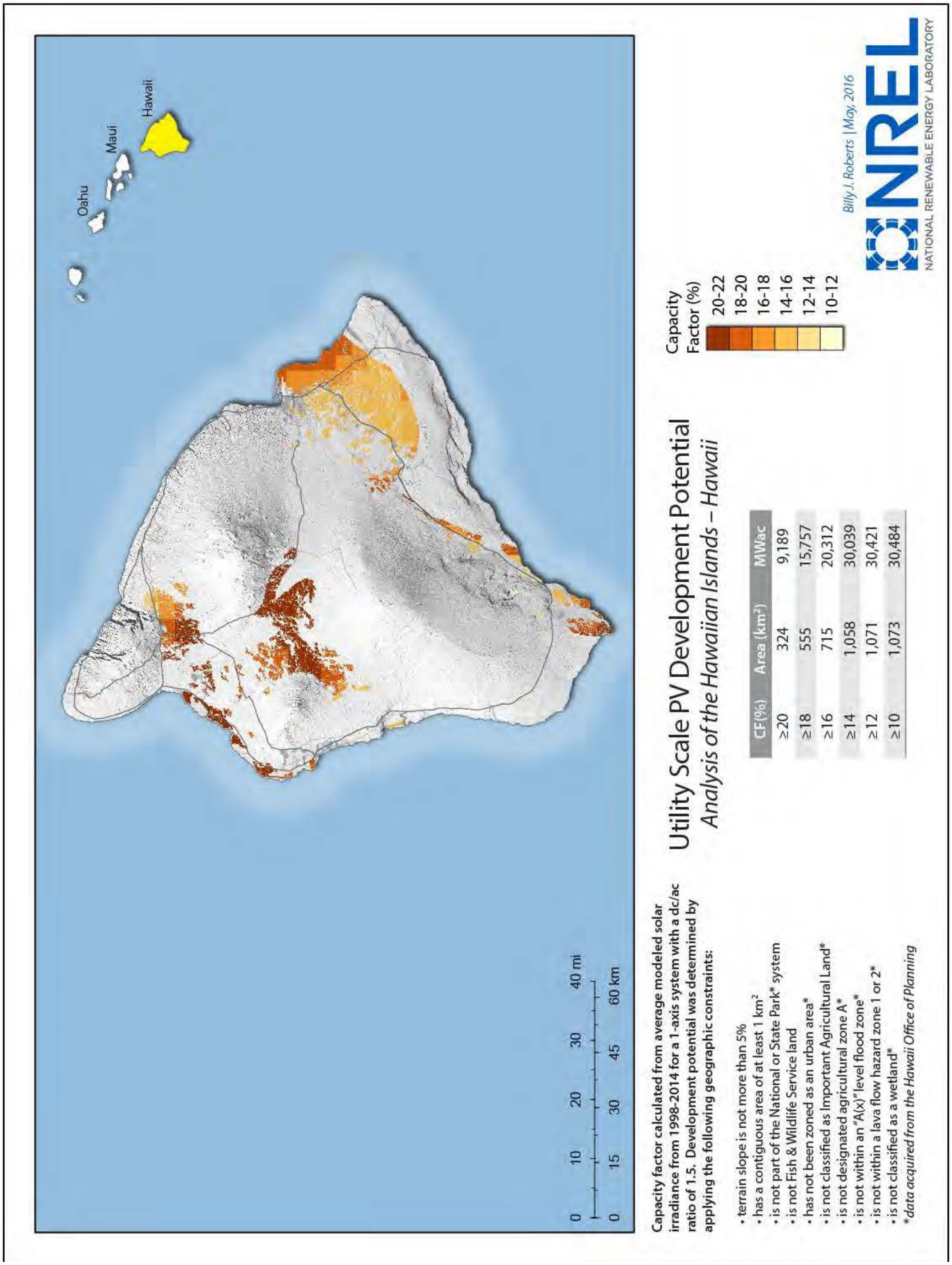


Figure F-17. Grid-Scale PV Development Potential for Hawai'i Island (5% slope exclusion)

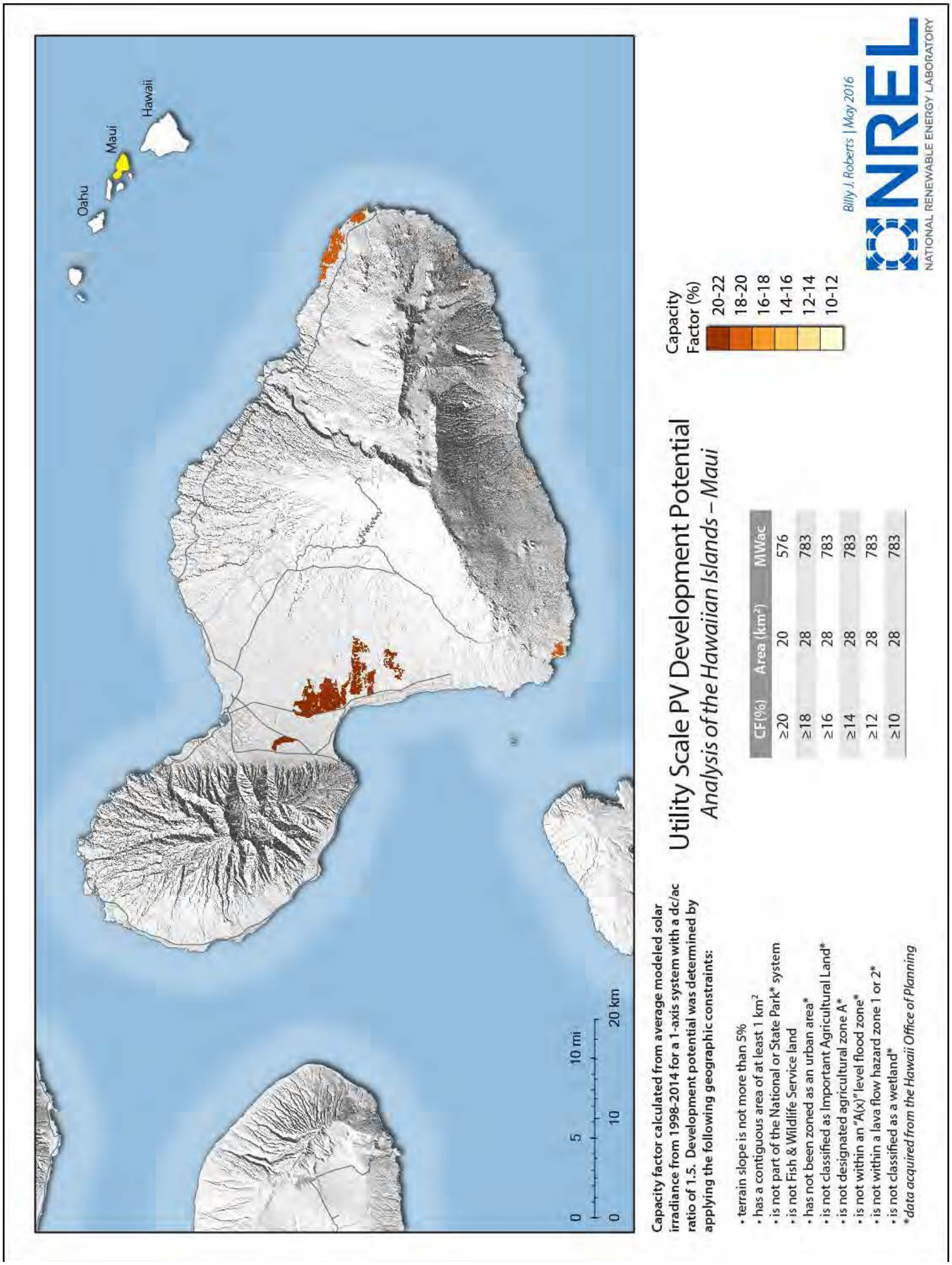


Figure F-18. Grid-Scale PV Development Potential for Maui (5% slope exclusion)

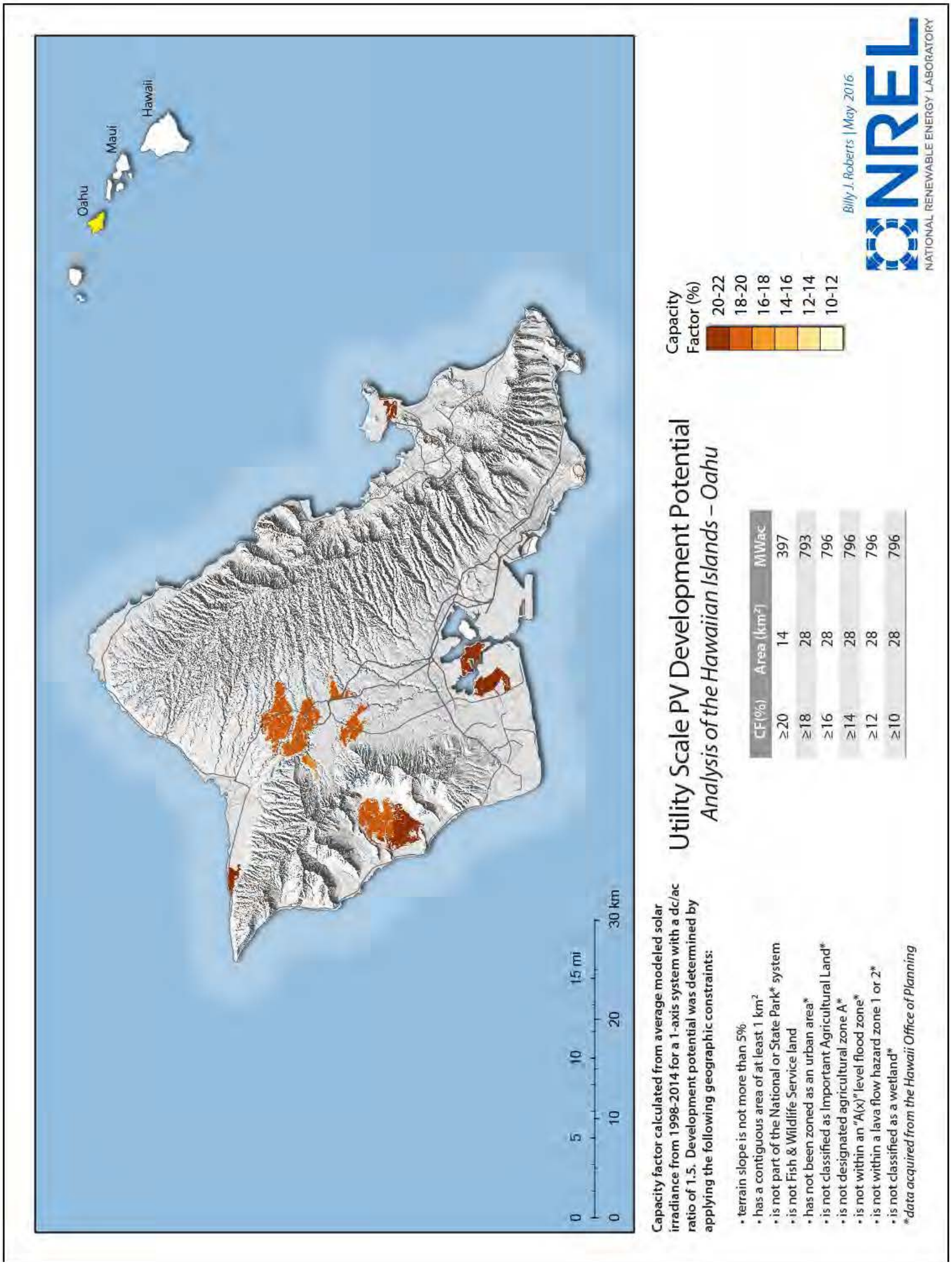


Figure F-19. Grid-Scale PV Development Potential for O'ahu (5% slope exclusion)

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

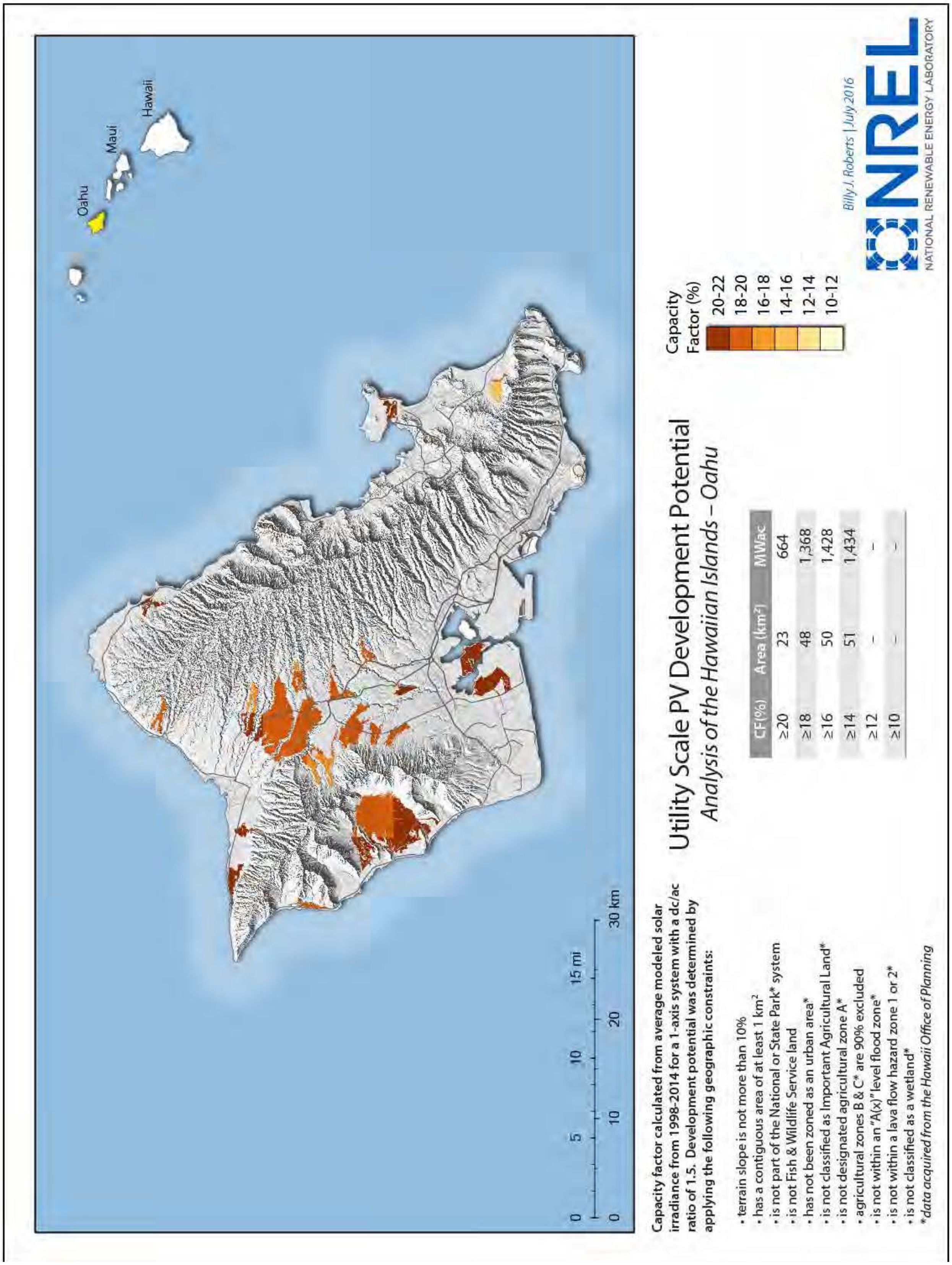


Figure F-20. Grid-Scale PV Development Potential for O'ahu (10% slope exclusion; Ag B and C class land 90% excluded)

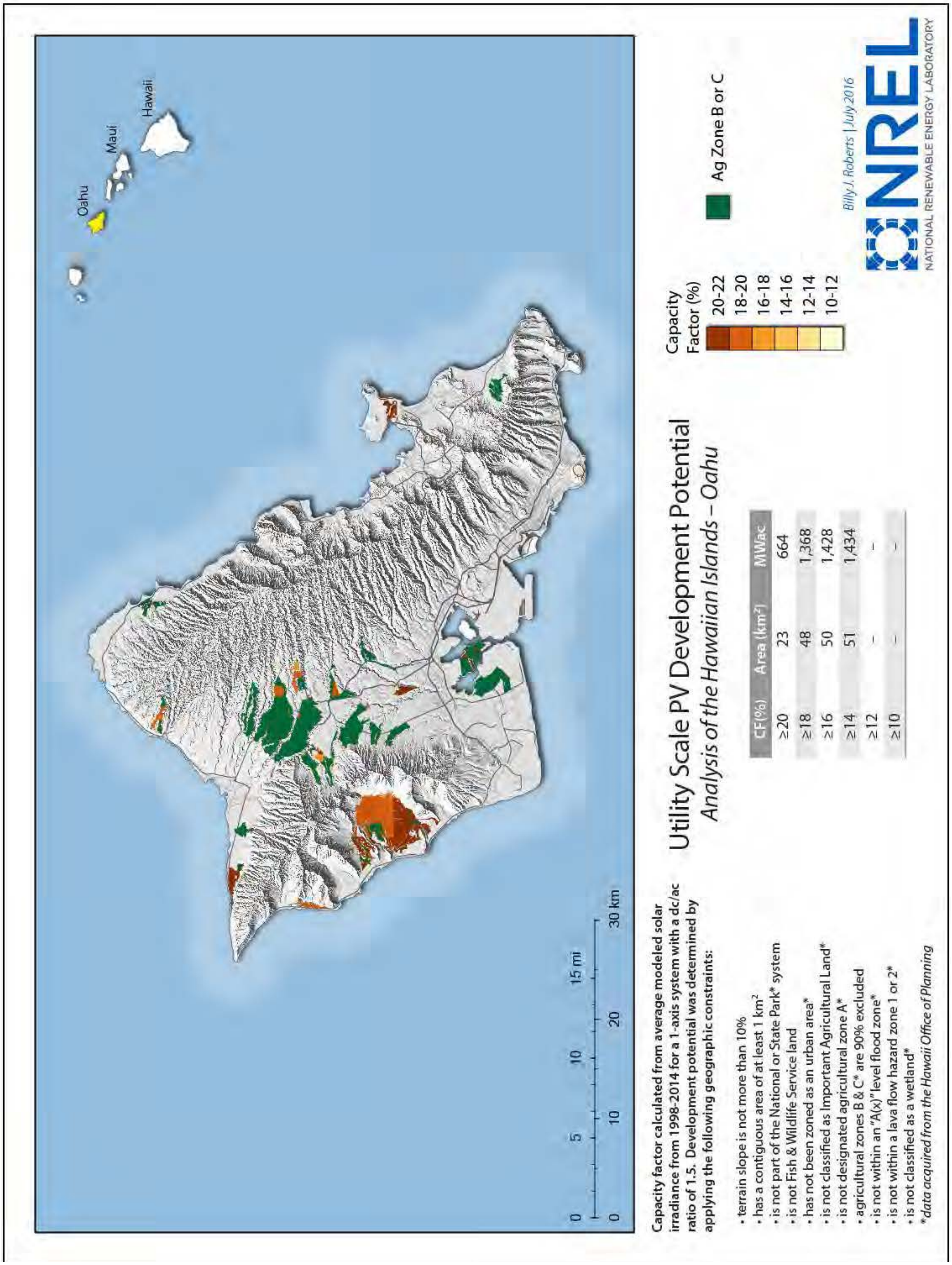


Figure F-21. Grid-Scale PV Development Potential for O'ahu (10% slope exclusion; Ag B and C class land highlighted)

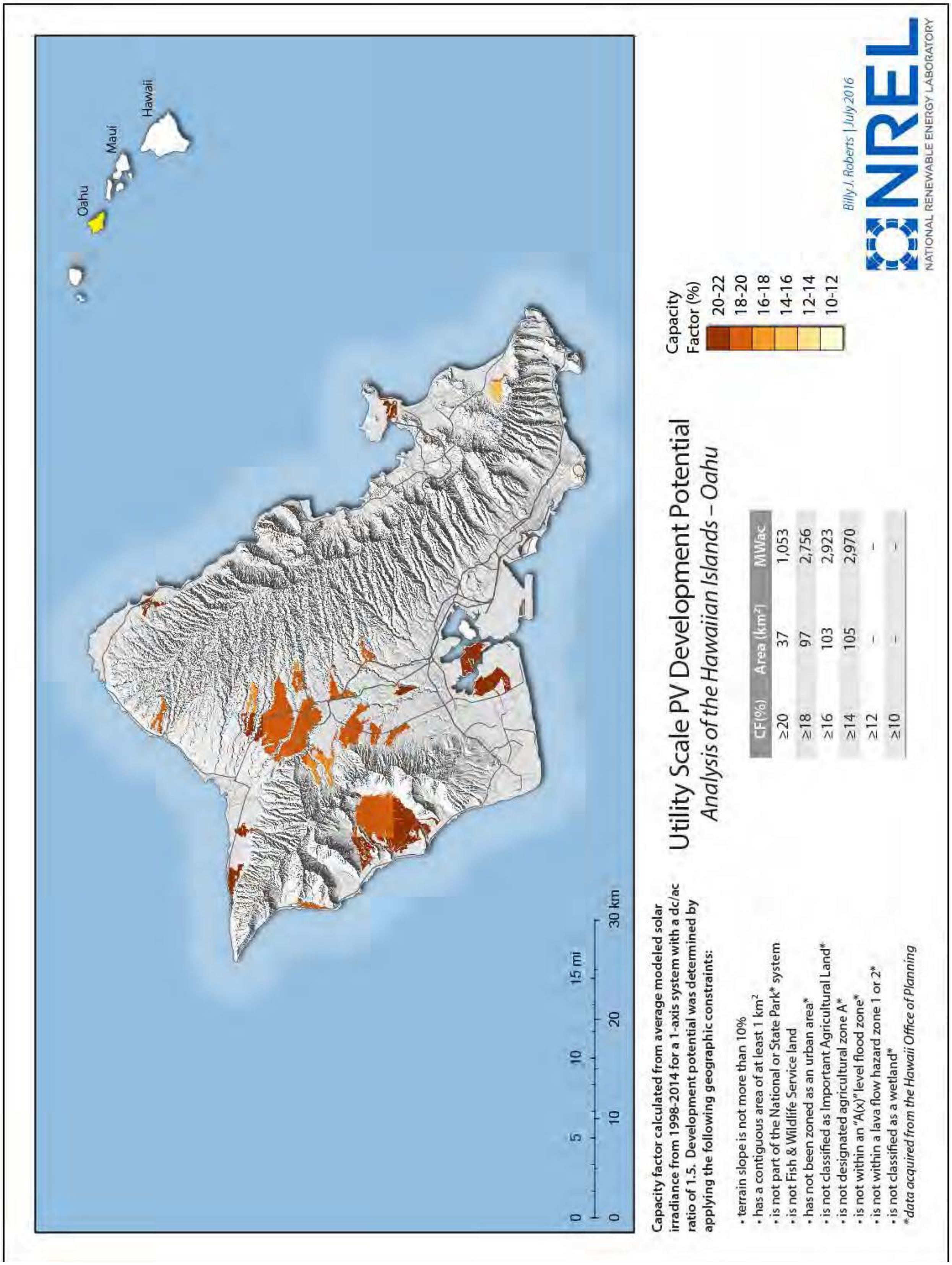


Figure F-22. Grid-Scale PV Development Potential for O'ahu (10% slope exclusion; Ag B and C class land included)

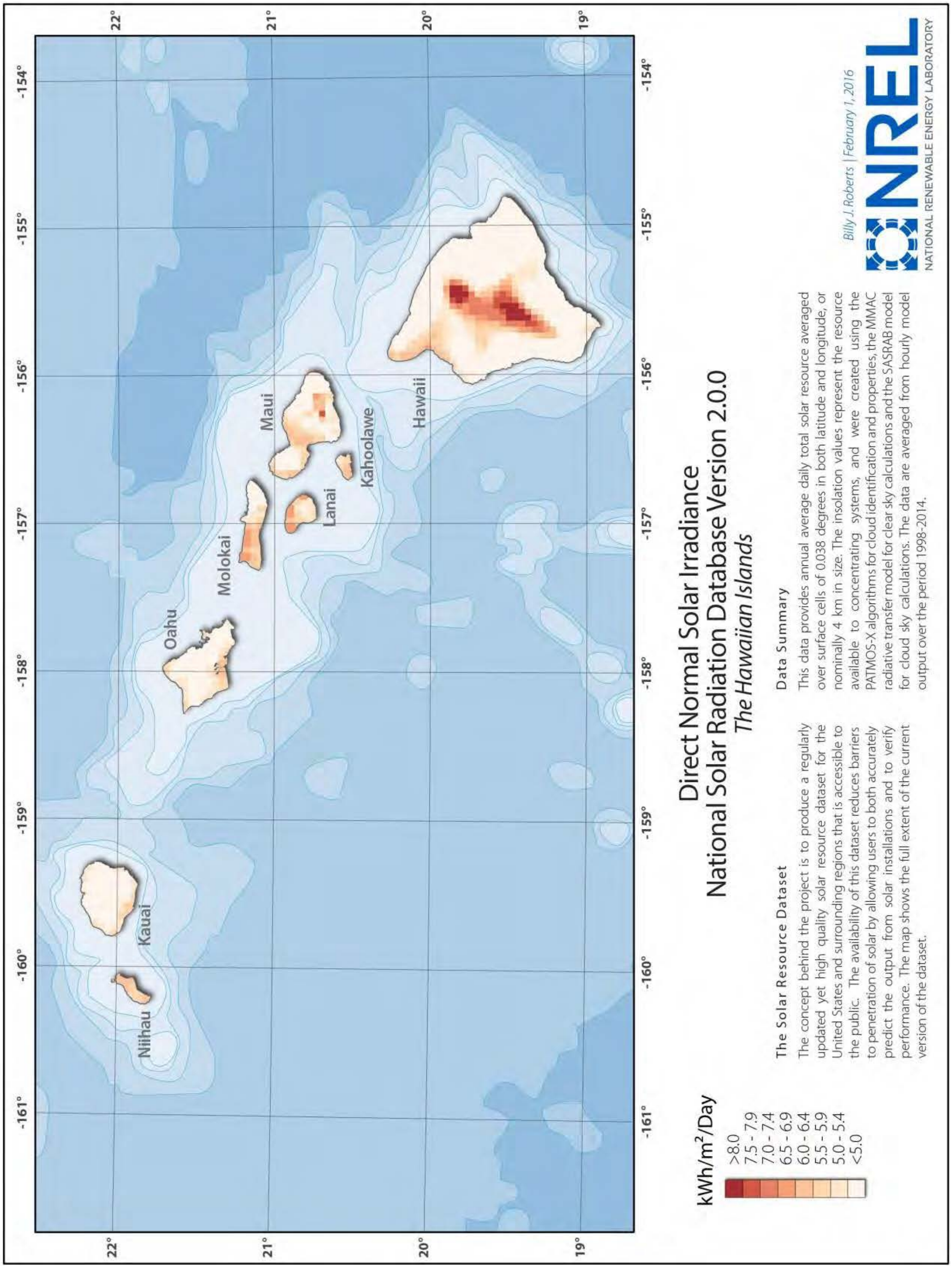
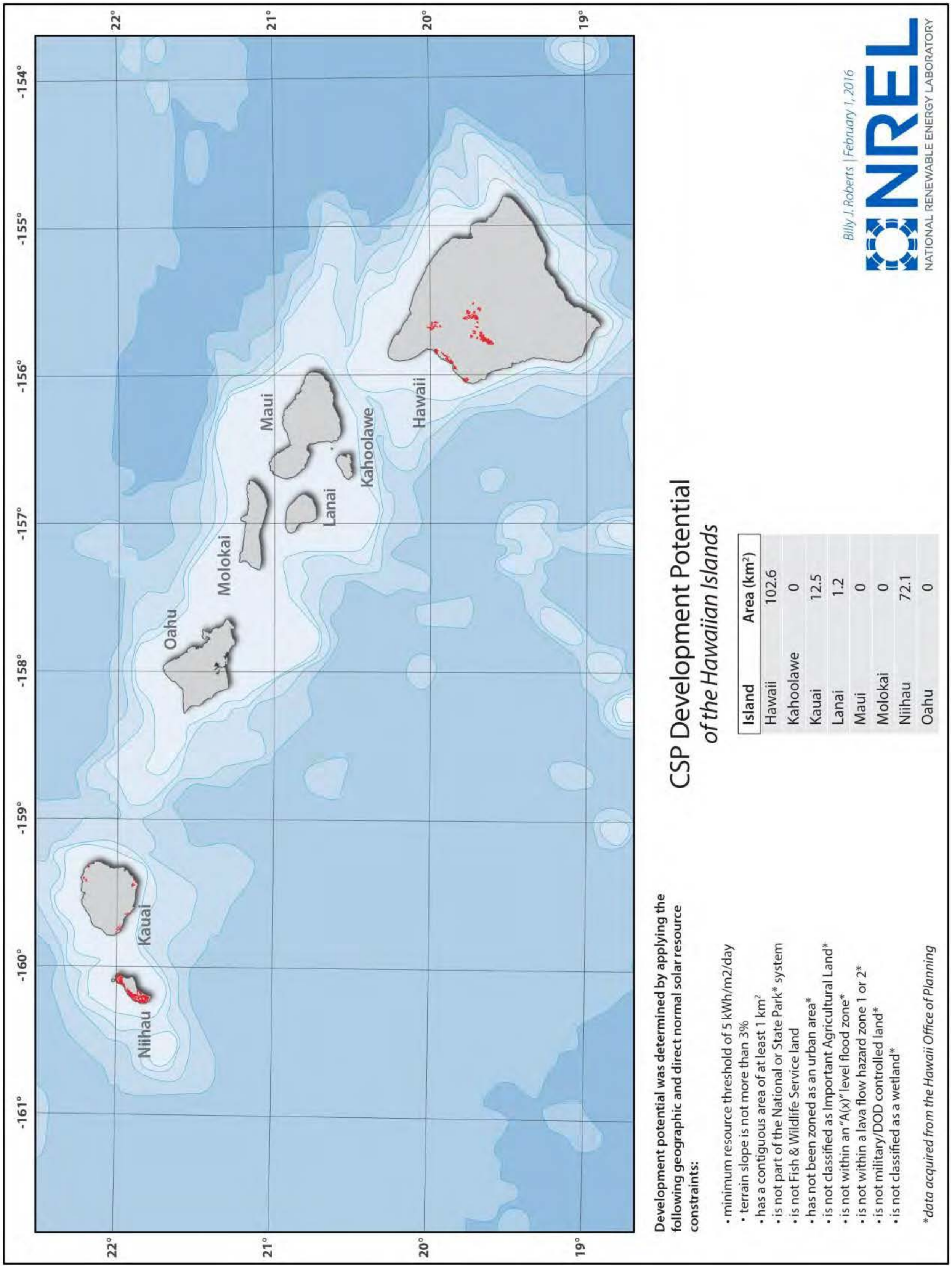


Figure F-23. Direct Normal Irradiance for All Hawaiian Islands



Island	Area (km²)
Hawaii	102.6
Kahoolawe	0
Kauai	12.5
Lanai	1.2
Maui	0
Molokai	0
Niihau	72.1
Oahu	0

Figure F-24. Concentrated Solar Power Development Potential for All Hawaiian Islands

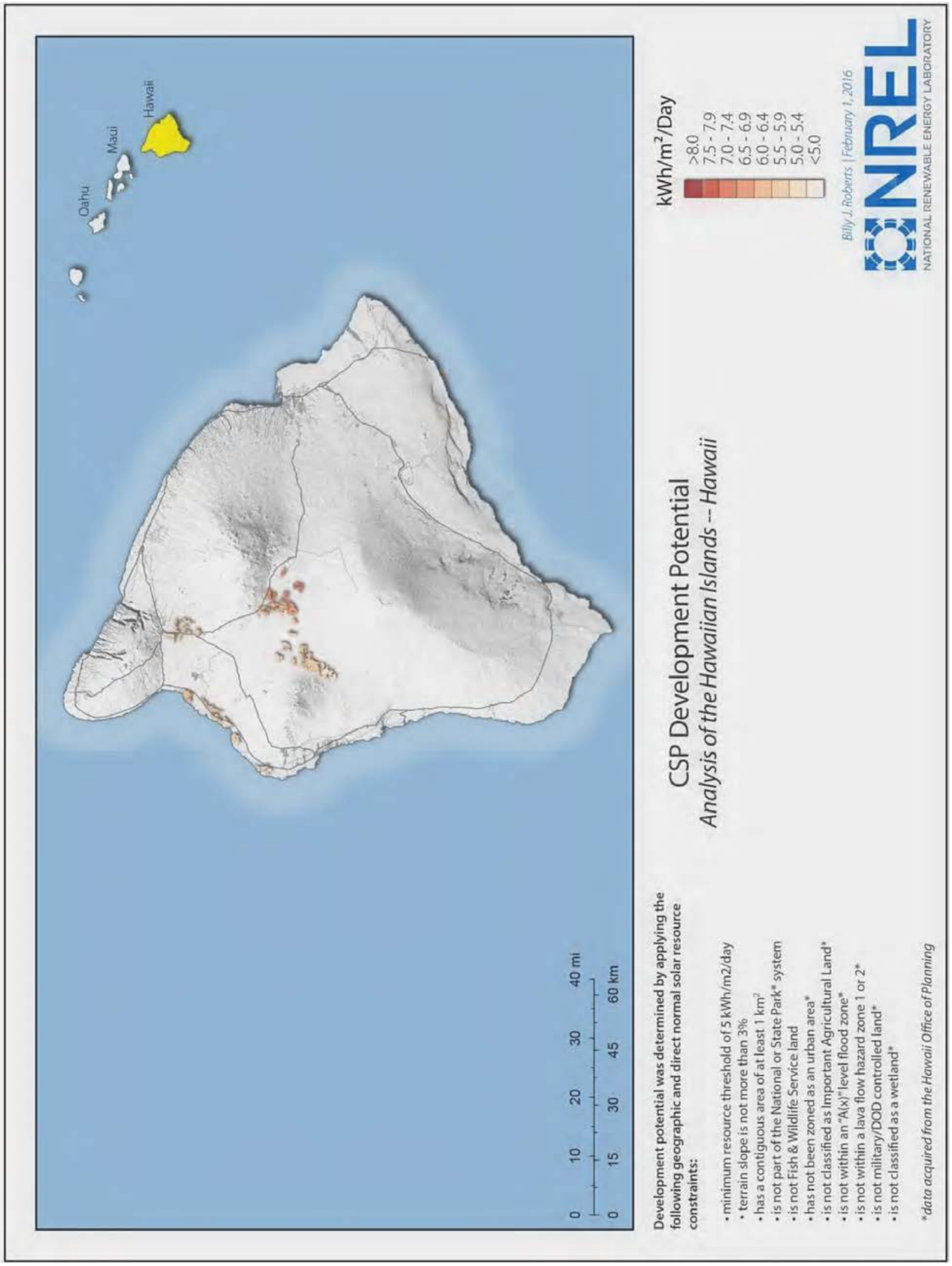


Figure F-25. Concentrated Solar Power Development Potential for Hawaiʻi Island

Appendix A: System Advisor Model (SAM) Parameters

System parameters	Value
self.system_capacity	10000
self.dc_ac_ratio	1.5
self.tilt	0
self.azimuth	180
self.inv_eff	96
self.losses	14.0757
self.array_type	2
self.gcr	0.4
self.adjust_constant	0

Table F-9. System Advisor Model (SAM) Parameters

Appendix B: Potential Updates & Differences with other Resource Potential Assessments

The assessment of utility-scale onshore wind, utility-scale PV, and CSP potential resources for Hawai‘i Island, Maui, and O‘ahu presented in this document is dependent on the data and assumption considered in the analysis. As mention in Dr. Hodge’s email of 10/26/2016, the differences between NREL’s analysis and the resource potential assessment performed by Dr. Fripp at the University of Hawai‘i are mainly due to the different land use availability assumptions.

The utility-scale onshore wind, utility-scale PV, and CSP resource potential assessment presented in this document could be further improved by analyzing every individual potential available site. This would require more detailed local information, such as current land use, ownership details, and potential social opposition.

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[2] Wind Vision: A New Era for Wind Power in the United States, U.S. Department of Energy, April 2015.

[3] National Solar Radiation Database (NSRDB), https://nsrdb.nrel.gov

[4] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Anderberg, M.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Product for Use in NREL's National Solar Radiation Database: Preprint." 6 pp. NREL/CP-5D00-62776.

[5] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Satellite Product for Use in NREL's National Solar Radiation Database: Preprint." 9 pp.; NREL/CP-5D00-62237.

[6] System Advisor Model, SAM 2014.1.14: General Description, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-61019.

[7] PVWatts Version 5 Manual, National Renewable Energy Laboratory, September 4, 2014.

[8] Land-Use Requirements for Solar Power Plants in the United States, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-56290, June 2013.

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AGGREGATED WIND POWER PROFILE TIME SERIES

This NREL study produced aggregated hourly, onshore wind power profiles for the Hawaiian Islands. The profiles were calculated at 80-meter and 100-meter hub heights based on wind speeds simulations using the Weather Research and Forecasting (WRF) model. The two simulations used a spatial resolution of 1.5 km square grid, a temporal resolution of one hour, and four 1.94 MW turbines in each grid. The use of two hub heights in the simulations enable a better direct comparison between two onshore wind scenarios. NREL based the wind hourly time series on 2014 data to coincide with the historical load shape used.

The wind power profiles take into account the Agricultural B and C class land exclusions discussed in Analysis 4 of the *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource* study (see page F-13).

While existing renewable energy wind projects use historical recorded data for modeling, future offshore wind projects will use these wind power profiles. Future onshore wind projects will use hourly profiles based on existing wind farms in the specific location that the resource could be added.

The original intent of this study was to develop an improved power profile time series that accounts for the diversity of sites included in the resource potential analysis. However, the analysis averaged all sites (that is, 6.5 meters per second, 7.5 meters per second, and 8.5 meters per second), resulting in capacity factors for Maui and Hawai‘i Island that were significantly lower than existing resources, and capacity factors for O‘ahu that were significantly higher than existing resources. To avoid inaccurately modeling the wind power profile time series for these three islands, we did not use these aggregated wind power profile time series in the December 2016 PSIP update for onshore wind. We did, however, use the aggregated wind power profile time series for O‘ahu for O‘ahu offshore wind.

Aggregated Wind Power Profile Time Series

Caroline Draxl
Ignacio Losada Carreno
Andrew Clifton
Carlo Brancucci Martinez-Anido

This report was prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on July 21, 2016.

Aggregated Wind Power Profile Times Series

Aggregated hourly onshore wind power profile time series are provided for 2 different scenarios for three Hawaiian Islands (Hawai‘i, Maui, and O‘ahu) for year 2014:

- 80-meter hub-height
- 100-meter hub-height

The onshore wind power profile time series are calculated from wind speeds (at 80- and 100-meter hub-heights) based on meteorological simulations using the Weather Research and Forecasting (WRF) model with a spatial resolution of 1.5 km x 1.5 km and a temporal resolution of 1 hour.

The two scenarios use the same reference 1.94 MW turbine (NREL, 2014) but at different hub heights. This will allow a better direct comparison between the two onshore wind scenarios. In order to assume a similar wind power density as in the resource assessment report (3 MW/km^2), it is assumed that only a maximum of four 1.94 MW turbines can fit in each grid point (1.5x1.5km), which corresponds to a power density of 3.45 MW/km^2. This number is also closer to the power density assumed in the WIND Toolkit (up to eight 2-MW turbines in a 2x2km cell). In other words, the maximum available land in a 1.5x1.5 km cell is 2.25 km^2 and up to four 1.94 MW wind turbines are allowed. If the available land is less than 2.25 km^2, zero, one, two, or three wind turbines are allowed depending on the available land.

The aggregated and normalized onshore wind power profile time series take into account the land exclusions of Analysis 4 (see NREL’s resource assessment conducted during the first phase of this study, “Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource”). Only sites with an average wind speed at 80-meter height equal or higher than 6.5 m/s in the REEDS data set (AWS Truepower, 2014) are considered. The sites that form the aggregated and normalized time series are shown in the onshore wind resource potential maps for Hawai‘i, Maui, and O‘ahu in NREL’s resource assessment mentioned above.

WRF Modeling

We used the Weather Research and Forecasting (WRF; Skamarock et al., 2008, www.wrf-model.org.) model to simulate wind speeds for Hawai‘i for the whole year of 2014. The WRF model is a community NWP model maintained by the National Center for Atmospheric Research (NCAR) in the United States. The advantage of a community model is that many users contribute with code updates and experiences, which makes it a well updated tool. It has been successfully applied to wind-energy-related studies and wind resource assessments (e.g., Draxl et al., 2014, Draxl et al., 2012; Draxl et al., 2013; Storm and Basu, 2010; Phadke et al., 2011; Dvorak et al., 2012; Carvalho et al., 2013; Carvalho et al., 2014; Santos-Alamillos et al., 2013; Garcia-Diez et al., 2012; Ji-Hang et al., 2014; Lundquist et al., 2014). The WRF model allows for accurate simulations of winds near the surface and at heights that are important for wind energy purposes. WRF’s ability to downscale to required resolutions allows for modelling small-scale features, such as fronts, sea breezes, or winds influenced by orography, which are all important factors in describing the wind characteristics over Hawai‘i.

For this project, data were simulated over Hawai‘i at multiple heights at a hourly temporal resolution. To achieve a high resolution of 1.5 km, data were downscaled from the Climate Forecast System Re-analyses from the National Center for Environmental Predictions (NCEP), using three modeling domains. The outermost domain has a grid spacing of 37.5 km, and the two inner domains have a 7.5 km and 1.5 km grid spacing (Figure F-26). Sea Surface Temperatures from NCEP were also used as boundary conditions to improve the simulations. The model was restarted every day at 12 UTC, and the first 12 hours were discarded due to model spin up. Data were linearly interpolated to hub heights of 80 and 100m.

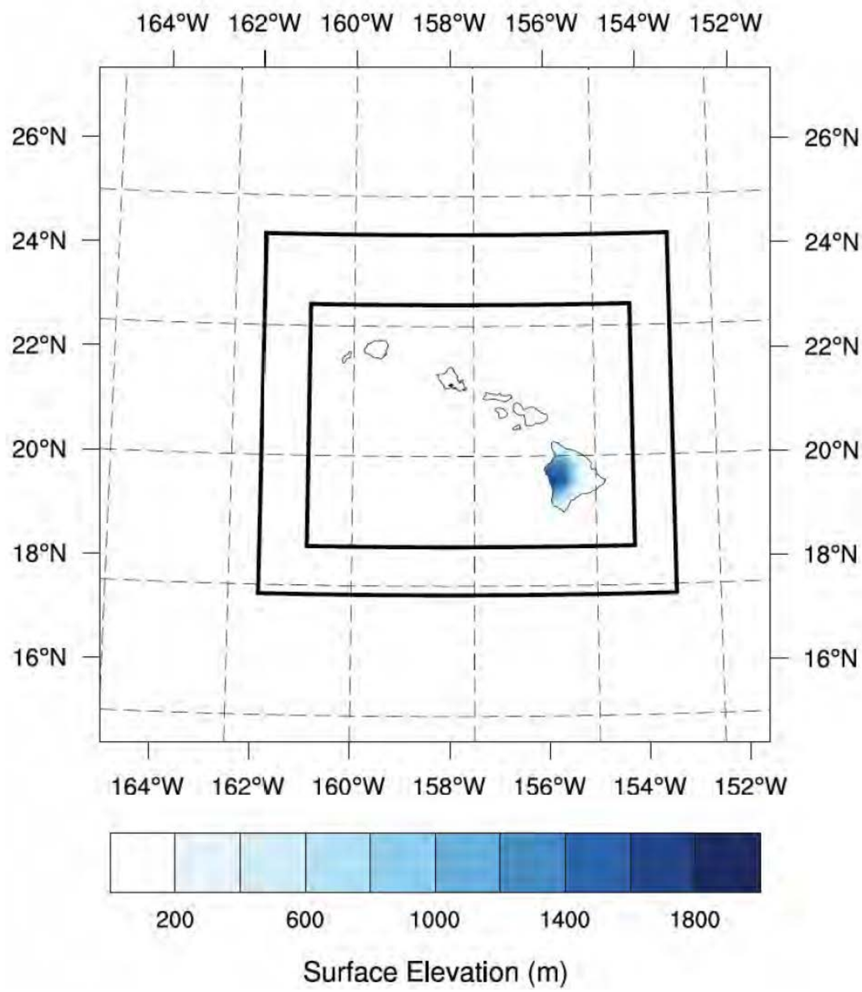

Figure F-26. Weather Research and Forecasting Modeling Domains Over Hawai‘i

Hawai‘i being a chain of islands in the middle of the Pacific, it is exposed to occasionally high winds in excess of 30 m/s, especially on or near mountain tops or mountain passes. Because of the variations in the terrain, wind speeds can vary from one location to the next. Specifically, in the year 2014, the Hawaiian Islands were hit by two hurricanes, one in August and one in October. Figure F-27 shows snapshots of the U and V wind components during the October hurricane on October 19 as an example of how the WRF model is able to simulate extreme weather. Figure F-28 shows precipitation during the same time.

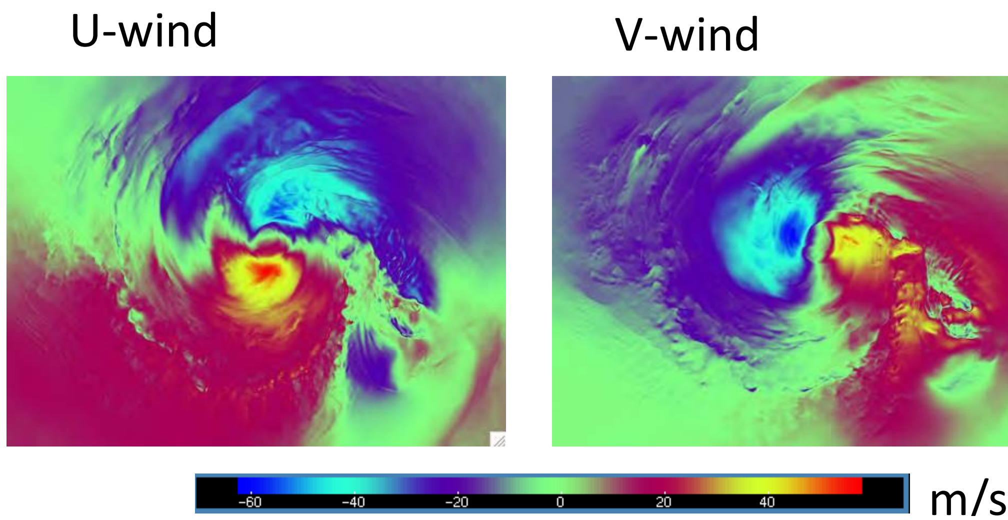

Figure F-27. U and V Wind Component from WRF Simulations on October 19, 2014 at 90 Meters Over the Hawaiian Islands

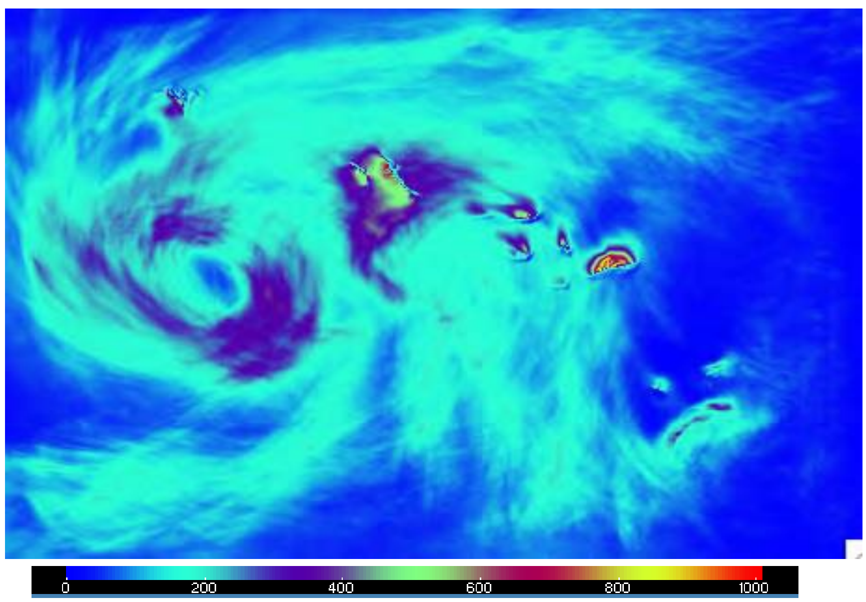

Figure F-28. Precipitation Over the Hawaiian Islands at a Specific Time on October 19, 2014 (mm of precipitation)

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AGGREGATED SOLAR POWER PROFILE TIME SERIES

This NREL study produced aggregated hourly solar power time series profiles for the Hawaiian Islands. The next page lists the eight different axis-tracking scenarios analyzed—four for all available sites and four for selected sites based on our request—for O'ahu, Maui, and Hawai'i Island.

NREL derived these time series profiles using NREL's mean solar radiation data compiled from 1998 to 2014. The solar radiation data used a spatial resolution of a four-kilometer square grid (four km x four km) with temporal resolution of 30 minutes. NREL based the solar hourly time series on 2014 data to coincide with the historical load shape used.

While existing renewable energy solar projects use historical recorded data for modeling, all future grid-scale solar projects will use these NREL power profile time series.

The December PSIP Update modeling, to the extent feasible, used this NREL data in our analysis to best analyze potential resource options.

Aggregated Solar Power Profile Time Series

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Ignacio Losada Carreno
Billy Roberts
Carlo Brancucci Martinez-Anido

This report was prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on July 12, 2016.

Aggregated Solar Power Profile Time Series

Aggregated normalized hourly solar power profile time series (values are provided in ac-energy/ac-capacity terms as requested by the Hawaiian Electric Companies) are provided for eight different scenarios for three Hawaiian Islands (Hawai‘i, Maui, and O‘ahu) for year 2014 as well as for 16 different years (1998–2013):

- All available sites
  - Fixed tilt (20°), DC/AC = 1.2
  - Fixed tilt (20°), DC/AC = 1.5
  - Single-axis tracking, DC/AC = 1.2
  - Single-axis tracking, DC/AC = 1.5

- Selected available sites based on the Companies’ requests
  - Fixed tilt (20°), DC/AC = 1.2
  - Fixed tilt (20°), DC/AC = 1.5
  - Single-axis tracking, DC/AC = 1.2
  - Single-axis tracking, DC/AC = 1.5

The aggregated time series for each scenario for each of the three islands are provided in the file “Solar_Power_Time_Series.zip”. The file also includes the coordinates of all the available for each island as well as the selected ones based on the Companies’ requests.

Mean solar radiation data over the years 1998 to 2014 was taken from the latest National Solar Radiation Database (NSRDB) [1–3] which has a spatial resolution of 4 km x 4 km and a temporal resolution of 30 minutes. NSRDB is a serially complete collection of meteorological and solar irradiance data sets. The database is managed and updated using the latest methods of research by a specialized team of forecasters at the National Renewable Energy Laboratory (NREL). The data spans 1998–2014 and the latest version now uses satellite retrievals. The System Advisor Model (SAM) [4] was used to attain solar power profile time series. SAM is a performance and financial model which makes performance predictions for grid-connected power projects based on parameters specified by the user [5].

The aggregated solar power profile time series take into account the land exclusions of Analysis 4 (see NREL's resource assessment conducted during the first phase of this study, "Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource") with a maximum slope of 5%. The capacity-weighted average land use for a fixed tilt small PV plant was taken to be 7.6 acres/MWac, while for a 1-axis small PV plant was taken to be 8.7 acres/MWac [6].

Solar Resource Inter-Annual Variability Analysis

The inter-annual solar resource variability analysis for each island differs depending on the scenario. The next three sections provide tables and figures comparing the solar resource variability between 17 years (1998-2014) for each island for different scenarios.

For all figures (Figure F-29 through Figure F-52) all use a DC/AC= 1.2 conversion factor.

3.1 Hawai'i Island

Year	All sites				Selected sites			
	1-axis tracking		Fixed tilt (20°)		1-axis tracking		Fixed tilt (20°)	
	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5
1998	0.219	0.267	0.183	0.226	0.257	0.311	0.208	0.256
1999	0.221	0.268	0.183	0.226	0.261	0.315	0.211	0.259
2000	0.229	0.279	0.191	0.236	0.265	0.323	0.217	0.267
2001	0.228	0.278	0.190	0.235	0.261	0.317	0.212	0.262
2002	0.224	0.275	0.188	0.233	0.255	0.312	0.210	0.259
2003	0.234	0.287	0.194	0.240	0.265	0.322	0.214	0.264
2004	0.227	0.278	0.187	0.232	0.251	0.307	0.204	0.253
2005	0.230	0.281	0.191	0.236	0.261	0.317	0.211	0.261
2006	0.215	0.264	0.180	0.223	0.249	0.304	0.203	0.251
2007	0.225	0.274	0.185	0.229	0.255	0.309	0.205	0.253
2008	0.224	0.274	0.186	0.230	0.246	0.299	0.200	0.247
2009	0.215	0.265	0.181	0.224	0.248	0.304	0.203	0.251
2010	0.233	0.284	0.193	0.238	0.265	0.320	0.213	0.262
2011	0.217	0.266	0.182	0.225	0.245	0.300	0.201	0.249
2012	0.219	0.268	0.183	0.226	0.253	0.307	0.205	0.252
2013	0.222	0.271	0.183	0.227	0.250	0.304	0.202	0.250
2014	0.224	0.275	0.185	0.230	0.246	0.300	0.200	0.248
Average (1998-2014)	0.224	0.274	0.186	0.230	0.255	0.310	0.207	0.256

Table F-10. Capacity Factor for Each Scenario and Each Year: Hawai'i Island

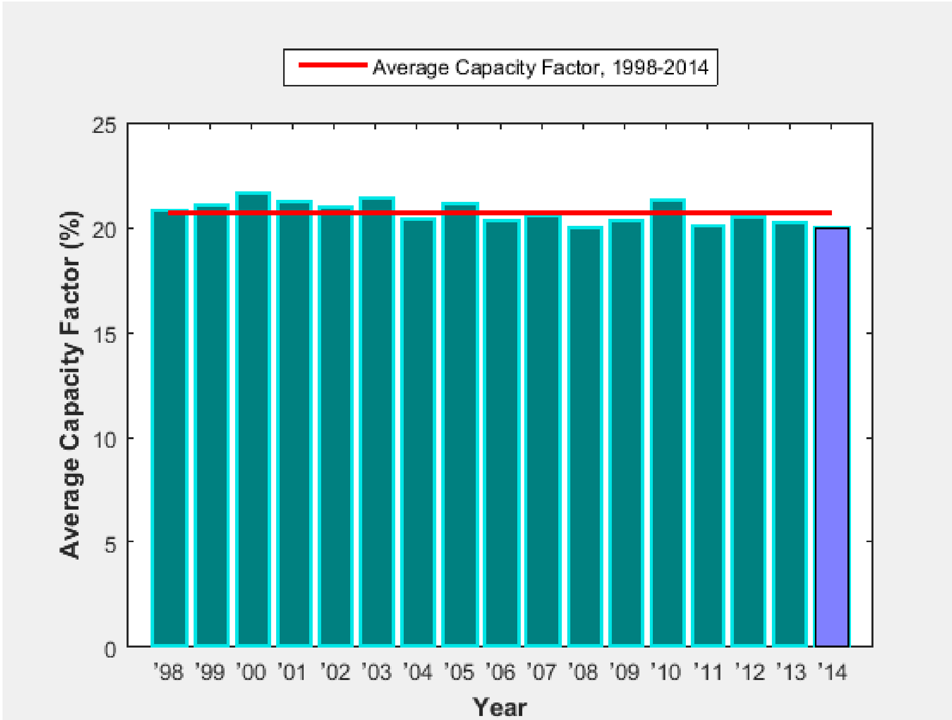

Figure F-29. Average Capacity Factor (selected sites, fixed tilt): Hawai'i Island

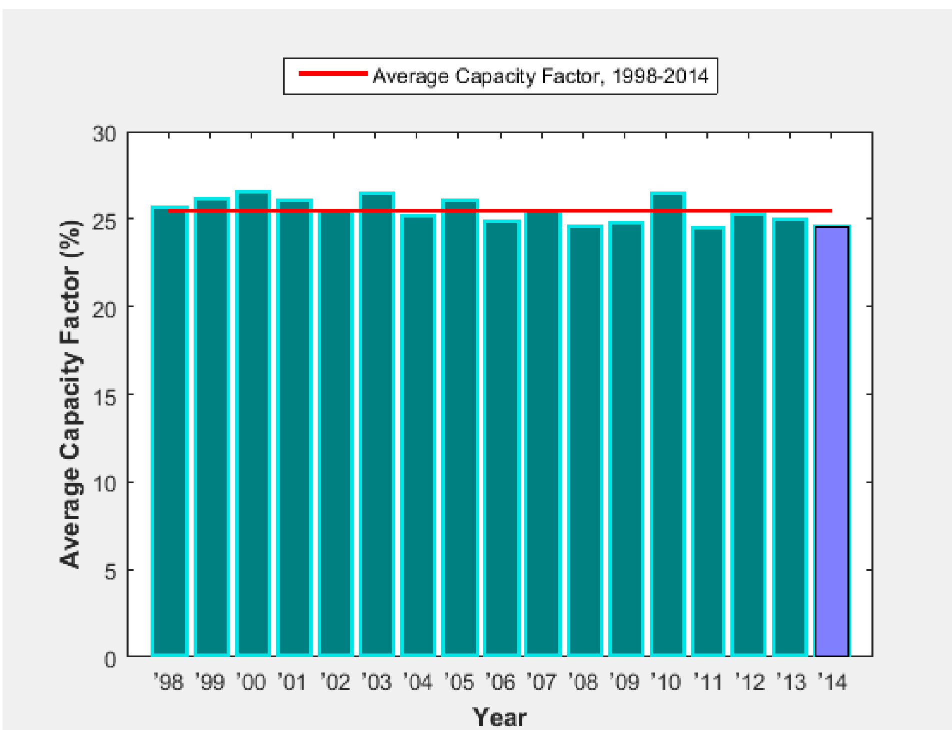

Figure F-30. Average Capacity Factor (selected sites, one-axis tracking): Hawai'i Island

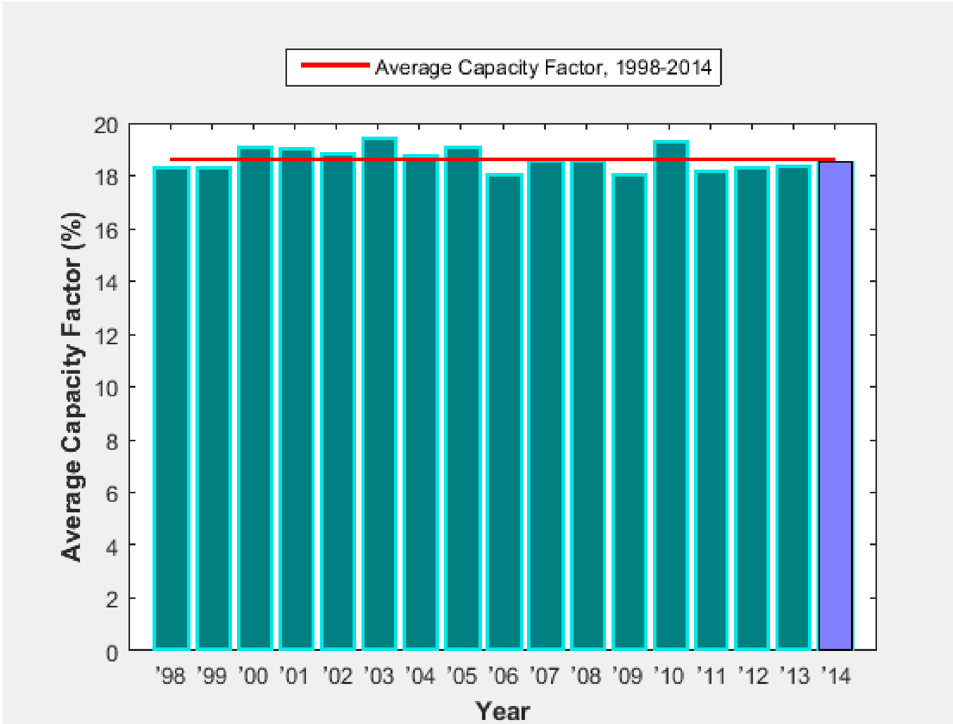

Figure F-31. Average Capacity Factor (all sites, fixed tilt): Hawai'i Island

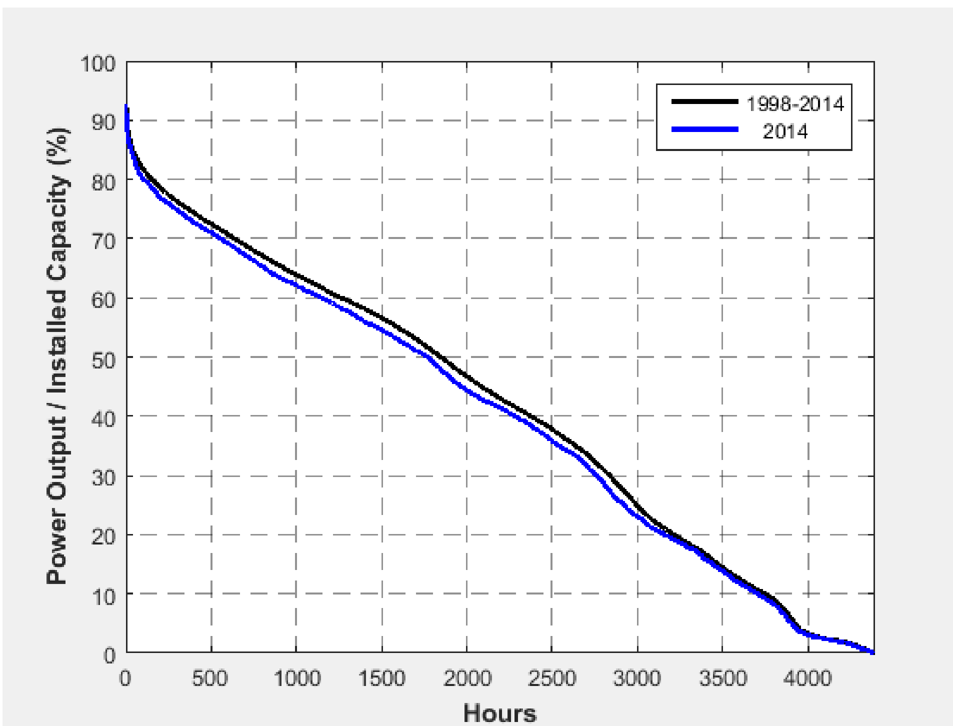

Figure F-32. Load Duration Curve—Power Output/Installed Capacity (selected sites, fixed-tilt): Hawai'i Island

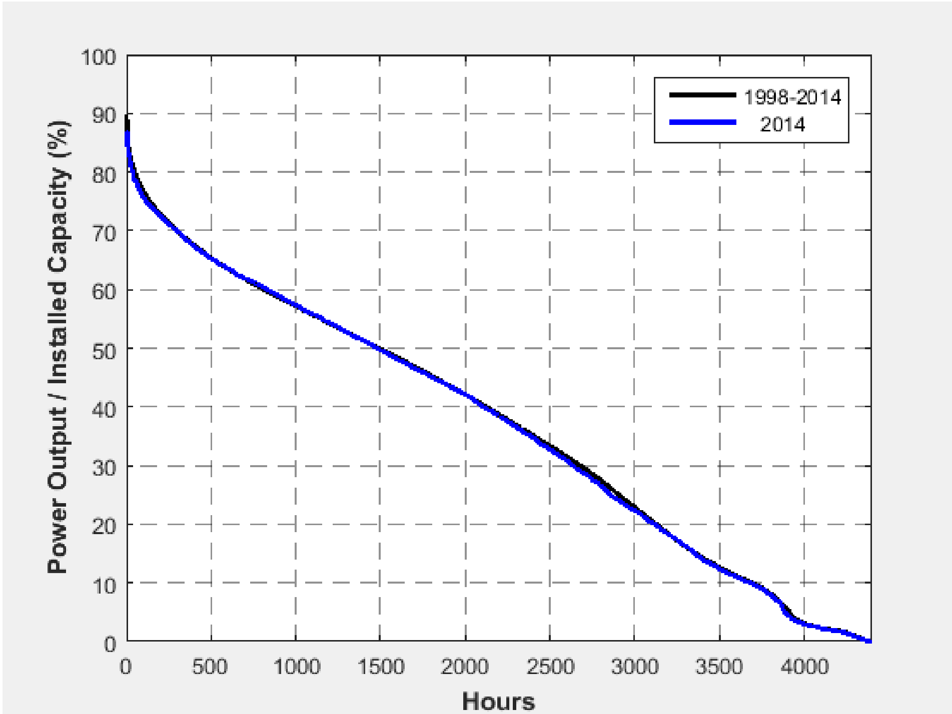

Figure F-33. Load Duration Curve—Power Output/Installed Capacity (all sites, fixed-tilt): Hawai'i Island

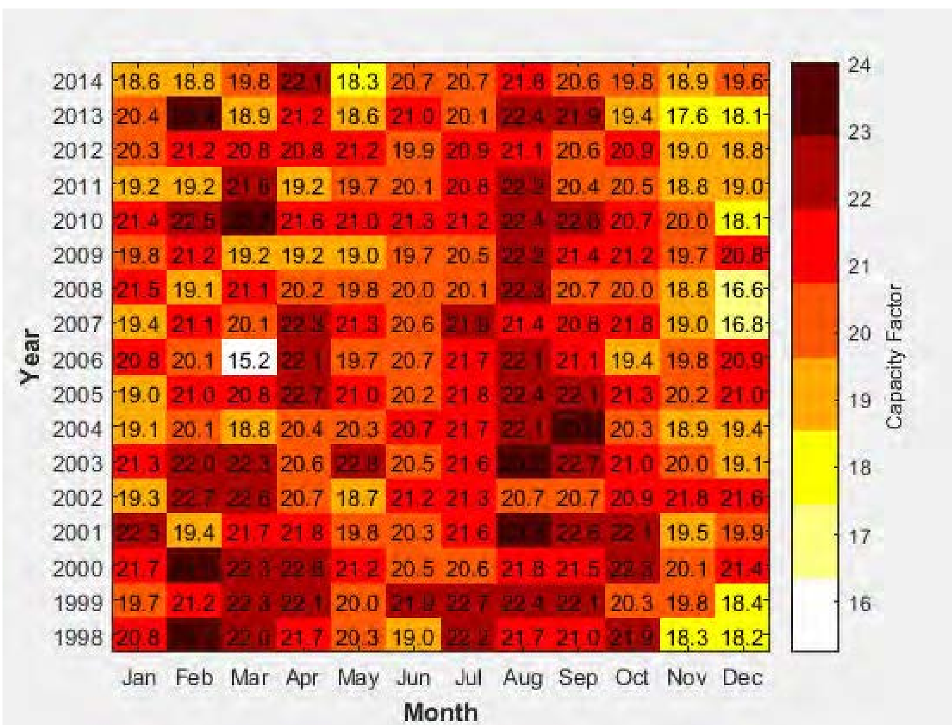

Figure F-34. Heat Map of Average Capacity Factor (selected sites, fixed tilt): Hawai'i Island

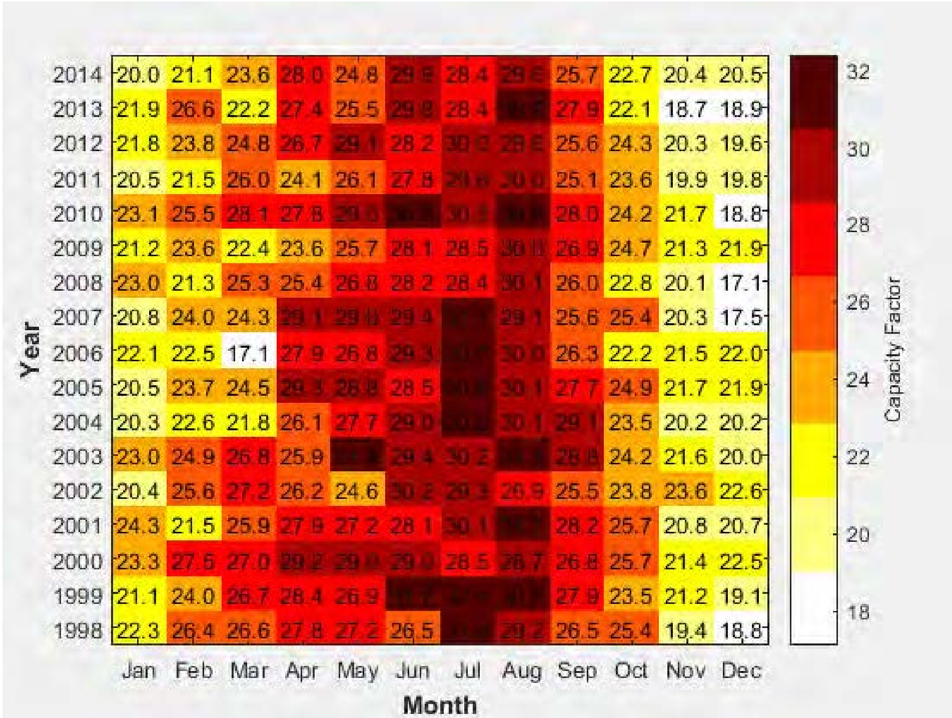

Figure F-35. Heat Map of Average Capacity Factor (selected sites, one-axis tracking): Hawai'i Island

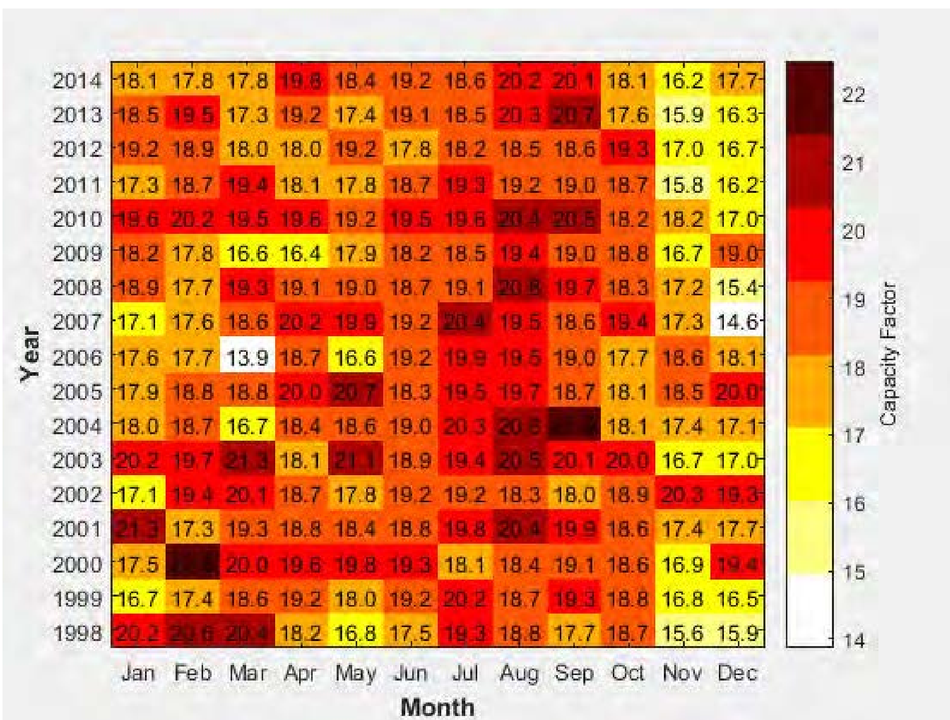

Figure F-36. Heat Map of Average Capacity Factor (all sites, fixed tilt): Hawai'i Island

3.2 Maui

Year	All sites				Selected sites			
	1-axis tracking		Fixed tilt (20°)		1-axis tracking		Fixed tilt (20°)	
	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5
1998	0.260	0.317	0.211	0.261	0.279	0.340	0.224	0.276
1999	0.272	0.330	0.219	0.270	0.284	0.345	0.226	0.279
2000	0.273	0.334	0.222	0.274	0.286	0.349	0.229	0.283
2001	0.267	0.327	0.218	0.269	0.281	0.343	0.226	0.280
2002	0.259	0.319	0.213	0.264	0.270	0.332	0.220	0.272
2003	0.271	0.331	0.219	0.270	0.283	0.345	0.226	0.279
2004	0.263	0.321	0.211	0.262	0.271	0.332	0.217	0.269
2005	0.270	0.329	0.218	0.269	0.280	0.342	0.224	0.277
2006	0.257	0.314	0.209	0.259	0.273	0.333	0.219	0.271
2007	0.258	0.316	0.209	0.258	0.275	0.336	0.219	0.271
2008	0.259	0.317	0.209	0.259	0.272	0.332	0.217	0.269
2009	0.257	0.316	0.210	0.260	0.273	0.335	0.220	0.273
2010	0.268	0.326	0.215	0.266	0.285	0.347	0.226	0.279
2011	0.253	0.310	0.208	0.257	0.268	0.328	0.217	0.269
2012	0.266	0.324	0.214	0.264	0.281	0.342	0.224	0.277
2013	0.263	0.321	0.213	0.263	0.275	0.337	0.221	0.273
2014	0.260	0.318	0.209	0.260	0.268	0.328	0.215	0.267
Average (1998-2014)	0.263	0.322	0.213	0.264	0.277	0.338	0.222	0.274

Table F-11. Capacity Factor for Each Scenario and Each Year: Maui

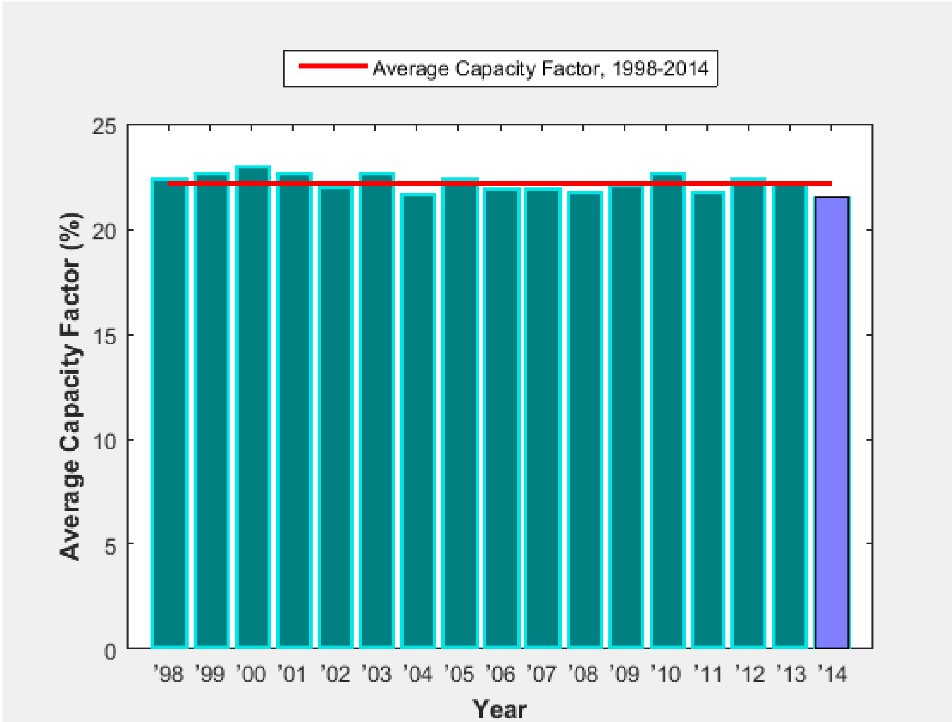

Figure F-37. Average Capacity Factor (selected sites, fixed tilt): Maui

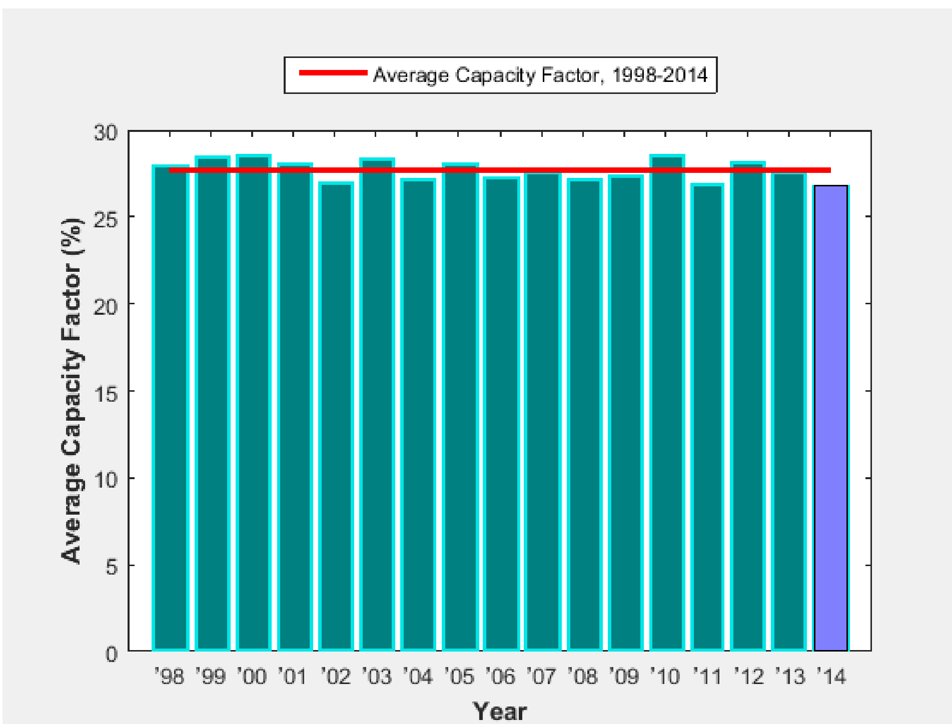

Figure F-38. Average Capacity Factor (selected sites, one-axis tracking): Maui

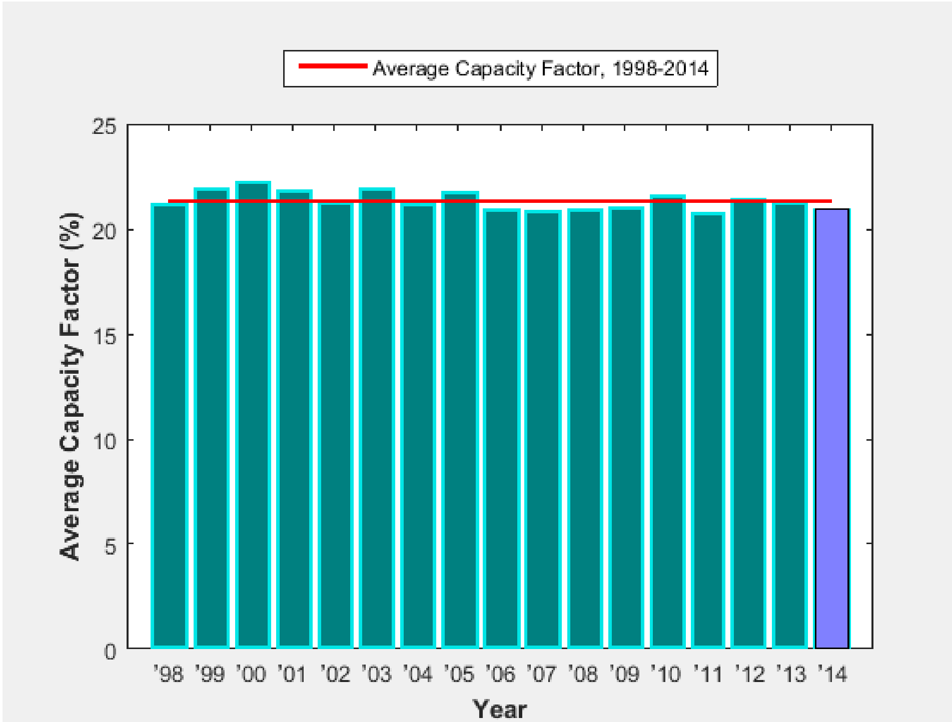

Figure F-39. Average Capacity Factor (all sites, fixed tilt): Maui

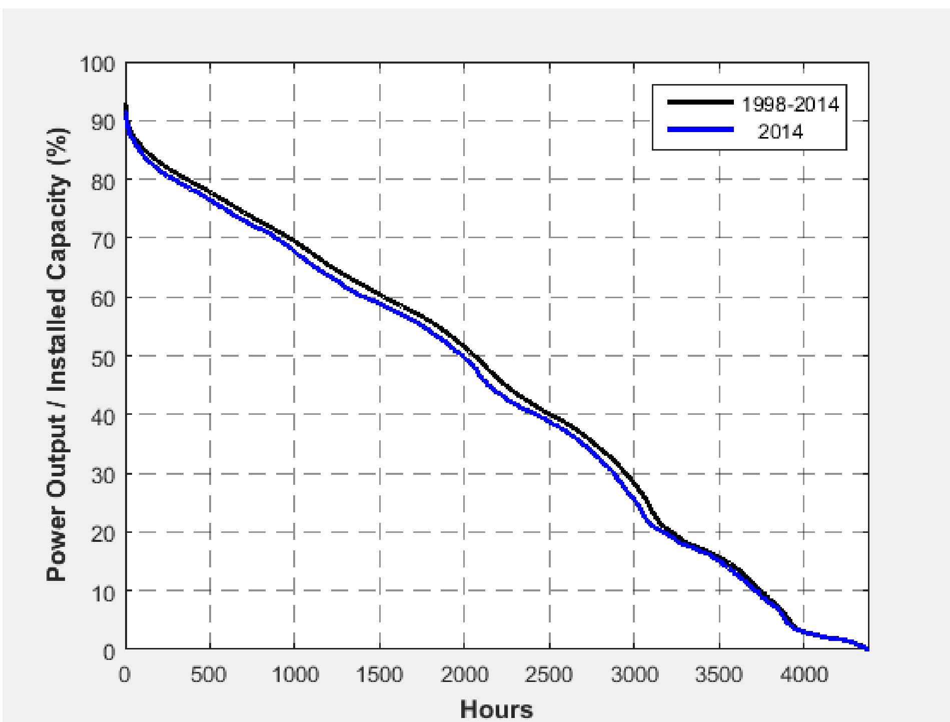

Figure F-40. Load Duration Curve—Power Output/Installed Capacity (selected sites, fixed-tilt): Maui

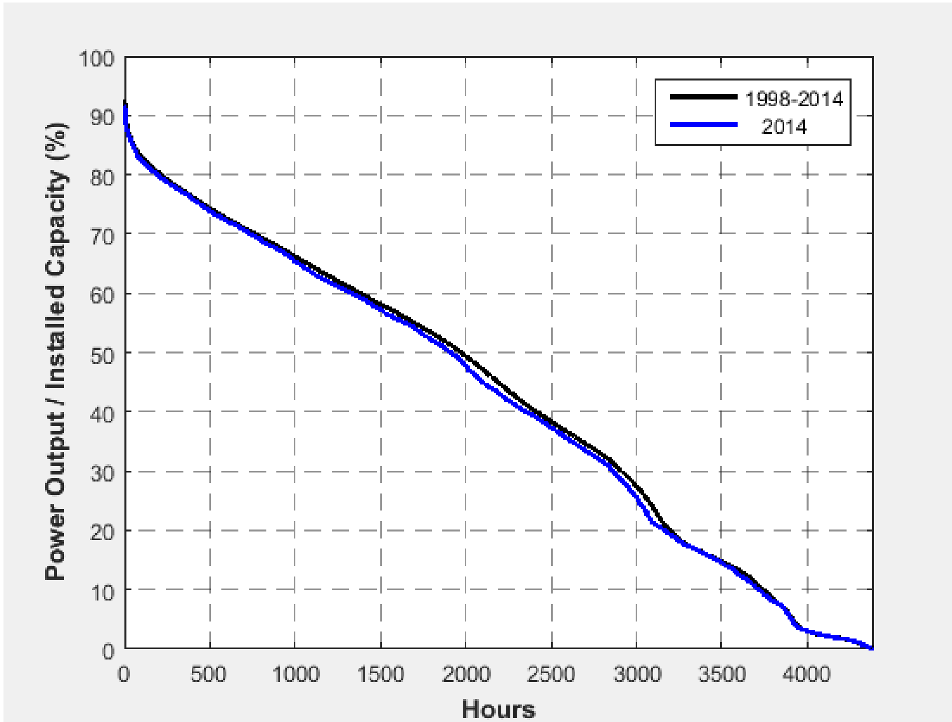

Figure F-41. Load Duration Curve—Power Output/Installed Capacity (all sites, fixed-tilt): Maui

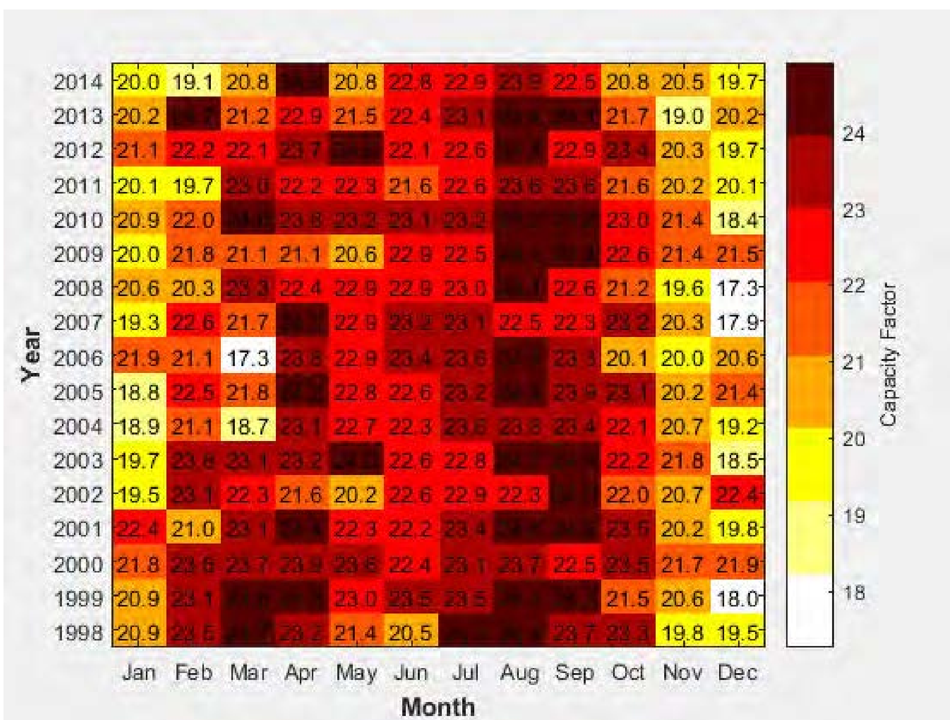

Figure F-42. Heat Map of Average Capacity Factor (selected sites, fixed tilt): Maui

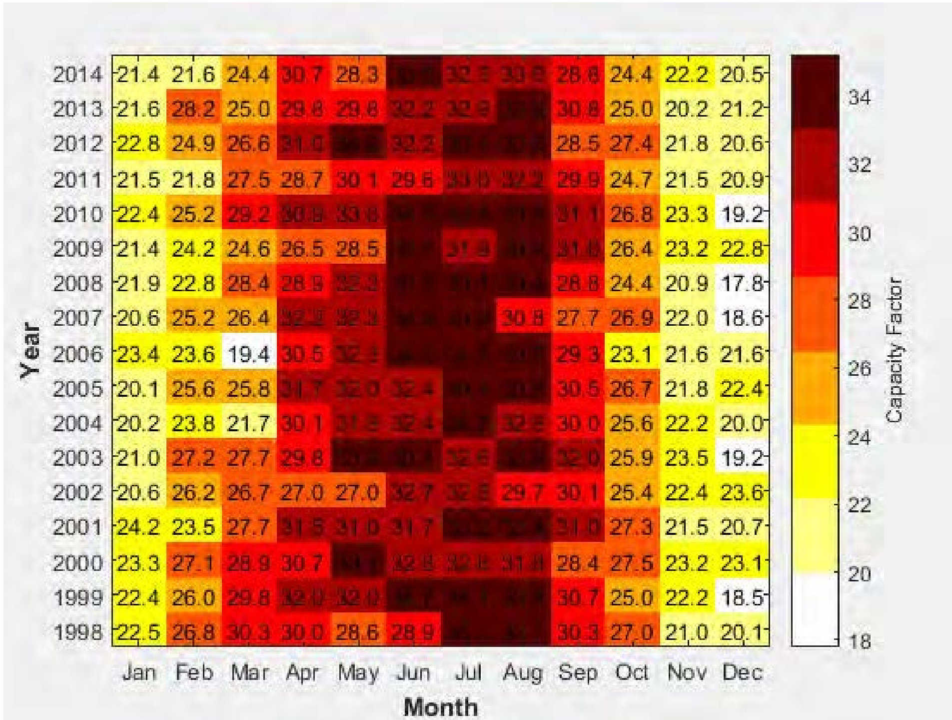

Figure F-43. Heat Map of Average Capacity Factor (selected sites, one-axis tracking): Maui

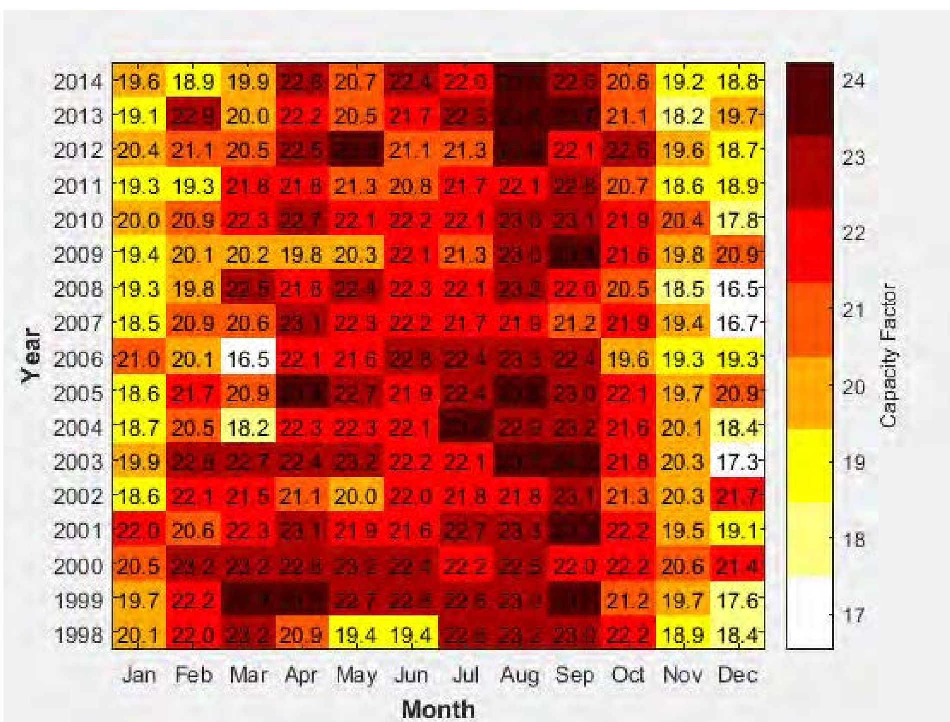

Figure F-44. Heat Map of Average Capacity Factor (all sites, fixed tilt): Maui

3.3 O'ahu

Year	All sites				Selected sites			
	1-axis tracking		Fixed tilt (20°)		1-axis tracking		Fixed tilt (20°)	
	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5	DC/AC = 1.2	DC/AC = 1.5
1998	0.233	0.286	0.190	0.236	0.233	0.286	0.190	0.236
1999	0.234	0.286	0.191	0.236	0.234	0.286	0.191	0.236
2000	0.246	0.301	0.200	0.247	0.246	0.301	0.200	0.247
2001	0.241	0.296	0.197	0.244	0.241	0.296	0.197	0.244
2002	0.242	0.298	0.199	0.247	0.242	0.298	0.199	0.247
2003	0.246	0.302	0.199	0.247	0.246	0.302	0.199	0.247
2004	0.242	0.297	0.196	0.243	0.242	0.297	0.196	0.243
2005	0.250	0.306	0.202	0.251	0.250	0.306	0.202	0.251
2006	0.237	0.290	0.193	0.239	0.237	0.290	0.193	0.239
2007	0.252	0.309	0.203	0.252	0.252	0.309	0.203	0.252
2008	0.244	0.299	0.197	0.245	0.244	0.299	0.197	0.245
2009	0.251	0.308	0.204	0.254	0.251	0.308	0.204	0.254
2010	0.246	0.301	0.200	0.247	0.246	0.301	0.200	0.247
2011	0.245	0.301	0.201	0.249	0.245	0.301	0.201	0.249
2012	0.240	0.294	0.195	0.242	0.240	0.294	0.195	0.242
2013	0.242	0.297	0.197	0.243	0.242	0.297	0.197	0.243
2014	0.245	0.300	0.198	0.246	0.245	0.300	0.198	0.246
Average (1998-2014)	0.243	0.298	0.198	0.245	0.243	0.298	0.198	0.245

Table F-12. Capacity Factor for Each Scenario and Each Year: O'ahu

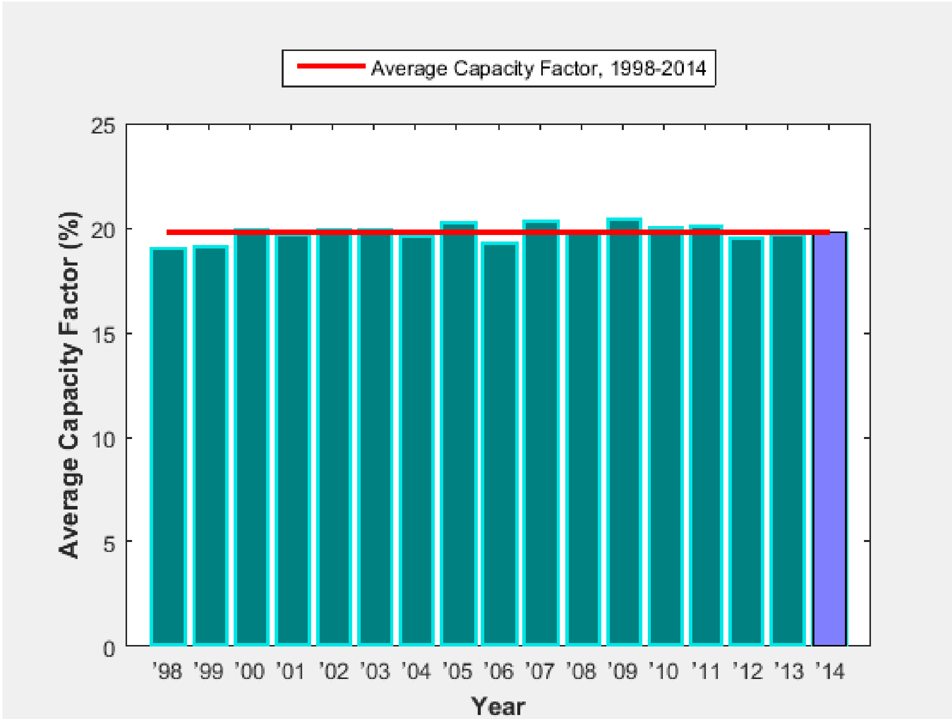

Figure F-45. Average Capacity Factor (selected sites, fixed tilt): O'ahu

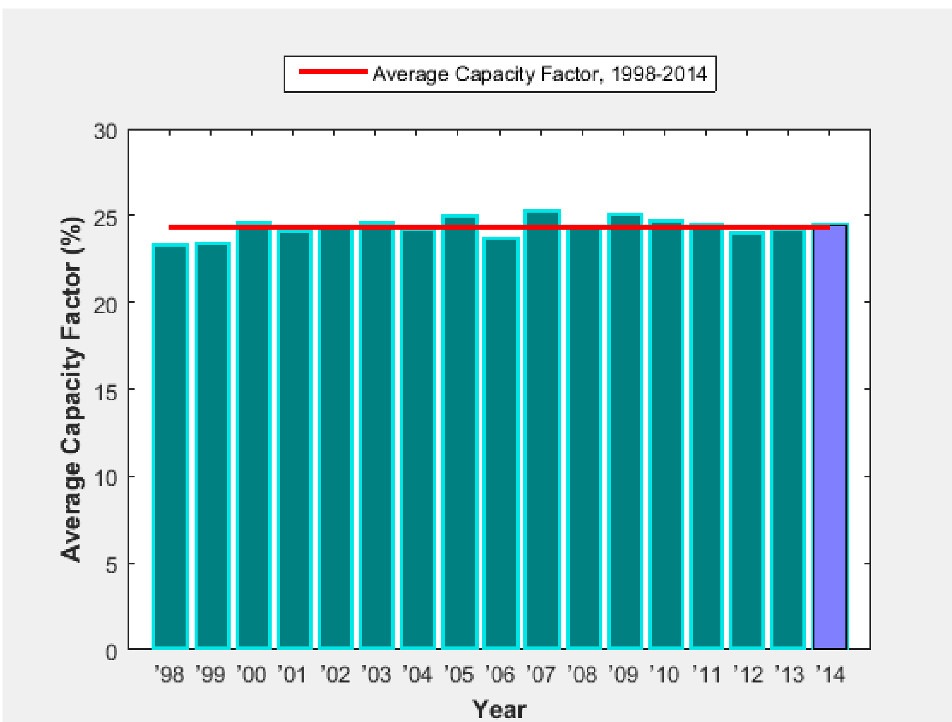

Figure F-46. Average Capacity Factor (selected sites, one-axis tracking): O'ahu

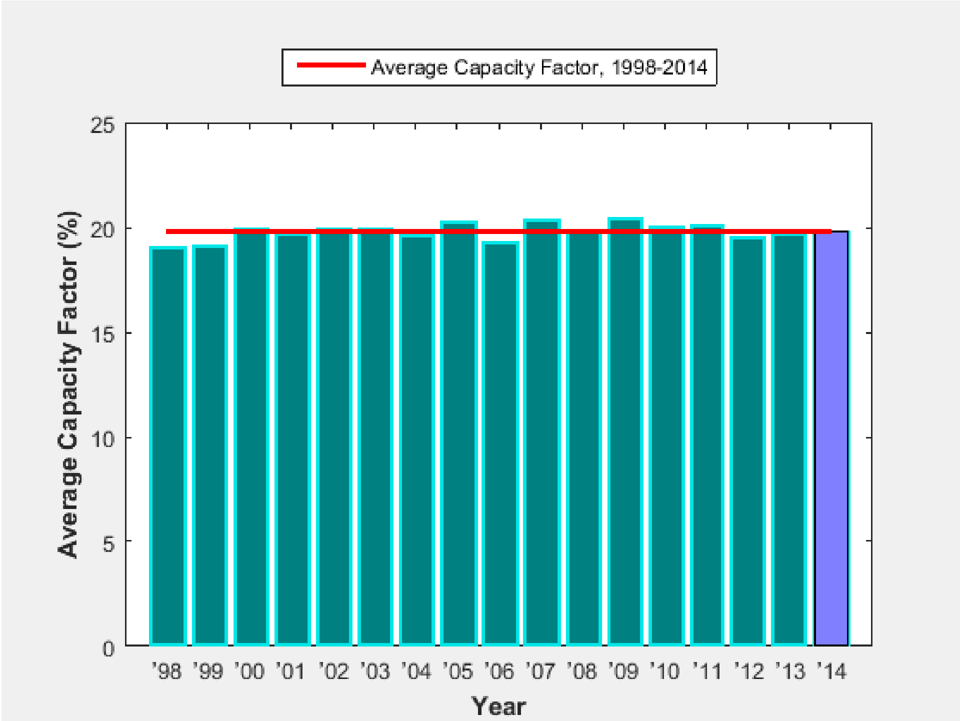

Figure F-47. Average Capacity Factor (all sites, fixed tilt): O'ahu

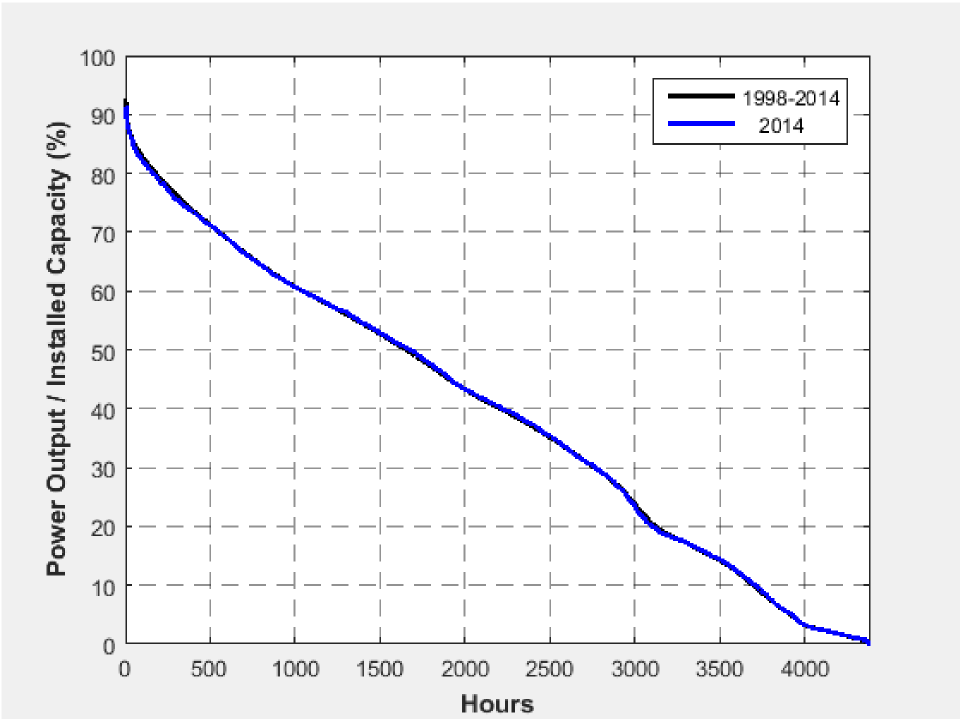

Figure F-48. Load Duration Curve—Power Output/Installed Capacity (selected sites, fixed-tilt): O'ahu

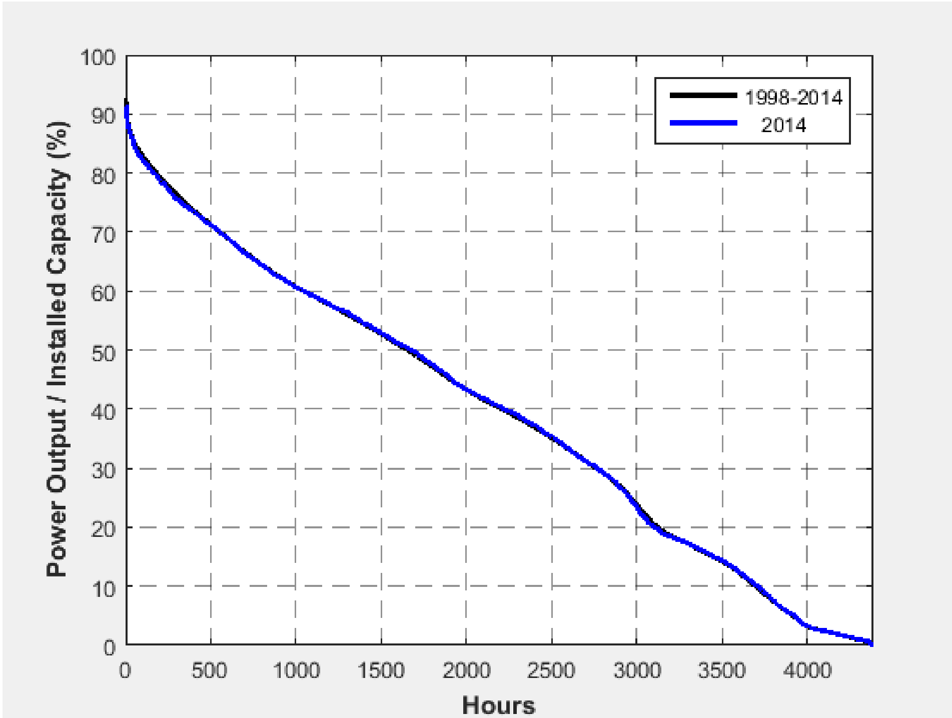

Figure F-49. Load Duration Curve—Power Output/Installed Capacity (all sites, fixed-tilt): O‘ahu

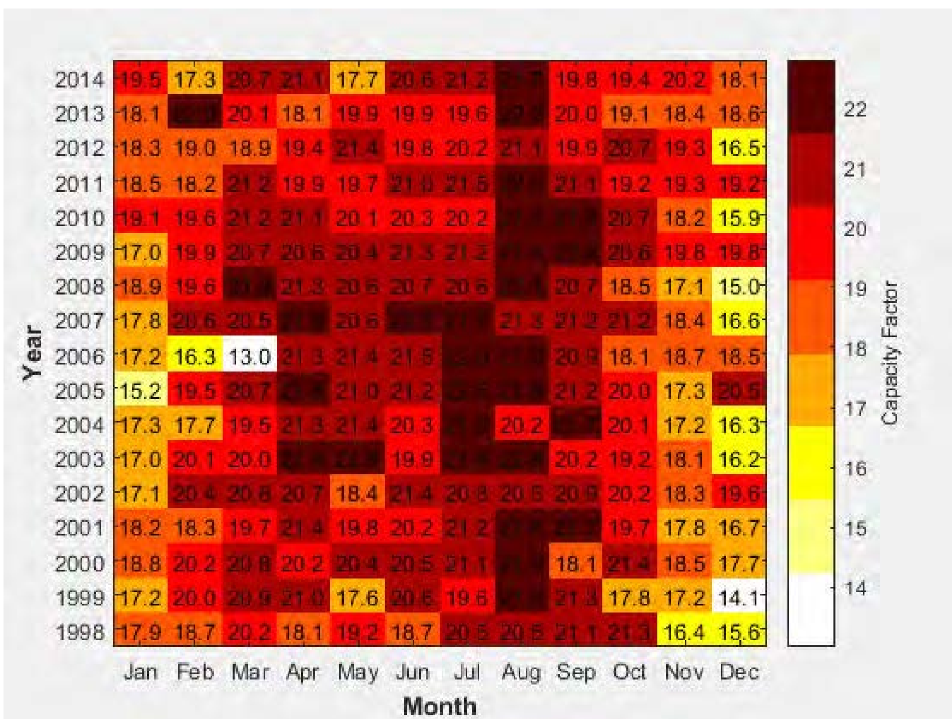

Figure F-50. Heat Map of Average Capacity Factor (selected sites, fixed tilt): O‘ahu

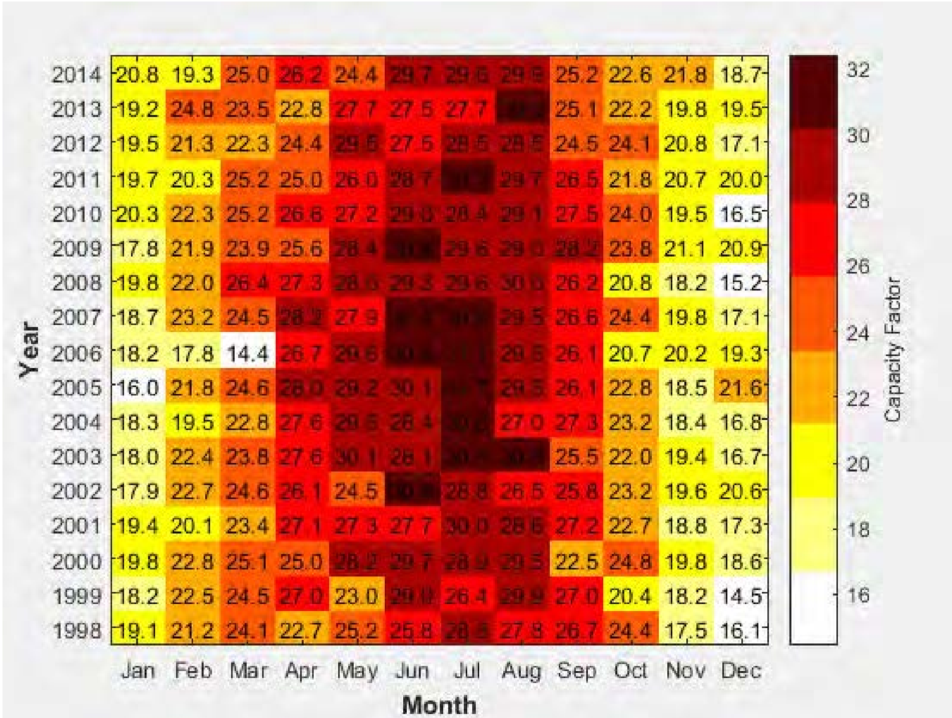

Figure F-51. Heat Map of Average Capacity Factor (selected sites, one-axis tracking): O‘ahu

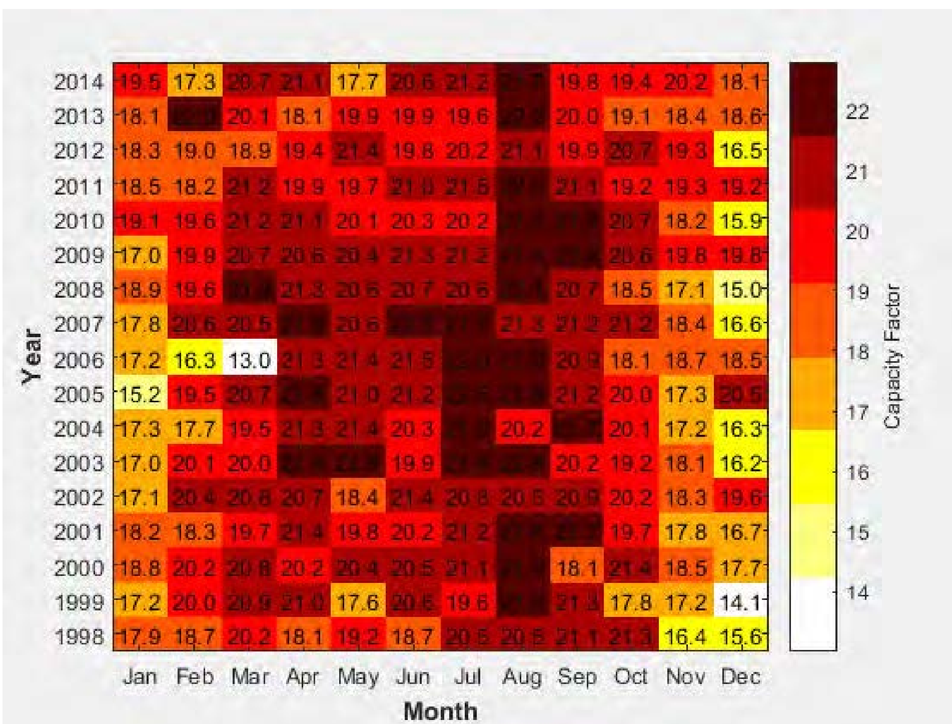

Figure F-52. Heat Map of Average Capacity Factor (all sites, fixed tilt): O‘ahu

References

[1] National Solar Radiation Database (NSRDB), https://nsrdb.nrel.gov

[2] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Anderberg, M.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Product for Use in NREL's National Solar Radiation Database: Preprint." 6 pp. NREL/CP-5D00-62776.

[3] Sengupta, M.; Habte, A.; Gotseff, P.; Weekley, A.; Lopez, A.; Molling, C.; Heidinger, A. (2014). "Physics-Based GOES Satellite Product for Use in NREL's National Solar Radiation Database: Preprint." 9 pp.; NREL/CP-5D00-62237

[4] System Advisor Model, SAM 2014.1.14: General Description, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-61019.

[5] PVWatts Version 5 Manual, National Renewable Energy Laboratory, September 4, 2014.

[6] Land-Use Requirements for Solar Power Plants in the United States, National Renewable Energy Laboratory, Technical Report No. NREL/TP-6A20-56290, June 2013.

[7] 2014 Cost of Wind Energy Review, National Renewable Energy Laboratory, October 2015. http://www.nrel.gov/docs/fy16osti/64281.pdf

[8] AWS Truepower, LLC, NREL REEDS LICENSED DATASETS AND USER'S GUIDE, November 5, 2014.

ELECTRICITY GENERATION CAPITAL, FIXED, AND VARIABLE O&M COSTS

NREL independently reviewed the 2016 updated PSIP resource assumptions (described in Appendix J: Modeling Assumptions Data), including their capital cost, and their fixed and variable operating and maintenance (O&M) costs. NREL also reviewed onshore wind, offshore wind, grid-scale PV, residential PV (DG-PV), concentrated solar power (CSP), biomass steam, geothermal, combined-cycle combustion turbines, and simple-cycle combustion turbines.

NREL compared our resource assumptions to their Annual Technology Baseline (ATB) database and resource assumptions from Lazard, an investment bank active in the power industry. The ATB database provides forward curves of these costs, while the Lazard data is only for a single point in time.

In general, the NREL findings support our resource assumptions; any differences are explained throughout the report.

Electricity Generation Capital, Fixed and Variable O&M Costs

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Report prepared by the National Renewable Energy Laboratory and submitted to the Hawaiian Electric Companies via email on 2/12/2016.

I. Introduction

The Hawaiian Electric Companies (Hawaiian Electric, Maui Electric, and Hawai'i Electric Light) submitted Power Supply Improvement Plans (PSIPs) in 2014 to help inform pending and future resource acquisition and system operation decisions. The Public Utilities Commission (Commission) reviewed the PSIPs and made recommendations to improve these plans. The Commission recommended that the Hawaiian Electric Companies (hereafter, the Companies) update and improve their technology cost and performance assumptions. In response, the Companies have done so for their 2016 PSIP. The Companies have contracted the National Renewable Energy Laboratory (NREL) to provide input on these assumptions used in its analysis of future electricity supply options.

In this report, we compare the Companies' 2014 and 2016 PSIP technology cost assumptions to those used in the NREL Annual Technology Baseline (ATB); we also compare the cost multipliers for converting continental U.S. technology costs to the Hawaiian system. The technology cost and performance assumptions within the Companies' 2014 PSIPs have been updated to reflect values more in line with those that we have observed in the ATB and other literature. In general, the Companies' assumptions for their draft 2016 PSIP are now much more in line with ATB assumptions. For utility-scale photovoltaics (PV), concentrated solar power (CSP), and land-based and onshore wind, the Companies assumed capital costs for the 2016 PSIP match well with those in the ATB, with differences mostly due to comparing different MW sizes of each technology. The most significant differences between the Companies' 2016 PSIP assumptions and NREL's assumptions for these four technology types lie in the operations and maintenance (O&M) costs. For thermal generation technologies (geothermal, biomass steam, combined cycle turbine, and simple cycle combustion turbine) the most significant differences reside in the O&M costs for geothermal and both capital and O&M costs for biomass steam.

II. Overview of the Cost Resources

This report reviews the capital costs, fixed O&M costs, and variable O&M costs for Hawai‘i from their 2014 and draft 2016 PSIP for a range of technologies. Capital costs reflect an overnight cost of building a power plant. The costs include only the plant envelope, and therefore do not include costs such as potential distribution-level upgrades or spur-line costs. Technology cost assumptions for the 2014 PSIPs were created from a cost report created by Black & Veatch in February 2012 for NREL using 2009 data (Black & Veatch, 2012). In line with Commission’s request to use more recent data, the Companies’ 2016 PSIP has been developed using cost assumption data from, but not limited to, NREL’s ATB, the Energy Information Administration (EIA), Lazard, the Electric Power Research Institute (EPRI), and customized cost assumptions developed by NextEra. Relative to the 2014 PSIPs cost assumptions, the 2016 PSIP renewable energy cost assumptions are generally lower. This report uses two up-to-date cost data sources to compare to the Companies’ data, namely the NREL ATB and Lazard-v9.0, which we describe below (National Renewable Energy Laboratory, 2015; Lazard, 2015).

1. ATB – Costs were reported in 2013$ and have been converted to nominal dollars to match the Companies’ data by using a constant 1.8% annual inflation rate. The ATB contains a range of cost assumptions for technologies coming online each year from 2014 through 2050. The range and mid-case for each technology was reported for 2016 to represent current costs, while projections for the same future years the Companies reported were also reported. Each mid-case observation reflects NREL’s best cost estimate of a given technology in a given year.[1]

2. Lazard-v9.0 – Costs were reported in 2015$ and have been converted to nominal dollars by using a constant 1.8% annual inflation rate. For each technology, Lazard provides a range for capital costs and fixed and variable O&M. We assume that Lazard costs are for plants that would begin construction in 2015. Unlike the ATB, Lazard does not provide cost projections for future years.

In addition to current cost estimates for 2016, the Companies’ PSIP report cost projections through 2045. The ATB includes projections over this range, but the estimates in the latter years are subject to considerable uncertainty.

The ATB and Lazard-v9.0 data reported here have been adjusted to represent capital costs in Hawai‘i (the Companies’ PSIP cost data is only for Hawai‘i). The cost multipliers for NREL’s data were taken from the appendix of the U.S. EIA report “Updated Capital Cost Estimates for

[1] ATB Disclaimer: It is recognized that disclosure of these Data is provided under the following conditions and warnings: (1) these Data have been prepared for reference purposes only; (2) these Data consist of forecasts, estimates or assumptions made on a best-efforts basis, based upon present expectations; and (3) these Data were prepared with existing information and are subject to change without notice.

Utility Scale Electricity Generating Plants," which was prepared for EIA by the Science Applications International Corporation (SAIC) (Science Applications International Corporation, 2013). The technology-specific multipliers in the report represent adjustments for economic conditions in Honolulu, Hawai'i. These same values were used by the Companies in their 2014 PSIPs for their cost input assumptions and they are presented in Table F-13. These multipliers, which pertain to projects in Honolulu, have been applied to the raw data from the ATB and Lazard in order to create Hawai'i-specific values.

Cost Multiplier Comparison

Technology	EIA/SAIC
Land-based wind	30.1%
Off-shore wind	13.8%
CSP	36.7%
Utility PV	40.5%
Biomass steam	53.6%
Geothermal	27.2%
Hydropower	0.0%
Combined cycle	53.1%
Combustion turbine	51.5%

Table F-13. Cost Multipliers

III. Technology Cost Assumptions Comparison

This section presents the technology costs assumptions by technology. Table F-14 to Table F-22 summarize the values that were included in the Companies' 2014 PSIPs, the Companies' 2016 PSIP, Lazard-v9.0, and the NREL ATB.

Notes: the year column corresponds to the installation year of the facility. Values in the tables below shaded with darker backgrounds represent "not available in this year".

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$2,867.01			$66.78			$0.00		
2020	$3,134.50			$73.01			$0.00		
2025	$3,426.94			$79.82			$0.00		
2030	$3,746.67			$87.27			$0.00		
2016 PSIPs - Oahu									
	30MW	200MW + Cable	400MW + Cable	30MW	200MW + Cable	400MW + Cable	30MW	200MW + Cable	400MW + Cable
2016	$2,465.00	N/A	N/A	$27.40	$27.40	$27.40	-	-	-
2020	$2,480.00	$5,097.00	$4,572.00	$29.43	$29.43	$29.43	-	-	-
2025	$2,722.00	$5,664.00	$5,085.00	$32.17	$32.17	$32.17	-	-	-
2030	$2,867.00	$6,154.00	$5,514.00	$35.17	$35.17	$35.17	-	-	-
2035	$3,010.00	$6,688.00	$5,981.00	$38.46	$38.46	$38.46	-	-	-
2040	$3,171.00	$7,270.00	$6,490.00	$42.04	$42.04	$42.04	-	-	-
2045	$3,333.00	$7,907.00	$7,046.00	$45.97	$45.97	$45.97	-	-	-
2016 PSIPs - Maui & Hawaii									
	10MW	20MW	30MW	10MW	20MW	30MW	10MW	20MW	30MW
2016	$4,171.00	$2,968.00	$2,465.00	$65.07	$41.61	$33.79	-	-	-
2020	$4,198.00	$2,987.00	$2,480.00	$69.88	$44.69	$36.29	-	-	-
2025	$4,606.00	$3,277.00	$2,722.00	$76.40	$48.86	$39.68	-	-	-
2030	$4,853.00	$3,453.00	$2,867.00	$83.53	$53.42	$43.38	-	-	-
2035	$5,093.00	$3,624.00	$3,010.00	$91.32	$58.40	$47.42	-	-	-
2040	$5,367.00	$3,819.00	$3,171.00	$99.85	$63.85	$51.85	-	-	-
2045	$5,640.00	$4,013.00	$3,333.00	$109.16	$69.80	$56.69	-	-	-
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,658.28		$2,255.27	$35.69		$40.79	$0.00		$0.00
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$2,021.73	$2,348.39	$2,412.90	$51.69	$52.75	$53.80	$0.00	$0.00	$0.00
2020	$2,045.98	$2,467.56	$2,591.38	$53.25	$55.52	$57.78	$0.00	$0.00	$0.00
2025	$2,124.06	$2,647.82	$2,833.15	$55.74	$59.46	$63.17	$0.00	$0.00	$0.00
2030	$2,257.04	$2,871.95	$3,097.48	$58.23	$63.65	$69.07	$0.00	$0.00	$0.00
2035	$2,442.57	$3,130.27	$3,386.47	$60.71	$69.59	$75.51	$0.00	$0.00	$0.00
2040	$2,670.46	$3,422.32	$3,702.42	$64.75	$74.46	$82.56	$0.00	$0.00	$0.00
2045	$2,919.61	$3,741.62	$4,047.86	$69.02	$81.41	$90.26	$0.00	$0.00	$0.00

Table F-14. Wind, Onshore

The cost estimates for land-based wind are presented in Table F-14. The capital costs for wind with a cable running from Maui to O'ahu (provided by the Companies in their 2016 PSIP) are much larger than those for non-cable projects according to all three data sources. the Companies' 2016 PSIP assumes the technology to be available from 2020 onward; for that year and beyond the 30 MW figures are between the low- and high-cases provided by the ATB. In contrast, the Companies' 2016 PSIP's capital cost estimates for smaller wind projects on Maui and Hawai'i Island (10 MW and 20 MW) are generally above the ATB high-case. For 20 MW projects, the difference between the Companies' costs and the ATB high case is relatively small, particularly in the later years. For 10 MW projects, the same difference is quite large.

The assumptions for the 2016 PSIP shows a reduction in O&M costs compared to the 2014 PSIPs for the 30 MW case and are generally close to or below the bounds provided by Lazard-v9.0. They are also significantly below the ATB low-case in all years for projects larger than 10 MW.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	Not Commercial			$0.00			$0.00		
2020	$5,815.90			$158.19			$0.00		
2025	$6,191.99			$172.94			$0.00		
2030	$6,604.17			$189.08			$0.00		
2016 PSIPs - Oahu									
	Floating Platform, 400MW			Floating Platform, 400MW			Floating Platform, 400MW		
2016	$5,062.00			$96.71			-		
2020	$4,500.00			$103.86			-		
2025	$4,013.00			$113.55			-		
2030	$4,067.00			$124.15			-		
2035	$4,202.00			$135.73			-		
2040	$4,403.00			$148.39			-		
2045	$4,617.00			$162.24			-		
2016 PSIPs - Maui & Hawaii									
	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2016	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2020	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2025	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2030	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2035	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2040	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2045	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$3,597.29	0	$6,382.29	$61.18	0	$101.97	$13.26	0	$18.35
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$5,622.24	$6,738.77	$8,562.43	$127.65	$136.09	$170.91	$0.00	$0.00	$0.00
2020	$5,300.59	$6,442.97	$8,495.64	$125.76	$130.30	$168.82	$0.00	$0.00	$0.00
2025	$4,915.50	$6,163.05	$8,622.91	$128.83	$130.07	$180.85	$0.00	$0.00	$0.00
2030	$4,973.40	$6,548.49	$9,427.42	$134.07	$138.14	$197.73	$0.00	$0.00	$0.00
2035	$5,218.37	$7,063.41	$10,306.99	$143.62	$149.55	$216.17	$0.00	$0.00	$0.00
2040	$5,465.75	$7,615.58	$11,268.62	$153.78	$161.88	$236.34	$0.00	$0.00	$0.00
2045	$5,740.05	$8,195.19	$12,319.97	$166.36	$176.98	$258.39	$0.00	$0.00	$0.00

Table F-15. Wind, Offshore

The cost estimates for offshore wind are presented in Table F-15. Note that there are no values for Maui and Hawai'i Island within the 2016 PSIPs because the Companies believe that the onshore wind resource potential for each of these islands exceeds the total maximum electrical demand for each of these islands, and therefore the more expensive offshore wind option would never be utilized for Maui or Hawai'i Island.

The values from the ATB represent fixed platform turbines, and the ranges reflect designs for shallow and deep water. In comparison the values from the companies represent floating offshore wind turbines, which have several differences relative to the fixed-bottom wind turbine that comprise the vast majority (~99%) of global installations to date. Floating wind turbine technology is less mature than fixed-bottom technology; the first floating turbine was installed in 2009 and four additional machines have been installed in the subsequent years. Because these projects are single turbine, proof-of-concept installations, they historically have been more expensive than fixed-bottom projects ($/kW basis). These projects are not able to achieve economies of scale and have elevated budgets for research and development. Floating technologies are, however, becoming increasingly mature and the first commercial applications are expected to occur by 2020 (Smith et al. 2015).

The economics of floating technologies are different from fixed-bottom technologies. Some elements, such as electric infrastructure, will be more expensive because cables must be able to withstand dynamic loading within the water column, whereas cables for fixed turbines can be laid out directly on the seabed. Other elements, such as installation and O&M costs, will be considerably lower because the entire turbine-substructure unit can be assembled in port and towed to the project site. The tow-out method reduces cost and risk by eliminating the need to conduct lifting operations in the offshore environment. Further, unlike fixed substructures, the weight of floating platforms is relatively insensitive to turbine size. As a result, the economics improve markedly for projects that use industry-leading 8+ MW wind turbines. While there is considerable uncertainty about the future cost of floating technology given its pre-commercial status, it is reasonable to expect that floating projects will be more competitive than fixed-bottom technology in deep water. Further, floating offshore wind in Deep Water could become more competitive than fixed-bottom offshore wind in Shallow Water by the mid- to late-2020s (Musial and Smith 2015).

Preliminary analysis conducted by NREL and the U.S. Department of Energy and presented at the 2015 National Offshore Wind Strategy Meeting held in Washington, DC on December 10th, suggests that a reference floating offshore wind facility installed in 2020 is expected to have an installed capital cost of approximately $4,500/kW, fixed O&M costs of approximately $80/kW-year, and no variable O&M costs. This capital cost estimate is reflected in the 2016 PSIP values. The 2016 PSIP values for capital cost are consistently lower than ATB's fixed turbine range. Moreover, the fixed O&M estimates for the 2016 PSIPs are also much lower than the ATB range.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$3,987.52			$53.42			$0.00		
2020	$4,120.21			$54.76			$0.00		
2025	$4,261.63			$57.20			$0.00		
2030	$4,454.88			$59.63			$0.00		
2016 PSIPs - Oahu									
	20MW			20MW			20MW		
2016	$2,793.00			$22.97			-		
2020	$2,432.00			$24.67			-		
2025	$2,284.00			$26.97			-		
2030	$2,232.00			$29.49			-		
2035	$2,203.00			$32.24			-		
2040	$2,174.00			$35.25			-		
2045	$2,146.00			$38.53			-		
2016 PSIPs - Maui & Hawaii									
	5MW	10MW	20MW	5MW	10MW	20MW	5MW	10MW	20MW
2016	$3,262.00	$2,849.00	$2,574.00	$29.87	$28.20	$24.77	-	-	-
2020	$2,841.00	$2,481.00	$2,241.00	$32.08	$30.29	$26.60	-	-	-
2025	$2,669.00	$2,331.00	$2,105.00	$35.07	$33.11	$29.08	-	-	-
2030	$2,608.00	$2,278.00	$2,057.00	$38.34	$36.20	$31.80	-	-	-
2035	$2,574.00	$2,248.00	$2,031.00	$41.92	$39.58	$34.76	-	-	-
2040	$2,540.00	$2,218.00	$2,004.00	$45.83	$43.27	$38.01	-	-	-
2045	$2,507.00	$2,189.00	$1,978.00	$50.11	$47.31	$41.55	-	-	-
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$2,292.28	0	$2,149.01	$13.26	0	$10.20	$0.00	0	$0.00
ATB (100MW Single Axis Tracking)									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$2,776.69	$3,066.91	$3,293.55	$17.41	$17.41	$17.41	$0.00	$0.00	$0.00
2020	$1,871.89	$2,808.72	$3,537.16	$9.97	$9.97	$9.97	$0.00	$0.00	$0.00
2025	$2,046.54	$2,559.61	$3,867.17	$10.90	$10.90	$10.90	$0.00	$0.00	$0.00
2030	$2,237.48	$2,237.48	$4,227.98	$11.92	$11.92	$11.92	$0.00	$0.00	$0.00
2035	$2,446.23	$2,446.23	$4,622.44	$13.03	$13.03	$13.03	$0.00	$0.00	$0.00
2040	$2,674.46	$2,674.46	$5,053.71	$14.25	$14.25	$14.25	$0.00	$0.00	$0.00
2045	$2,923.99	$2,923.99	$5,525.22	$15.57	$15.57	$15.57	$0.00	$0.00	$0.00

Table F-16. Grid-Scale Photovoltaics

The cost estimates for utility-scale PV are presented in Table F-16[2]. The low and high values from Lazard-v9.0 correspond to different types of solar technology. The lower capital cost is associated with fixed-tilt systems, which have a lower capacity factor. The higher capital cost is associated with 1-axis tracking systems, which have a higher capacity factor. Thus, the lower capital cost system actually has a higher levelized cost of electricity (LCOE) than the higher capital cost system. The ATB values reflect cost estimates for single axis tracking solar at 100 MW in size; over 154 GW of available capacity has been summarized into this data.

The capital and O&M costs decreased significantly from the 2014 PSIPs to the 2016 PSIP. Whereas all costs within the 2014 PSIPs are higher than the ranges in Lazard or ATB, the costs from the 2016 PSIP are much more comparable. The 2016 PSIP shows the utility scale PV coming online in 2020 when the capital costs are slightly higher than the range of costs given by Lazard-v9.0 (except for the 20 MW case in Maui and Hawaiʻi Island) and within the range from the ATB. The future capital cost projections from the 2016 PSIPs are within the ATB range until 2030, at which point they drop below the ATB low-case. This occurs because the 2016 PSIP assumed values continue to decline while the ATB capital costs begin to flat-line in real dollars (that is, they increase nominally). The fixed O&M costs from the 2016 PSIPs are higher than those provided by Lazard-v9.0 and the ATB, both currently and in future years. This is at least partly expected given the ATB values are for a 100 MW solar farm as opposed to the Companies, who considered 5 MW, 10 MW, and 20 MW projects.

Year	Hawaii Specific Nominal Capital Costs ($/kW)	Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)	Hawaii Specific Nominal Variable O&M Costs ($/kW)
2014 PSIPs - HECO, MECO, HELCO			
2015	$4,830.33	$53.42	$0.00
2020	$4,563.07	$54.76	$0.00
2025	$4,603.00	$57.20	$0.00
2030	$4,785.19	$59.63	$0.00
2016 PSIPs - Oahu			
2016	$3,945.00	n/a	n/a
2020	$3,360.00	n/a	n/a
2025	$3,068.00	n/a	n/a
2030	$2,933.00	n/a	n/a
2035	$2,894.00	n/a	n/a
2040	$2,856.00	n/a	n/a
2045	$2,819.00	n/a	n/a
2016 PSIPs - Maui & Hawaii			
2016	$3,985.00	n/a	n/a
2020	$3,394.00	n/a	n/a
2025	$3,100.00	n/a	n/a
2030	$2,962.00	n/a	n/a
2035	$2,924.00	n/a	n/a
2040	$2,885.00	n/a	n/a
2045	$2,848.00	n/a	n/a

Table F-17. Residential Photovoltaics

The cost estimates for utility-scale PV are presented in Table F-17. There is no cost data for residential photovoltaics provided for the 2016 PSIP, or within ATB or Lazard-v9.0. However, as exhibited in the 2014 PSIP numbers, there is a substantial cost advantage to utility-scale PV over residential PV due to significant economies of scale.

Year	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW-year)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2016 PSIPs - Oahu									
	100MW Solar CSP + 10hrs storage			100MW Solar CSP + 10hrs storage			100MW Solar CSP + 10hrs storage		
2016	$12,304.00			$92.38			n/a		
2020	$9,848.00			$99.21			n/a		
2025	$7,694.00			$108.47			n/a		
2030	$7,309.00			$118.59			n/a		
2035	$7,508.00			$129.65			n/a		
2040	$8,209.00			$141.75			n/a		
2045	$8,975.00			$154.98			n/a		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$12,196.86		$12,545.34	$10.20		$13.26	$0.00		$0.00
ATB									
	Low	Mid	High	Low	Mid	High	Low	Mid	High
2016	$6,806.97	$11,271.88	$14,219.65	$68.57	$68.57	$68.57	$3.16	$3.16	$3.16
2020	$4,775.03	$7,590.80	$9,567.11	$57.78	$57.78	$57.78	$3.40	$3.40	$3.40
2025	$5,220.54	$7,289.79	$10,459.71	$63.17	$63.17	$63.17	$3.72	$3.72	$3.72
2030	$5,707.61	$6,868.39	$11,435.58	$69.07	$69.07	$69.07	$4.06	$4.06	$4.06
2035	$6,240.12	$7,509.20	$12,502.51	$75.51	$75.51	$75.51	$4.44	$4.44	$4.44
2040	$6,822.32	$8,209.80	$13,668.98	$82.56	$82.56	$82.56	$4.86	$4.86	$4.86
2045	$7,458.83	$8,975.76	$14,944.28	$90.26	$90.26	$90.26	$5.31	$5.31	$5.31

Table F-18. Concentrated Solar Power (CSP)

The cost estimates for utility-scale PV are presented in Table F-18. Note that there are no estimates for CSP for either the 2014 PSIPs or Maui and Hawai‘i Island in the 2016 PSIP. The data for the 2016 PSIP assumes 10 hours of Thermal Energy Storage (TES), while the data from the ATB includes cases of 6 hours and 12 hours of TES. The 2016 PSIP current capital cost estimates for O‘ahu are within the bounds provided by Lazard-v9.0 and the ATB. In future years, the 2016 PSIP costs are generally within the bounds provided by the ATB (the lone exception occurs in 2020). However, the Companies’ fixed O&M estimates are much higher than the Lazard-v9.0 values, and higher than the values from the ATB high-case. The variable O&M values from the ATB are non-zero due to the storage component of CSP, whereas the 2016 PSIP and Lazard-v9.0 values assume no variable O&M costs.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$6,547.52			$105.73			$16.69		
2020	$7,158.39			$115.60			$18.25		
2025	$7,826.26			$126.38			$19.96		
2030	$8,556.44			$138.17			$21.82		
2016 PSIPs - Oahu									
	20MW			20MW			20MW		
2016	$5,251.00			$79.05			$12.98		
2020	$5,299.00			$84.90			$13.94		
2025	$5,692.00			$92.82			$15.24		
2030	$6,107.00			$101.48			$16.66		
2035	$6,546.00			$110.95			$18.22		
2040	$6,973.00			$121.30			$19.92		
2045	$7,624.00			$132.61			$21.78		
2016 PSIPs - Maui & Hawaii									
	20MW			20MW			20MW		
2016	$5,251.00			$79.05			$13.00		
2020	$5,299.00			$84.90			$13.96		
2025	$5,692.00			$92.82			$15.26		
2030	$6,107.00			$101.48			$16.69		
2035	$6,546.00			$110.95			$18.25		
2040	$6,973.00			$121.30			$19.95		
2045	$7,624.00			$132.61			$21.81		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$4,072.27	0	$5,481.90	$96.87	0	$96.87	$15.30	0	$15.30
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$6,295.43	$6,295.43	$6,295.43	$112.88	$112.88	$112.88	$5.27	$5.27	$5.27
2020	$6,353.86	$6,353.86	$6,353.86	$121.23	$121.23	$121.23	$5.67	$5.67	$5.67
2025	$6,824.89	$6,824.89	$6,824.89	$132.54	$132.54	$132.54	$6.19	$6.19	$6.19
2030	$7,322.28	$7,322.28	$7,322.28	$144.91	$144.91	$144.91	$6.77	$6.77	$6.77
2035	$7,848.51	$7,848.51	$7,848.51	$158.43	$158.43	$158.43	$7.40	$7.40	$7.40
2040	$8,361.96	$8,361.96	$8,361.96	$173.21	$173.21	$173.21	$8.09	$8.09	$8.09
2045	$9,142.12	$9,142.12	$9,142.12	$189.37	$189.37	$189.37	$8.85	$8.85	$8.85

Table F-19. Biomass Steam

The cost estimates for biomass steam are presented in Table F-19. The data from the 2016 PSIP represent a stand-alone biomass plant (50 MW net); both capital costs and fixed O&M costs are much lower compared to the 2014 PSIPs. The capital cost used in the 2016 PSIP for 2020 is within the range provided by Lazard-v9.0. Capital costs from the 2016 PSIP are also significantly lower than the single values from the ATB in both the current year and the future projections. Fixed O&M costs from the 2016 PSIP for 2020 are significantly below values from Lazard-v9.0, and for all years they are significantly below the ATB values. Variable O&M costs from the 2016 draft PSIP in 2020 are similar to values from Lazard-v9.0, while for all years they are higher than the ATB values.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
	Non-Dispatchable		Fully Dispatchable	Non-Dispatchable		Fully Dispatchable	Non-Dispatchable		Fully Dispatchable
2015	$8,409.31		$8,586.27	$40.07		$40.07	$34.50		$34.50
2020	$9,193.89		$9,387.36	$43.81		$43.81	$37.72		$37.72
2025	$10,051.66		$10,263.19	$47.89		$47.89	$41.24		$41.24
2030	$10,989.47		$11,220.73	$52.36		$52.36	$45.09		$45.09
2016 PSIPs - Oahu									
2016	n/a			n/a			n/a		
2020	n/a			n/a			n/a		
2025	n/a			n/a			n/a		
2030	n/a			n/a			n/a		
2035	n/a			n/a			n/a		
2040	n/a			n/a			n/a		
2045	n/a			n/a			n/a		
2016 PSIPs - Maui & Hawaii									
	20MW, Fuel Type Lava			20MW, Fuel Type Lava			20MW, Fuel Type Lava		
2016	$8,804.00			$158.11			$2.58		
2020	$9,456.00			$169.81			$2.77		
2025	$10,338.00			$185.65			$3.03		
2030	$11,302.00			$202.97			$3.31		
2035	$12,357.00			$221.91			$3.62		
2040	$13,510.00			$242.62			$3.96		
2045	$14,770.00			$265.25			$4.33		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$5,058.52	0	$7,263.51	$0.00	0	$0.00	$30.59	0	$40.79
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$8,040.86	$9,382.79	$14,382.83	$121.32	$121.32	$121.32	$0.00	$0.00	$0.00
2020	$8,635.62	$10,076.81	$15,446.69	$130.30	$130.30	$130.30	$0.00	$0.00	$0.00
2025	$9,441.31	$11,016.96	$16,887.84	$142.45	$142.45	$142.45	$0.00	$0.00	$0.00
2030	$10,322.17	$12,044.83	$18,463.46	$155.74	$155.74	$155.74	$0.00	$0.00	$0.00
2035	$11,285.22	$13,168.60	$20,186.08	$170.27	$170.27	$170.27	$0.00	$0.00	$0.00
2040	$12,338.12	$14,397.22	$22,069.42	$186.16	$186.16	$186.16	$0.00	$0.00	$0.00
2045	$13,489.25	$15,740.46	$24,128.47	$203.53	$203.53	$203.53	$0.00	$0.00	$0.00

Table F-20. Geothermal

The cost estimates for geothermal are presented in Table F-20. Note that the Companies only considered geothermal projects on Maui and Hawai‘i Island. The numbers from ATB are site-specific, which is why the capital cost ranges are large.

The 2016 PSIPs include slightly higher capital cost assumptions and much higher O&M costs compared to the values from the 2014 PSIPs. The capital cost values within the 2016 PSIPs are always within the ATB ranges (near the low-case) but much higher than values from Lazard-v9.0. The 2016 PSIP fixed O&M costs are significantly higher than the ATB estimates throughout the entire horizon.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)	Hawaii Specific Nominal Fixed O&M Costs ($/kW)	Hawaii Specific Nominal Variable O&M Costs ($/kW)
2014 PSIPs - HECO, MECO, HELCO			
2015	$1,097.69	$5.85	$33.28
2020	$1,200.10	$6.40	$36.38
2025	$1,312.07	$7.00	$39.78
2030	$1,434.49	$7.65	$43.49
2016 PSIPs - Oahu			
	100MW Gas / Oil	100MW Gas / Oil	100MW Gas / Oil
2016	$1,237.00	$9.01	$12.99
2020	$1,292.00	$9.68	$13.95
2025	$1,373.00	$10.58	$15.25
2030	$1,466.00	$11.57	$16.68
2035	$1,577.00	$12.65	$18.23
2040	$1,706.00	$13.83	$19.93
2045	$1,865.00	$15.12	$21.79

Year Installed	Capital Costs ($/kW)	Fixed O&M Costs ($/kW)		Variable O&M Costs ($/kW)	
2016 PSIPs - Maui & Hawaii					
	20.5MW Gas / Oil	20.5MW Gas / Oil Maui	20.5MW Gas / Oil Hawaii	20.5MW Gas / Oil Maui	20.5MW Gas / Oil Hawaii
2016	$3,586.00	$140.00	$140.00	$1.26	$1.75
2020	$3,747.00	$150.36	$150.36	$1.35	$1.88
2025	$3,981.00	$164.38	$164.38	$1.48	$2.05
2030	$4,251.00	$179.72	$179.72	$1.62	$2.25
2035	$4,571.00	$196.49	$196.49	$1.77	$2.46
2040	$4,947.00	$214.82	$214.82	$1.93	$2.69
2045	$5,408.00	$234.86	$234.86	$2.11	$2.94

Year Installed	Capital Costs ($/kW)			Fixed O&M Costs ($/kW)			Variable O&M Costs ($/kW)		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,235.87	0	$1,544.84	$5.10	0	$25.49	$4.79	0	$7.65
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$1,324.98	$1,324.98	$1,324.98	$7.38	$7.38	$7.38	$13.71	$13.71	$13.71
2020	$1,385.23	$1,385.23	$1,385.23	$7.93	$7.93	$7.93	$14.73	$14.73	$14.73
2025	$1,471.30	$1,471.30	$1,471.30	$8.67	$8.67	$8.67	$16.10	$16.10	$16.10
2030	$1,571.64	$1,571.64	$1,571.64	$9.48	$9.48	$9.48	$17.61	$17.61	$17.61
2035	$1,689.11	$1,689.11	$1,689.11	$10.36	$10.36	$10.36	$19.25	$19.25	$19.25
2040	$1,829.54	$1,829.54	$1,829.54	$11.33	$11.33	$11.33	$21.04	$21.04	$21.04
2045	$2,000.23	$2,000.23	$2,000.23	$12.39	$12.39	$12.39	$23.01	$23.01	$23.01

Table F-21. Combined Cycle Turbine

The cost estimates for combined cycle turbines are presented in Table F-21. Note that no cost estimates for the 2016 PSIP were included for Maui and Hawai‘i Island. The values for the 2016 PSIP represent either a single-unit 152 MW plant or a three-unit 383 MW plant, both without carbon capture and sequestration (CCS). The low and high values for the Lazard-v9.0 data correspond to different types of configurations of Combined Cycle Turbines. The current capital costs for the 2016 PSIP are within the bounds from Lazard-v9.0, while the fixed and variable O&M costs are higher. For the current year and all future projections, the 2016 PSIP capital and O&M costs are slightly higher than those from the ATB.

Year Installed	Hawaii Specific Nominal Capital Costs ($/kW)			Hawaii Specific Nominal Fixed O&M Costs ($/kW)			Hawaii Specific Nominal Variable O&M Costs ($/kW)		
2014 PSIPs - HECO, MECO, HELCO									
2015	$2,095.88			$7.02			$4.08		
2020	$2,291.43			$7.68			$4.47		
2025	$2,505.21			$8.39			$4.88		
2030	$2,738.95			$9.18			$5.34		
2016 PSIPs - Oahu									
	152MW (1 x 1)		383MW (3 x 1)	152MW (1 x 1)		383MW (3 x 1)	152MW (1 x 1)		383MW (3 x 1)
2016	$1,660.00		$1,758.00	$17.29		n/a	$4.49		n/a
2020	$1,742.00		$1,845.00	$18.57		n/a	$4.82		n/a
2025	$1,859.00		$1,969.00	$20.30		n/a	$5.27		n/a
2030	$1,991.00		$2,108.00	$22.20		n/a	$5.76		n/a
2035	$2,143.00		$2,270.00	$24.27		n/a	$6.30		n/a
2040	$2,318.00		$2,455.00	$26.53		n/a	$6.89		n/a
2045	$2,535.00		$2,684.00	$29.01		n/a	$7.53		n/a
2016 PSIPs - Maui & Hawaii									
2016	n/a			n/a			n/a		
2020	n/a			n/a			n/a		
2025	n/a			n/a			n/a		
2030	n/a			n/a			n/a		
2035	n/a			n/a			n/a		
2040	n/a			n/a			n/a		
2045	n/a			n/a			n/a		
Lazard-v9.0									
	Low		High	Low		High	Low		High
2015	$1,405.04	0	$1,873.39	$6.32	0	$5.61	$3.57	0	$2.04
ATB									
	Low	Mid-Point	High	Low	Mid-Point	High	Low	Mid-Point	High
2016	$1,578.02	$1,578.02	$1,578.02	$14.77	$14.77	$14.77	$3.16	$3.16	$3.16
2020	$1,654.85	$1,654.85	$1,654.85	$15.86	$15.86	$15.86	$3.40	$3.40	$3.40
2025	$1,767.52	$1,767.52	$1,767.52	$17.34	$17.34	$17.34	$3.72	$3.72	$3.72
2030	$1,890.96	$1,890.96	$1,890.96	$18.96	$18.96	$18.96	$4.06	$4.06	$4.06
2035	$2,037.91	$2,037.91	$2,037.91	$20.73	$20.73	$20.73	$4.44	$4.44	$4.44
2040	$2,203.27	$2,203.27	$2,203.27	$22.66	$22.66	$22.66	$4.86	$4.86	$4.86
2045	$2,408.83	$2,408.83	$2,408.83	$24.78	$24.78	$24.78	$5.31	$5.31	$5.31

Table F-22. Simple Cycle Combustion Turbine

The cost estimates for simple cycle combustion turbines are presented in Table F-22. The 2016 PSIPs have cost estimates for a 100 MW plant on O‘ahu and a 20.5 MW plant on Maui and Hawai‘i Island; the capital and fixed O&M cost estimates are much greater for the 20.5 MW plant versus the 100 MW plant. The 100 MW plant has slightly higher capital and fixed O&M costs compared to the 2014 PSIPs and much lower variable O&M costs. The current capital costs for the 100 MW plant in the 2016 PSIP are within the bounds from Lazard-v9.0. For both the current year and future projections, the capital costs for the 100 MW plant in the 2016 PSIP are slightly lower to those from the ATB, the fixed O&M costs are slightly higher and the variable O&M costs are slightly lower.

IV. Conclusion

In general, the Companies’ assumptions for their draft 2016 PSIP are now much more in line with ATB assumptions. The most significant differences reside in the O&M costs for geothermal and both capital and O&M costs for biomass steam.

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G. Energy Storage Systems

Energy storage systems are expected to play a fundamental role in achieving our 100% renewable energy goal. Energy storage systems provide the ability to time shift the output of variable renewable resources; in other words, absorbing and storing renewable energy when that generation exceeds customer demand, and releasing that energy later (typically several hours) when energy demand is high and renewable output is low. Energy storage systems can also provide important ancillary services to the system (for example, contingency reserves) and grid support where needed to ensure reliable service to customers.

Historically, pumped storage hydroelectric systems have been the only available energy storage technology for use in bulk power systems.[1] Battery energy storage systems (BESS) for utility applications are being currently offered commercially by a number of vendors. Market forecasts by various analysts project the capital cost of BESS, particularly lithium-ion batteries, to decline substantially over the next five to ten years. Other energy storage technologies (for example, flywheels) are emerging and can potentially compete with lithium-ion batteries in the near future. In the longer term, hydrogen energy storage might play a role at a bulk power level, but today exist only in small scale pilot projects.

Some electricity customers are beginning to install distributed energy storage systems (DESS) together with their rooftop solar PV installation. Integrating solar PV and electric vehicle charging is also emerging as a potential energy storage system that can manage and balance customer supply and demand, and potentially for the entire grid.

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[1] Compressed air energy storage (CAES) has also been in commercial operation for many years, but to date there have been only a very small number of projects built due to the specific geology required and relatively high capital cost.

The Companies anticipate including energy storage systems in our portfolio of resources required to achieve 100% renewable energy. Energy storage systems resources are expected to become more prevalent over time as costs decline and technology improves.

ENERGY STORAGE TECHNOLOGIES

Various sizes of energy storage systems are commercially available ranging from one to two kilowatts of output to hundreds of megawatts, and with output durations of as much as six hours (or longer as with some pumped storage hydroelectricity projects).

For our December 2016 PSIP, we considered these energy storage systems: flywheels, pumped storage hydroelectric energy storage, lithium-ion energy storage systems, distributed energy storage systems (DESS), and hydrogen energy storage.

Flywheels

Flywheels are rotating mechanical devices that store energy in the angular momentum of its rotating mass. A flywheel consists of a rotor (its rotating mass) attached to a motor (mounted on a very low friction bearing) and generator that spins at high speeds. To maintain the angular momentum of its rotating mass, a flywheel's motor acts like load and draws power from the grid, which enables the flywheel to absorb energy.

Flywheels provide inertia to a power system. During a grid event (such as a sudden loss of load), the inertia from the flywheel's motor drives its generator, creating replacement electricity that is injected back into the power system. The duration of the replacement electricity is relatively short (minutes at most). However, flywheels are useful for providing frequency response and can provide "ride-through" of contingency events (for example, the sudden loss of a large generator) that would otherwise result in significant frequency decay and possible loss of load. Typically the frequency response of a flywheel is faster than the response of a generator. Flywheels can provide the inertial response necessary to slow the rate of frequency decay, giving spinning reserve enough time to pick up load.

Flywheels have a minimum and maximum speed. The flywheel's actual speed indicates its "state of charge". The minimum speed represents a fully discharged state; the maximum speed represents a fully charged state.

While flywheels are expensive (high capital costs), they can charge and discharge hundreds of thousands of times over their useful life. Flywheel energy storage can be developed in two years or less (not including regulatory approvals and permitting lead-times). The round trip efficiency of a flywheel storage system is approximately 85%.

Flywheels have very little environmental impact. Modern metallurgy has produced flywheel technologies that are safe during operation. Flywheels can also be placed underground for additional safety.

The more than 400 flywheels currently placed in grid-scale situations have been operating for more than seven million hours.[2]

Beacon Power is the major flywheel manufacturer providing commercial grid-scale systems operating in the United States. Other flywheel manufacturers (such as Amber Kinetics) are working towards bringing their systems to market.

The rotor of a Beacon Power Smart Energy 25 flywheel spins between 8,000 rpm and 16,000 rpm. At 16,000 rpm, a single flywheel can deliver 30 kWh of extractable energy at a power level up to 265 kW for five minutes or as low as 170 kW for ten minutes (Figure G-1).

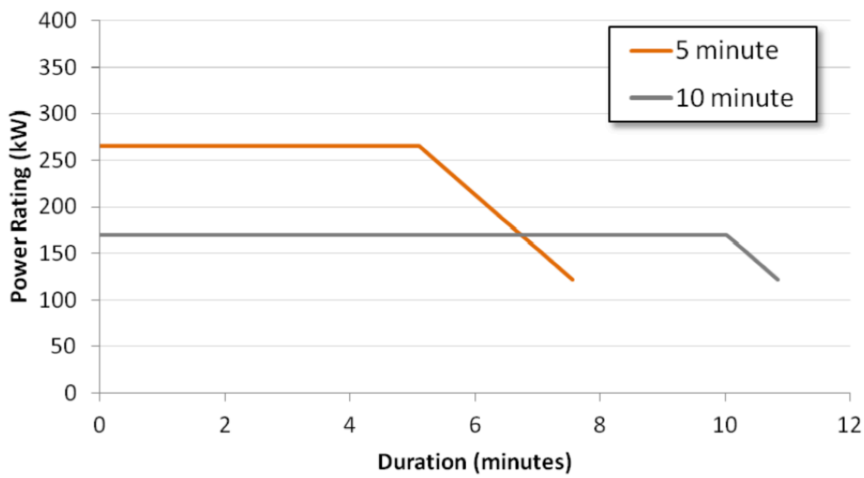

Figure G-1. Flywheel Extractable Energy Rates and Duration

The cyclic life capability of energy storage-based systems is of critical importance for performing frequency regulation. Beacon's flywheel is designed for a minimum 20-year life, with virtually no maintenance required for the mechanical portion of the flywheel system over its lifetime.

Beacon's experience to date in ISO New England involves 6,000 or more effective full charge and discharge cycles per year. The flywheel system is capable of over 175,000 full charge and discharge cycles at a constant full power charge and discharge rate, with no degradation in energy storage capacity over time.

2 http://beaconpower.com/operating-plants/.

A flywheel's mechanical efficiency for frequency response is over 97 percent; total system round-trip charge and discharge efficiency is 85 percent. Figure G-2 depicts a flywheel's superior capacity when compared with a lithium-ion battery.

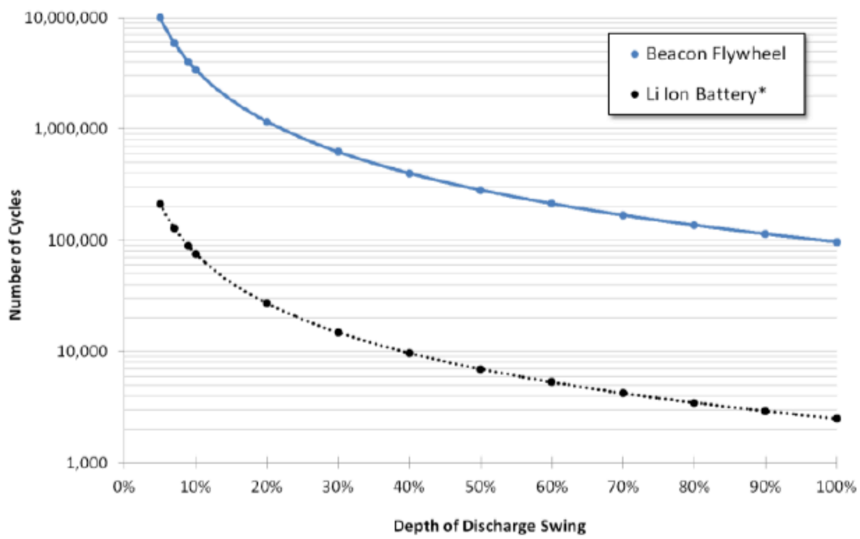

Figure G-2. Flywheel Cycle Life versus Lithium-Ion Battery

Pumped Storage Hydroelectric Energy Storage

Pumped storage hydroelectric (PSH) energy storage is a mature technology that has been successfully implemented around the world in grid applications.

PSH stores energy as gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation reservoir. When demand is low or renewable energy production is high, a reversible turbine-generator pumps water from the lower reservoir to the higher one. When energy is needed for the grid, water is released down into the lower reservoir through the turbine-generator, generating electricity. The distance between these two reservoirs—be they natural bodies of water or artificial reservoirs—must be high enough to generate power.

Pumped storage is the most widely used form of storage for large electrical grids. More than 120,000 MW of PSH has been installed around the world,[3] many of which exceed 1,000 MW per installation.[4] PSH installations are site-dependent, relatively expensive, and have long lead times for permitting and construction. According to the U.S. Department of Energy:

> Pumped storage is a long-proven storage technology, however, the facilities are very expensive to build, may have controversial environmental impacts, have extensive permitting procedures, and require sites with specific topologic and/or geologic characteristics. As estimated in a report commissioned by EIA, the overnight cost to construct a pumped hydroelectric plant is about $5,600/kW…[5]

While PSH has a relatively high capital cost, its useful life is 50 years or more. Pumped storage is very efficient, with round trip efficiencies in modern PSH plants exceeding 80%. Figure G-3 shows the typical layout of a PSH project.

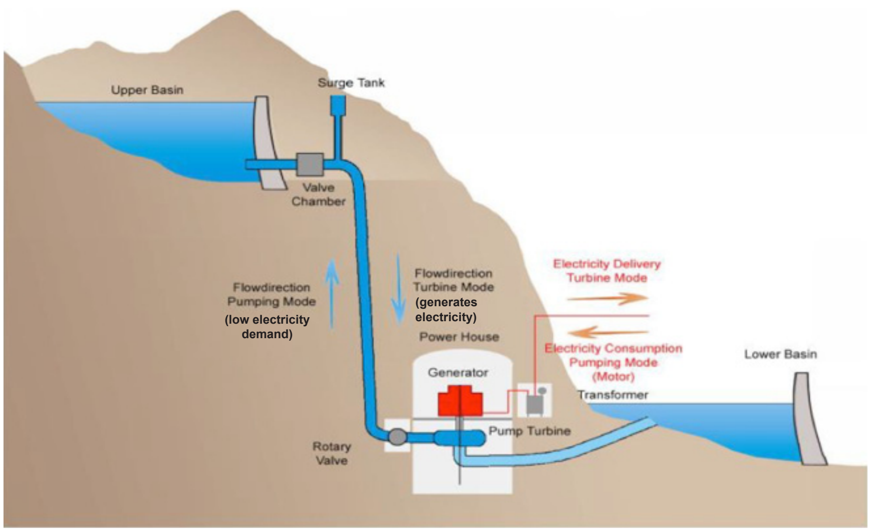

Figure G-3. Typical Pumped Storage Plant Arrangement[6]

PSH can provide peaking capacity and load shifting capabilities. While considered a quick-start resource, PSH takes a brief amount of time (about seven seconds) to start moving the water or to change direction through the turbine to produce electricity (its water column constant). These brief delays are limiting factors for single penstock systems.

3 "Packing Some Power," The *Economist*. May 3, 2012, http://www.economist.com/node/21548495?frsc=dg%7Ca (citing EPRI as their source).

4 https://en.wikipedia.org/wiki/List_of_pumped-storage_hydroelectric_power_stations. (This list is not complete. We are aware of projects not included in this list, and some smaller than the ones listed by this source).

5 http://www.eia.gov/todayinenergy/detail.cfm?id=6910.

6 Source: Alstom Power.

An adjustable speed pump turbine provides more precise control, thus providing operating flexibility, which in turn allows PSH to provide ancillary services (such as frequency regulation, spinning reserve, and load following) while generating and pumping. This can increase operating efficiencies, improve dynamic behavior, and lower operating costs.

Unlike a battery (which already has charge) or a flywheel (that has angular momentum), starting a PSH charging cycle requires high levels of electric current to start the motors necessary to pump water to the higher elevation. For example, a 30 MW PSH system would require 37.5 MW of capacity to start and serve the pumping-mode motor load (assuming an 80% round-trip efficiency). In Hawai‘i’s relatively small power systems, the starting current of PSH motor loads could exceed the short circuit limits of the existing transmission system.

To put this in perspective, a 30 MW PSH system on the Hawai‘i Electric Light grid would require starting 37.5 MW of motor load (assuming an 80% round trip efficiency). Because the typical daily peak demand is about 150 MW, starting the PSH motor represents an instantaneous 25% increase in load. This could cause currents to exceed the short circuit limits of the transmission system, which, without mitigation, would result in a significant frequency disturbance.

Some mitigation measures include installing multiple penstocks with smaller turbines, or installing several small pumps and staggering their start-ups. Incorporating PSH into Hawai‘i’s electric systems may also require investment in transmission facilities.

Over the years, a number of PSH projects have been studied and proposed in Hawai‘i. Table G-1 through Table G-4 show the results of numerous PSH studies in our service areas. These studies shows a wide distribution of the per unit capital cost data, reflecting the site specific nature of PSH.

O'ahu

Table G-1 summarizes the historical PSH projects studied on O'ahu. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Kapa'a Quarry	No data	No data	No data	No data	No data
Ku Tree Reservoir	No data	No data	No data	No data	No data
Nu'uanu Reservoir	No data	No data	No data	No data	No data
Koko Crater	1994	160.0	7.5	$161	$1,006
Ka'au Crater	1994	250.0	8.0	$256	$1,024
Kunia	2004	150.0	8.0	$189	$1,260
Mokuleia	2007	50.0	12.0	$197	$3,940
Hawaiian Cement	2008	7.0–74.0	8.0	No data	No data
Palehua	2014	200.0	6.0	$650	$3,250

Table G-1. Historical Studies of Pumped Storage Hydroelectric Projects on O'ahu

Hawai'i Island

Table G-2 summarizes the historical PSH projects studied on Hawai'i Island. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Pu'u Wa'awa'a	1995	30.0	6.0	$71	$2.367
Pu'u Anahulu	1995	30.0	6.0	$71	$2,367
Pu'u Enuhe	1995	30.0	6.0	$61	$2,033
Hawi	2004	10.0	5.0	$39	$3,900
Waimea	2004	2.3	12.0	$17	$7,391
Kaupulehu / Kukio	2006	50.0	5.0	$239	$4,780
Mauna Kea 15a	2016	56.4	5.0	$228	$4,046
Mauna Kea 5	2016	22.9	5.0	$105	$4,583
Mauna Kea 15a + 8c	2016	97.0	5.0	$422	$4,352
Kohala 12	2016	18.1	5.0	$89	$5,426
Kohala 8	2016	39.6	5.0	$239	$6,036

Table G-2. Historical Studies of Pumped Storage Hydroelectric Projects on Hawai'i Island

Maui

Table G-3 summarizes the historical PSH projects studied on Maui. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
Ma'alaea	1995	30.0	6.0	$83	$2,767
Honokowai	1995	30.0	6.0	$77	$2,567
Kahoma	1995	30.0	6.0	$104	$3,467
Pu'u Makua	2006	50.0	12.0	$169	$3,380
Lahaina West	2007	14.7	5.0	$62	$4,218
Lahaina West	2007	6.9	3.6	$39	$5,652
Makawao	2007	31.2	5.0	$220	$7,051
Kihei	2008	50.0	9.0	$315	$6,300

Table G-3. Historical Studies of Pumped Storage Hydroelectric Projects on Maui

Moloka'i

Table G-4 summarizes the historical PSH projects studied on Moloka'i. All costs are nominal dollars.

Site Designation	Study Year	Size (MW)	Hours of Storage	Estimated Capital Cost ($M)	Estimated Capital Cost per kW
East Moloka'i # 1	2007	3.0	5.0	$15	$5,000
East Moloka'i # 2	2007	1.0	5.0	$7	$7,000
West Moloka'i	2007	8.6	5.0	$57	$6,628

Table G-4. Historical Studies of Pumped Storage Hydroelectric Projects on Moloka'i

The vast majority of these studies are for PSH project less than 100 MW. Because the typical PSH installation in the United States is about 1,000 MW, there is limited data on the capital cost and performance for 100 MW PSH projects. Our research uncovered only a few instances of proposed (not constructed) comparably-sized PSH projects.

Based on limited data, we are using a capital cost estimate of $3,500 per kW in 2016 dollars for a 30–50 MW grid-scale PSH project, evaluating it against other storage options. This is optimistic; the average capital cost of all past studies itemized in the above tables is $4,050 per kW (not adjusted for inflation). The forecasted trend for PSH capital cost is flat in real terms, reflecting a mature technology.[7] These uncertain costs are in addition to the substantial permitting challenges any PSH project would face in Hawai'i.

[7] *E-storage: Shifting From Cost to Value Wind and Solar Applications.* World Energy Council. 2016. Table 6a: "Assumptions underpinning development of specific cumulated investment costs to 2030".

It bears noting that for the December 2016 PSIP update, we considered input from the Parties—in particular, Paniolo Power—regarding PSH. Paniolo Power did not submit a formal proposal about their interest in developing a PSH projects at Parker Ranch on Hawaiʻi Island. They did, however, provide input assumptions for consideration in our PSIP modeling analysis. After careful consideration, together we determined that Paniolo's input was essentially the same as ours, a key difference being Paniolo's higher capital cost. Thus, the PSIP modeling used our lower capital cost PSH assumptions. (See "Input Incorporated into Our PSIP Update Report" in Appendix B: Party Commentary and Input for details on our joint discussions.)

Our portfolio optimization models considered PSH an available storage resource option. Toward that end, we will consider proposals for PSH projects that cost effectively and competitively meet specifically determined power system needs.

Lithium-Ion Energy Storage Systems

Lithium-ion refers to a wide range of chemistries all involving the transfer of lithium-ions between electrodes during charge and discharge cycles of the battery.[8] Lithium-ion batteries are very flexible storage devices with high energy density, a fast charge rate, a fast discharge rate, and a low self-discharge rate, making lithium-ion batteries ideal for grid applications.[9]

Lithium-ion energy storage technologies have rapidly advanced to the point that they have recently become commercially available for grid-scale and distributed energy applications. These advances have been led by the development of advanced lithium-ion batteries for use in consumer electronics and automotive applications. According to a recent report from the Electric Power Research Institute (EPRI), battery energy storage "…is emerging as a potential technology solution for the utility industry because of a confluence of industry drivers related to both energy storage technology advancement as well as transformations in the electric power enterprise."[10]

The EPRI report identifies several trends within the energy storage industry:

- Technological advances in energy storage with active cycling capabilities, combined with longer useful asset lives.
- Declining costs and performance improvements in lithium-ion battery technologies.
- A pipeline of innovative research and development related to more advanced storage technologies, which could lead to lower costs and longer durations of energy storage.

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8 Energy Storage Association. http://energystorage.org/energy-storage/technologies/lithium-ion-li-ion-batteries.

9 *Lithium Ion Technical Handbook*. Gold Peak Industries (Taiwan), Ltd. http://web.archive.org/web/20071007175038/http://www.gpbatteries.com/html/pdf/Li-ion_handbook.pdf.

10 Electric Power Research Institute Inc. *Energy Storage Valuation Analysis: 2015: Objectives, Methodologies, Summary Results, and Research Directions*, Technical Update 3002006068, January 2016.

Capital costs for lithium-ion batteries are declining,[11] particularly as the use of lithium-ion for electric vehicle batteries rises. Even with their current commercial status, the expectations are for lithium-ion battery performance to improve, and for costs to continue to drop.

Grid-scale lithium-ion batteries installations can be easily scaled in size; have relatively short lead times for procurement, engineering, and installation; and have ultimate flexibility for permitting and siting them at available real estate or existing utility plant sites. Lithium-ion energy storage systems can be configured for a number of different applications at various voltage levels. This flexibility makes lithium-ion energy storage systems an excellent candidate for providing non-transmission alternatives in constrained areas.

Lithium-ion batteries themselves have a useful life through 4,000 to 5,000 normal charge-discharge cycles. More frequent use of the full charge-discharge capabilities of lithium-ion would shorten the life. Lithium-ion battery energy storage can be developed in two years or less, not counting regulatory approval lead-times. The typical efficiency of lithium-ion batteries is 80%–90%, depending on the application.

The use of lithium-ion batteries is largely being driven today by automotive and consumer electronic applications. Disposal of these kinds of lithium-ion batteries presents a challenge. Indeed, the increasing number of hybrid and electric vehicles (EVs) entering the market creates potential battery issues at an EV's end of life or when battery replacement is necessary. Several strategies have emerged for dealing with these "used" EV and hybrid lithium-ion batteries including recycling, remanufacturing, and reuse.

Recycling. Very few recycling facilities currently exist in the world, mainly because the cost to recycle a battery is high while commodity prices for the materials recovered from the recycling process are low.

Remanufacturing for Vehicles. Tesla has taken this approach, recycling their vehicle batteries in-house and reusing certain components for new batteries.

Reuse for Stationary Energy Storage. Lithium-ion batteries in EVs retain about 70% of their useful capacity at the end of their automotive service life.[12] Repurposed EV batteries are most useful for applications that require relatively light duty cycles (that is, daily charge and discharge cycles for load shifting and peaking applications). In these uses, their expected life is estimated to be about ten years. The primary cost associated with repurposing an EV lithium-ion battery is technical labor, so the cost is relatively low. Bloomberg reports that the cost of repurposed EV batteries for stationary storage applications might be on the order of half of the cost of new batteries (excluding the

[11] See for example: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/.

[12] http://www.nrel.gov/transportation/energystorage/use-analysis.html.

balance of plant components of a stationary energy storage application). Bloomberg predicts that by 2025, about one-third of all EV batteries will be repurposed for stationary storage.[13] Not all batteries are suitable for repurposing; advanced vehicle diagnostics can provide information about the state of the battery and its suitability for being repurposed as stationary energy storage. Nissan is pursuing the repurposing and refurbishing of batteries for stationary storage markets.

A number of the Parties commented about the technology status of lithium-ion batteries. As an example, in its comments filed on January 15, 2016 in Docket 2014-0183, Paniolo Power states:

> …while larger battery systems are starting to be built, batteries used for long duration, grid-scale applications must still be considered in the development phase… Battery technologies for long duration storage should be considered still under development as they are simultaneously attempting to improve the chemical compositions, storage capacity, operating life, disposal issues, and costs of batteries.[14]

However, our findings, based on current market conditions, show that lithium-ion battery technology has made substantial advances in cost and performance. Several vendors have reached a level of maturity and capitalization that they can offer performance guarantees on grid-scale lithium-ion battery systems. Kauai Island Utility Cooperative (KIUC) has contracted to purchase power from a solar PV project that incorporates a four-hour lithium-ion energy storage system. We find this indicates that long-duration storage technology has reached a level of technology maturity to support commercial applications.

Distributed Energy Storage Systems (DESS)

A distributed energy storage system (DESS)—mostly employing lithium-ion battery technology—is once located on a customer's property that helps control the customer's DG-PV generation. High penetrations of this DG-PV generation create many challenges: uncertain amounts of generation; inadequate dispatching or scheduling control; and distribution, and possibly transmission, systems capacity excesses. DESS batteries, optimally located and combined with a modernized grid, can mitigate many of these DG-PV challenges.

The load shifting capabilities from DESS can reduce the impacts to DG-PV generation and to distribution and transmission systems. DESS can also provide backup power, voltage correction, and the ability for a customer to participate in demand response programs.

[13] http://www.energy-storage.news/news/repurposed-ev-batteries-could-rival-first-life-storage-systems-bnef.

[14] Docket 2014-0183, Comments of Paniolo Power, January 15, 2016, pp 23–24.

Long-term benefits include improved system control and reliability of essentially uncontrolled DG-PV, and improved system reliability. DESS can also help reduce peak loads, help regulate voltage and frequency, and allow more time for service restoration during scheduled or accidental power interruptions.

DESS typically last for 15 years or more, are capable of over 3,000 charge-discharge cycles, have a net round trip efficiencies approaching 90%, and generally cost between 15¢–25¢ per kWh. While DESS batteries are improving, full power output durations for DESS are currently only about two hours.[15]

Hydrogen Energy Storage

Hydrogen is a versatile energy storage carrier, with high energy density, that holds significant promise for stationary, portable, and transport applications. Hydrogen could be used to "de-carbonize" applications that rely on natural gas.

In electricity applications, hydrogen can be produced through electrolysis with "excess" variable renewable energy (for example, energy available for production by wind and solar resources at times when the net system demand for electricity is low). Hydrogen can be stored under pressure in storage vessels or underground caverns. The stored hydrogen is then used in fuel cells or to produce electricity, thus providing a means of load shifting in grids with high penetrations of variable renewable resources.[16]

Figure G-4 depicts a simplified schematic of a hydrogen energy storage system.

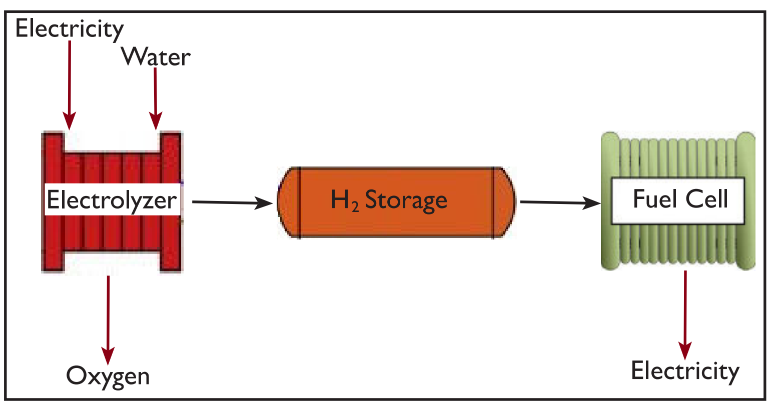

Figure G-4. Hydrogen Energy Storage System Schematic

While Europe has a relatively robust commercial supply chain for hydrogen production and storage for industrial uses,[17] hydrogen storage technology for electricity is still in the

[15] August 15, 2016 conference call between the Company and SunPower representatives.

[16] *Program on Technology Innovation: Hydrogen Energy Systems Development in Europe*, Technical Update 3002007274. Electric Power Research Institute, January 2016.

[17] *Ibid.*

research and development phase. In the United States, demonstration projects have been constructed that integrate wind turbines and solar PV with electrolyzer systems to produce hydrogen. In addition, a significant challenge towards commercializing hydrogen energy storage appears to be the ability to scale to larger sizes.[18] According to NREL: "… hydrogen can play an important role in transforming our energy future if hydrogen storage technologies are improved."[19]

Current conditions indicate that the availability of grid-scale commercial hydrogen storage systems is limited and thus not a viable near-term technology. Some of the Parties stated that we should consider hydrogen energy storage systems, however, none provided information as to this rationale. Further, the Parties did not submit any information or set of assumptions (including capital cost forecasts, operating cost forecasts, and round-trip efficiencies) that would allow us to model hydrogen energy storage systems.

Hydrogen energy storage systems hold great promise, and could very well substitute for the other energy storage technologies (such as flywheels, PSH, and lithium-ion batteries) considered for our PSIP, should they be more cost effective after attaining technological maturity.

We will continue to monitor developments in this technology, and as appropriate, include hydrogen energy storage in future power supply plan updates.

ENERGY STORAGE APPLICATIONS

Energy storage resources can be used to provide a number of services.

Inertia: Arrests frequency decline and stabilize the system using the ability of a machine with rotating mass. Batteries cannot provide inertia. Flywheels can provide inertia.

Frequency Response: Reduces the rate of change of frequency (RoCoF) to help stabilize system frequency immediately following a sudden loss of generation or load.

Regulation: Meets short-term changes in load and supply within seconds and minutes, because of solar fluctuations or the variable wind resources.

Replacement Reserves: Restores the above faster services after they are deployed to be ready for the next event or further changes in net load. Replacement Reserves are deployed in the minutes-to-hours timeframe and provide capacity to restore system

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[18] http://www.renewableenergyworld.com/articles/2014/07/hydrogen-energy-storage-a-new-solution-to-the-renewable-energy-intermittency-problem.html.

[19] http://www.nrel.gov/hydrogen/proj_storage.html.

frequency to 60 Hz following a contingency event or supplement Regulating Reserves because of forecast errors.

Load Shifting: stores energy for use at a later time to serve demand.

Table G-5 summaries the applications, uses, duty cycles, technologies, and sizes of energy storage systems.

<table>
<tr><th>Application</th><th>Duration</th><th>Storage Duty Cycles</th><th>Depth of Discharge</th><th>Energy Storage</th><th>Sizes Available to Planners (MW)</th></tr>
<tr><td>Inertia</td><td>Seconds</td><td>5,000 per year</td><td>Deep:
up to100%</td><td>Flywheels</td><td>10</td></tr>
<tr><td>Frequency Response</td><td>Up to
30 minutes</td><td>~10 per year</td><td>Deep:
up to100%</td><td>Lithium-Ion BESS</td><td>1, 5, 10, 20, 50, 100</td></tr>
<tr><td rowspan="2">Regulation</td><td rowspan="2">Up to
30 minutes</td><td rowspan="2">~15,000 per year</td><td rowspan="2">Shallow:
20% to 50%</td><td>Lithium-Ion BESS</td><td>1, 5, 10, 20, 50, 100</td></tr>
<tr><td>PSH</td><td>30, 50</td></tr>
<tr><td>Load Shifting</td><td>1–8 hours</td><td>Daily</td><td>Deep:
up to100%</td><td>Lithium-Ion BESS
PSH
CSP with Storage</td><td>1, 5, 10, 20, 50, 100;
2 for grid support
30, 50
100</td></tr>
</table>

Table G-5. Updated PSIP Energy Storage Applications, Sizes, and Technologies

In theory, certain configurations of energy storage installations could potentially be used for more than its primary purpose. For instance, a load shifting battery can also provide some regulation service if required. A contingency battery could, in theory, provide some load shifting. A 20 MW, 30-minute hour battery (that is, 10 MWh) could provide 10 hours of load shifting storage if the output of the battery system is limited to 1 MW (1 MW x 10 hours = 10 MWh). The key to the "stacking" of such applications is to closely manage the battery's charge and discharge cycling to maintain its useful life based on its designed application. Even in such cases, a higher capacity battery, or less reliable performance and availability of services, may be necessary when "stacking" applications.

Cost Assumptions Related to Energy Storage

Figure G-5 depicts the underlying constant 2016 dollar assumptions for the capital costs associated with selected sizes, technologies, and applications for energy storage systems assumed in the 2016 updated PSIP. (Refer to Appendix J: Modeling Assumptions Data for the specific capital cost assumptions for energy storage resources.)

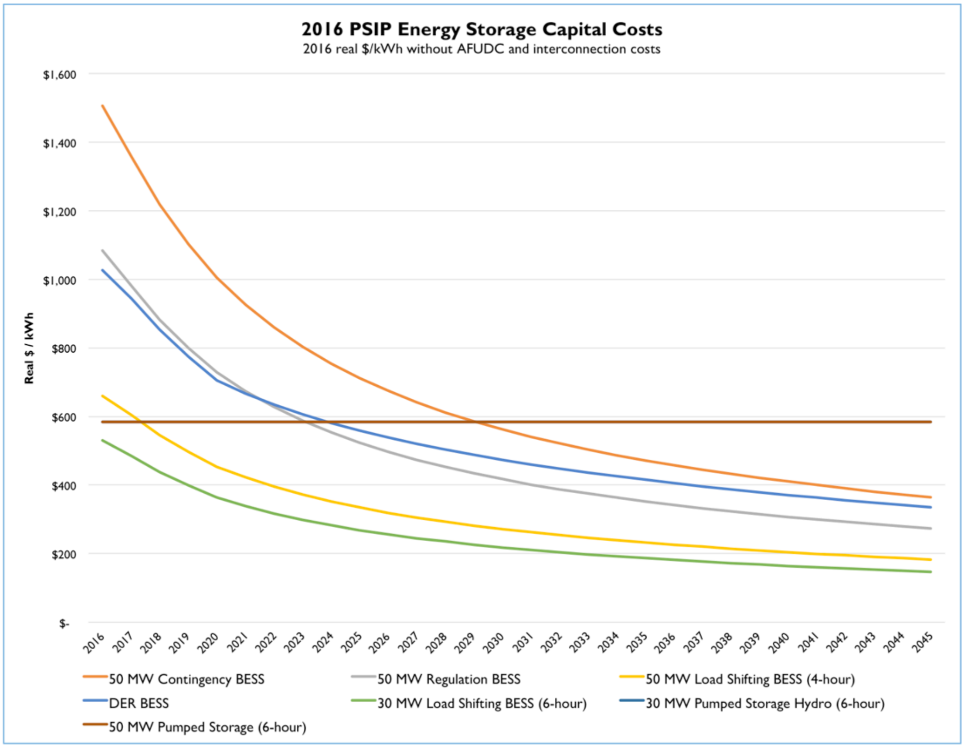

Figure G-5. 2016 Updated PSIP Energy Storage Capital Costs

The method for determining the capital and operating costs assumptions for energy storage systems was largely the same as for new grid-scale generating facilities. The primary source of data for current prices and forward curves was IHS Energy consultants. Prices were adjusted for Hawai‘i using RSMeans city indices. Prices were adjusted upwards by 4% to account for the Hawai‘i general excise tax.

Adjustments to BESS prices and costs were made based on the different applications. The application affects the "duty cycle" of the BESS, which in turn drives certain design parameters including the spacing of cells to better dissipate heat (longer duration storages requires more spacing, resulting in larger footprints) and air conditioning requirements. More frequent and deeper discharge of BESS requires replacement of battery cells more often in order to maintain output.[20]

5-5-5 Battery Initiative

Substantial investments in such initiatives are intended to make significant progress toward developing a breakthrough technology that significantly advances the power and reliability of energy storage systems while dramatically reducing costs. One such venture is the 5-5-5 battery initiative.

[20] Some vendors oversize the battery from the start, so that as the batteries degrade over time and the project's output declines to the customer's specified output requirements. Others provide warranty wraps where they replace cells as they degrade so that the desire output is maintained.

In 2013, the United States Department of Energy awarded the Joint Center for Energy Storage Research (JCESR), led by Argonne National Laboratory, with a $120 million grant to address "the scientific and engineering research needed to advance the next generation of electrochemical energy storage for both transportation and the grid."[21]

In a written statement before the Subcommittee on Energy Committee on Science, Space, and Technology of the United States House of Representatives, Director George Crabtree explained the vision and mission of JCESR through this grant:

> JCESR's vision addresses the two largest energy sectors in the U.S.: transportation and the electricity grid, which together account for two-thirds of our energy use. Our vision is aggressively transformative: to enable widespread penetration of electric vehicles that replace foreign oil with domestic electricity, reduce carbon emissions, and lower energy use; and to modernize the electricity grid by breaking the century-old constraint of matching instantaneous demand with instantaneous generation, enabling widespread deployment of clean and sustainable but variable wind and solar electricity while increasing reliability, flexibility and resilience. Both transformations can be achieved with a single disruptive breakthrough: high-performance, low-cost electricity storage, beyond today's commercial lithium-ion technology. JCESR's vision is to transform transportation and the grid with the next generation beyond lithium-ion electricity storage.
>
> JCESR's mission goals are to provide two prototypes, one for transportation and one for the grid, which, when scaled to manufacturing, are capable of providing five times the energy density at one-fifth the cost of commercial batteries in January 2012 when our proposal was prepared, summarized by the shorthand expression "5-5-5".[22]

JCESR implemented and continuously refines a new paradigm for battery research and development that integrated discovery science, battery design, research prototyping, and manufacturing collaboration in a single, highly interactive organization. JCESR expects this new paradigm to accelerate the pace of discovery and innovation and shorten the time from conceptualization to commercialization.

At the date of this statement, JCESR research has resulted in 26 invention disclosures with a dozen patent applications, and has selected and begun to converge four next-generation prototype concepts. In addition, JCESR is testing several candidate materials and batteries in half-cell and full cell prototypes.

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[21] *Grid Energy Storage*, published by the U.S. Department of Energy, December 2013. p 42.

[22] Written Statement of George Crabtree, Director, Joint Center for Energy Storage Research (JCESR), Argonne National Laboratory, University of Illinois at Chicago. Before the Subcommittee on Energy Committee on Science, Space, and Technology United States House of Representatives; Hearing on: Department of Energy (DOE) Innovation Hubs, June 17, 2015. pp 1–2.

H. Renewable Resource Options for O‘ahu

O‘ahu, Hawai‘i’s most populous island, could be challenged to meet the state’s 100% renewable generation goal using currently technology despite its relatively high resource potential for DG-PV. A main reason: O‘ahu has the lowest grid-scale wind and grid-scale solar PV resource potential relative to the demand for electricity because of the limited land area available for development.

Although other renewable resources may emerge, we have identified the following existing and emerging renewable energy resources that could attain 100% renewable generation on O‘ahu:

- DG-PV as a component of DER
- Grid-scale solar PV and grid-scale (onshore) wind
- Offshore floating platform wind
- Interisland transmission connected to off-island renewable resources
- Hydrokinetic (ocean) energy

Each resource has the *potential* for generating bulk quantities of energy to meet the renewable generation goal, however, each also faces impediments to realizing its full potential. Each option was discussed with the Parties during the development of this updated PSIP. A few of the Parties asserted that one or more of these options holds the answer to attain 100% renewable generation on O‘ahu. A deeper analysis reveals that the realities could be different for a number of reasons.

All of these renewable resource options are discussed here in detail: their potential, their technical capabilities, their potential cost, and their current status, and their associated risk factors.

MEETING HAWAI'I'S RENEWABLE ENERGY GOALS

Our April 2016 updated PSIP incorporated a number of changes to the input assumptions. The most notable new assumptions include: the revision to Hawai'i's Renewable Portfolio Standards (RPS) upwards to 100% by December 31, 2045; and new, refined estimates of the remaining developable renewable resource potential on O'ahu (defined to include existing commercially available zero-carbon renewable technologies).

Grid-Scale Renewable Options

NREL, as requested by the Companies, conducted an independent detailed analytical study that estimated the technical renewable resource potential on O'ahu, Maui, and Hawai'i Island. Constructive discussions with the Parties resulted in NREL revising these resource potentials to reflect different criteria.

The NREL report is a "top-down" analysis of resource potentials, based on publicly available wind and solar data bases, and a variety of "exclusions" of areas where development is known to not be possible (for example, urban areas, parks, and highly sloped areas). The NREL resource potential results provide an important data point for wind and solar PV resource potentials on O'ahu. Any such top-down estimate is likely to *overstate* the actual resource potential, since a top-down analysis does not investigate site specific circumstances for every possible site. In addition to land areas with slopes less than 10% for which PV is already an approved use, NREL's grid-scale solar potential for O'ahu assumes that all Agricultural B and C class land is used for solar. Because Agricultural B and C lands currently have area restrictions associated with PV use, *the developable resource potential could be substantially less than the NREL estimates*.

Two months after NREL submitted its revised report, an Ulupono representative (Dr. Matthias Fripp) suggested that the technical resource potential for grid-scale solar PV and grid-scale wind was substantially more than those presented in the NREL report. Subsequently, we also included these higher potential amounts in our analysis.

The NREL study and Ulupono's assertion are not intended to justify a definitive course of action. Rather, these study estimates inform planners and policy makers as to the availability and amount of renewable energy resources, based on existing technologies and land availability. Given O'ahu's energy demand, additional renewable energy resources will likely be needed beyond what is available from the high DG-PV potential and grid-scale wind and solar potentials identified by NREL. This risk is substantial enough that policy makers, project developers, and regulators would be prudent to consider today how additional resources *might* be developed should that turn out to be the best option to achieve the state's energy goals. These options include offshore wind, hydrokinetic technologies, interisland transmission cables, or other new technologies—all of which face their own challenges for implementation.

Offshore Energy Alternatives

Offshore floating platform wind technology is currently in the pilot project phase. The very first offshore wind facility ever developed in the United States, the Block Island Wind Project off the coast of Rhode Island, is only now achieving commercial operation (utilizing fixed bottom platforms). Other projects are also being developed. Clearly, the offshore wind power market in the United States is still in its early stages, but interest appears to be increasing. Success in deploying offshore wind resources to meet Hawai‘i's renewable energy goals requires additional industry success for full-scale operation; *and* a sustained effort by federal and state agencies, project developers, community leaders, and the Companies to plan for the possible utilization of this resource.

Some of the Parties suggested that wave or tidal power could substantially contribute to Hawai‘i's energy needs. The construction, development, and operational issues associated with these forms of hydrokinetic energy are very similar to those that apply to floating platform wind projects. The technical and commercial maturity of hydrokinetic energy, however, lags substantially behind that of offshore wind.

Interisland transmission cable technology is commercially ready, and has the credible potential of sharing renewable resources among all interconnected islands. Its feasibility for Hawai‘i, however, is uncertain because of the significant environmental, capital investment, cultural, social, permitting, and development challenges associated with realizing potential benefits.

DISTRIBUTED ENERGY RESOURCES AND DG-PV

Distributed energy resources (DER) provide a core component of the potential renewable additions to the islands. DER can take many forms and encompass several approaches, including demand response, energy efficiency, electric vehicles, customer-owned generation, and customer-owned storage technologies.

The Market Potential of DG-PV

As we evaluate the landscape today, the most significant form of DER is distributed generation photovoltaics, or DG-PV: solar PV generation installed at the homes and businesses of Hawai‘i.

DG-PV plays an important role and is a critical component in achieving 100% renewable energy on O‘ahu. The implementation, timing, and adoption of residential and commercial solar generation, however, is not fully within our control, nor necessarily the Commission's. Rather, it will be dictated in large part by the individual decisions of businesses and homeowners in response to products and service offerings.

The adoption of DG-PV is primarily driven by customer economics, which is then driven by two factors: the benefits of the DG-PV system to the customer (for example, avoided electricity purchases from the utility and compensation received for exports to the grid) and the capital and operating cost of the DG-PV system. We forecasted DG-PV adoption in two ways. First, for the market DG-PV forecast we assumed that compensation to DG-PV customers for exports is either zero (self-supply and SIA) or based on the cost of a grid-scale solar plant (future grid-export). Second, we forecasted a high DG-PV case based on the assumption that 100% of the single-family residential electricity sales would be offset by DG-PV by 2045 and roughly 20–25% of the total commercial sales would be offset by DG-PV in 2045. Customer economics were not addressed in developing the high DG-PV case. Achieving this higher level of DG-PV adoption will likely require mandates or significant additional customer incentives.

Table H-1 depicts the total projected installed capacities of the optimized DG-PV forecasts for the RPS milestone dates for the entire planning period of the updated PSIP.

Milestone Date	Market DG-PV Forecast	High DG-PV Forecast
December 31, 2015[1]	471 MW	471 MW
December 31, 2020	856 MW	858 MW
December 31, 2030	1,169 MW	1,671 MW
December 31, 2040	1,517 MW	2,562 MW
December 31, 2045	1,697 MW	3,008 MW
Total Growth (2015–2045)	1,226 MW	2,537 MW
Growth Percent 2015–2045	360%	639%

Table H-1. DG-PV Forecasts Under Market and High Scenarios

In developing the 2016 updated PSIP, we have sought to estimate the likely rate of DG-PV adoption, ensuring any plan is robust enough to encompass higher or lower adoption rates while maintaining a path towards a 100% RPS. Our PSIP takes these sensitivities into account. We are committed to continuing to evaluate and optimize DG-PV under various adoption rates. DG-PV alone, though, cannot meet the 100% RPS target for Hawai‘i.

The Technical Potential of DG-PV

The Company is exploring ways to develop estimates of the technical potential of DG-PV. Until recently, insufficient detailed data hampered our efforts. This situation, however, is beginning to change and, as a result, we are investigating several tools that may soon become available for this purpose.

Google’s Project Sunroof

Google’s Project Sunroof[2] is one such promising application. Google’s Project Sunroof enables homeowners and solar installers to estimate the potential energy cost savings a residential electric customer can gain from a rooftop solar PV installation. Google recently expanded Project Sunroof to include a data explorer tool. The data explorer provides an estimate of total rooftop solar potential for a specified community, although coverage is not currently available in Hawai‘i. Project Sunroof combines the power of Google Maps with databases and other information.

[1] Does not include customer-side Feed-In Tariff (FIT) projects.

[2] (https://www.google.com/get/sunroof#p=0).

That information includes:[3]

- Imagery and three-dimensional modeling and shade calculations from Google.
- Weather data from the National Renewable Energy Laboratory (NREL).
- Utility electricity rates information from Clean Power Research.
- Solar pricing data from NREL's Open PV Project, California Solar Initiative, and NY-Sun Open NY PV data.
- Solar incentives data from relevant Clean Power Research, Federal, State, and local authorities as well as relevant utility websites.
- Solar Renewable Energy Credit (SREC) data from Bloomberg New Energy Finance, SRECTrade, and relevant state authorities.

Project Sunroof currently covers roughly 43 million buildings in portions of 42 states and in Washington D.C. Using three-dimensional models derived from aerial images, Project Sunroof estimates the amount of sun reaching a rooftop from various positions in the sky, the available space for rooftop solar panels, the amount of energy production given typical weather conditions for that area.

Project Sunroof processes aerial images to create a high-resolution 3D digital surface model. Solar energy can be separated into two types: direct normal irradiance (energy directly from the sun) and diffuse horizontal irradiance (energy from other parts of the sky). The entire surface of the earth receives both types. Project Sunroof considers both types under typical weather conditions throughout the year. The typical weather data includes cloud cover, wind & temperature data and is sourced from NREL. In other words, Project Sunroof estimates the solar potential for a given point on a roof, for a particular hour in a typical year, taking into account roof pitch and azimuth, shade, and typical weather data.

Project Sunroof's model identifies rooftop outlines from rough building sizes available in Google Maps, then uses Machine Learning and other heuristic information (such as green objects) to estimate the extent of each rooftop. For example, rooftop areas covered with tree branches are often ignored for the purposes of estimating solar potential. The model then counts segments of the roof with space for at least four contiguous 250 watt PV panels, and only considers the rooftops that have the potential with space for at least 2 kW of energy.

[3] Project Sunroof Technology: https://www.google.com/get/sunroof/faq/.

The technical potential, then, is the amount of energy that can be generated from panels that receive at least 75% of the solar energy received by ideally oriented and unshaded panels, irrespective of financial or societal constraints. This total technical potential can be segmented by cities, states, zip codes, and census tracts—and can be segmented into north-facing, east-facing, south-facing, west-facing, and flat roof segments as well as panel azimuth and tilt.

The Company discussed with Google the possibility of using the Project Sunroof databases to estimate potential individual distribution feeders. The Project Sunroof tool, however, cannot currently export Geographical Information Service (GIS)[4] layers that could be superimposed on our GIS maps of our distribution systems.. Google stated that an automatic program interface (API)[5] might be developed that would enable accessing GIS layers in a way that utilities could estimate, and plan for, the solar potential by feeders. Until such an API is developed, it may be possible to arrange for the transfer of this data on an ad hoc basis. Regardless, GIS data for Hawai'i is not currently available in Project Sunroof, although it's scheduled to become available in the near future.

Mapdwell's Solar System

Solar System, an interactive online rooftop solar mapping tool developed by Mapdwell (a Massachusetts Institute of Technology spinoff) allows users to estimate the rooftop PV potential for almost every building in a given city. Solar System provides solar PV potential and a comprehensive cost-benefit analysis for both residential and commercial addresses. Solar System has been used to quantify rooftop PV potential in Portland, Oregon, San Francisco, New York City, and Boulder, Colorado.[6] Smithsonian Magazine called Solar System the "most accurate solar map in the United States" in 2013 and Denmark's Sustainia think-tank selected Solar System as one of 2015's top ten sustainable solutions world-wide.

Solar System uses three-dimensional elevation data to create a surface model of the sample terrain that accounts for the shape of building rooftops and structures, existing infrastructure, and tree foliage. Solar System also incorporates historical weather data for each location to account for varying weather conditions. This methodology calculates the amount of sunlight that strikes every point of a rooftop over the course of every hour of the year and yields highly granular and accurate estimates of generation potential.

Solar System defines a Solar Access Index (SAI), which is the solar PV electric yield of any given surface relative to the best possible yield within a given sample. SAI values

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4 GIS technology allows "layers" of information, based on geography, to be overlaid and compared. Examples of GIS layers include topography, streets, residential addresses, and asset locations.

5 Typically, an API provides the protocols that allow two different software systems to interact. For example, an API could be developed by Google that would allow a GIS software application to access and utilize the data in the Project Sunroof application.

6 https://www.mapdwell.com/en/solar/buzz.

range from zero (that is, no solar PV potential) to 1.0, the maximum possible solar PV potential. Solar System screens each surface and eliminates those with SAIs below 0.5. It further identifies surfaces with SAIs of 0.75 or greater as "high PV potential." Using detailed assumptions regarding installation costs, electric rates, and local incentives, Solar System returns financial feasibility and environmental benefits of solar PV installations. Metrics provided to the user of Solar System include: cost to owner, monthly revenue, system size in kW, payback period, and carbon offset estimates.

Solar System can assess solar PV economic potential of individual home and business owners, and provide policymakers with area-wide assessments of distributed solar PV potential. Mapdwell also offers additional data services and GIS databases of solar potential.

We have spoken with Mapdwell; we are considering their Solar System as a potential tool for assessing rooftop PV potential across residential, commercial, and industrial buildings in our service areas.

GRID-SCALE PV AND GRID-SCALE WIND POTENTIAL

The Companies retained NREL to determine the maximum resource potential for on-island grid-scale PV and grid-scale wind for O‘ahu, Maui, and Hawai‘i Island for our April 2016 PSIP. NREL delivered that report on March 17, 2016.

Based on Party input to the April 2016 PSIP, we asked NREL to conduct additional analysis regarding the grid-scale wind and solar resource potentials for O‘ahu. NREL’s expanded report, *Utility-Scale Onshore Wind, Utility-Scale PV, and CSP Potential Resource*, assessed these three resource potentials. (Since these utility-scale resources are owner agnostic, they are better characterized by the term “grid-scale”.) NREL delivered this additional study on July 21, 2016. (Appendix F: NREL Reports presents and discusses this updated resource potential study, and three others, in detail.)

At our request, NREL reran the grid-scale wind and grid-scale PV portion of this study for O‘ahu based on Stakeholder input. Here, the focus is on these O‘ahu results.

During stakeholder meetings, Dr. Matthias Fripp (representing Blue Planet and Ulupono) initiated a discussion with several Company representatives about the maximum renewable resource potential on O‘ahu. That discussion entailed the NREL resource potential study and used as input assumptions to our modeling analysis for that PSIP.

Dr. Fripp suggested that the NREL resource potential study’s screening assumptions were too conservative and should be changed as follows:

- Land slopes for potential grid-scale PV installations be increased to 10% because the 5% land slope is too conservative.
- Agricultural B and C class land be considered to assume that 100% of this land is available for PV development—even though special use permits are required for grid-scale PV installations exceeding 10% of a parcel or 20 acres, whichever is less.
- Land resolution be decreased from a four-kilometer square to a more granular one-kilometer square to potentially include projects that could be developed on smaller parcels of land.
- Wind project density of 3 MW per square kilometer was too low and should be raised to 8.8 MW per square kilometer.

We consulted with NREL about these revisions. NREL’s data showed that their wind project density is consistent with industry practices. The four- kilometer square data is publicly available and, as such, results in analysis that is both replicable and transparent. Thus, NREL did not change either of these factors (the third and fourth bullets above). At our request, NREL did conduct additional studies using land slope up to 10% and including 100% of Agricultural B and C land.

It's important to note that we are using these NREL study results in our modeling analysis as the technical (or *theoretical)* maximum potentials. In actuality, much less than 100% of the resulting resource potential land is likely to be available for development.

Nonetheless, we have used NREL's resource potentials in our modeling analysis; E3 has performed sensitivity analyses using Dr. Fripp's resource potentials to understand the impact of these higher resource potentials.

Table H-2 depicts the difference between our initial input assumptions and those assumed by Ulupono as a result of their suggested changes. Note that these Ulupono amounts are projected, and not necessarily the results of the revised NREL resource potential study.

Resources (MW)	Hawaiian Electric (April 2016 PSIP)	Hawaiian Electric (December2016 PSIP)	Ulupono (Dr. Fripp)
Onshore Grid-Scale PV	793	2,970	6,583
Market DG-PV Forecast	1,204	1,308	n/a
High DG-PV Forecast	1,592	2,101	n/a
Onshore DG-PV Potential	n/a	n/a	3,022
Onshore Grid-Scale Wind	162	162	2,680
Offshore Grid-Scale Wind	800	800	800

Table H-2. Renewable Energy Resource Potential for O‘ahu

The onshore grid-scale PV potential is based on fixed tilt units with a capacity factor of greater than 20% sited on up to a 10% land slope; 100% of Agricultural B and C class land included; and a 1.5 inverter loading ratio. The onshore grid-scale wind is based on wind speeds greater than 6.5 meters per second.

To support his suggestion, Dr. Fripp wrote an extensive email (on September 24, 2016 after the Third Stakeholder Meeting) describing revised results of grid-scale solar PV potential (in an email on October 18, 2016) and gave a presentation (at the Fourth Stakeholder Meeting) explaining in detail the rationale for altering NREL's resource potential study. He discussed his research about the technical (*theoretical*) potential for rooftop DG-PV, grid-scale wind, and grid-scale solar PV on O‘ahu. Dr. Fripp also cited the report entitled *Development of SWITCH-Hawai‘i Model: Loads and Renewable Resources* published almost two years earlier in December 2014 by the Electric Vehicle Transportation Center, the result of work in his university classroom.

Dr. Fripp's estimated potential for rooftop PV is 3,022 MW (direct current) based on an assumption of 40% coverage of existing rooftops. This coverage assumption is based on

70% coverage of flat roofs (15% of total roofs) and 35% coverage of sloped roofs (85% of total roofs).

Dr. Fripp's estimated potential for grid-scale wind is estimated to be 2,680 MW. This is based on a density of 8.8 MW per square kilometer of land and no minimum capacity factors. The higher density is based on two factors: the Kahuku wind facility's density is 12.9 MW per square kilometer, and an NREL report estimates a high-end density of 5–8 MW per square kilometer.

This estimated grid-scale wind potential is broken out by annual capacity factor (Table H-3) and is based on 2007–2008 wind profiles.

Annual Capacity Factor	Available Wind (MW)
<12%	550
12% – 16%	558
16% – 18%	428
18% – 20%	125
20% – 22%	2
22% – 24%	198
24% – 26%	330
26% – 28%	48
28% – 30%	30
30% – 32%	50
32% – 34%	242
34% – 36%	119
Total	2,680

Table H-3. Technical Grid-Scale Wind Potential for O'ahu: Dr. Fripp Results

Annual Capacity Factor	Available Fixed Tilt PV (MW)	Available Single-Axis Tracking PV (MW)
<18%	1	-
18% – 20%	455	0.5
20% – 22%	1,118	356
22% – 24%	4,129	262
24% – 26%	1,955	
26% – 28%	43	1,982
28% – 30%	–	2,138
30% – 32%	–	493
32% – 34%	–	34
Total	6,583	5,266

Table H-4. Technical Grid-Scale PV Potential for O‘ahu: 20% Land Slope: Dr. Fripp Results

Dr. Fripp’s estimates of grid-scale PV potential are based on a 10% slope exclusion and development densities of 6 acres per MW(AC) for fixed-tilt PV and 7.5 acres per MW(AC) for single-axis tracking PV. For comparison purposes, the NREL grid-scale PV potential is based on a development density of 8.7 acres per MW(AC). Dr. Fripp’s analysis concludes that the technical grid-scale single-axis tracking PV potential is approximately 6,583 MW, while the technical grid-scale fixed tilt PV potential is approximately 5,266 MW. Both of these technical PV potentials are based on use of the same available land, thus their estimates are mutually exclusive: analysis should be based on 100% of single-axis tracking PV, 100% fixed tilt PV, or a mix of both totaling 100% use of available land.

Note first that the grid-scale wind, grid-scale single-axis tracking PV, and grid-scale fixed tilt PV are estimates of technical resource potentials, and second that they are estimates. In other words, these amounts represent technical maximum resource potentials. Many factors can combine to reduce these resource potentials: land access and ownership, community concerns, permitting issues, transmission infrastructure and access to transmission lines, cost, and the economic feasibility of building projects in the marginal (low-capacity factor) sites identified by both NREL and Ulupono. Conversely, there are factors that may increase the estimates (such as technical advances in PV module efficiencies).

Geographical Resource Potential Representations

While the technical resource potential of grid-scale PV and grid-scale wind on O‘ahu is a significant amount of nameplate capacity, a closer look reveals a more moderated reality of the resource potential that can actually be harnessed.

Grid-Scale PV Potential

Figure H-1 and Figure H-2 depict the potential grid-scale PV sites on Oʻahu as determined by the NREL resource potential study. These earth-map representations correspond with the Oʻahu maps in Figure F-19 through Figure F-22 in Appendix F: NREL Reports.

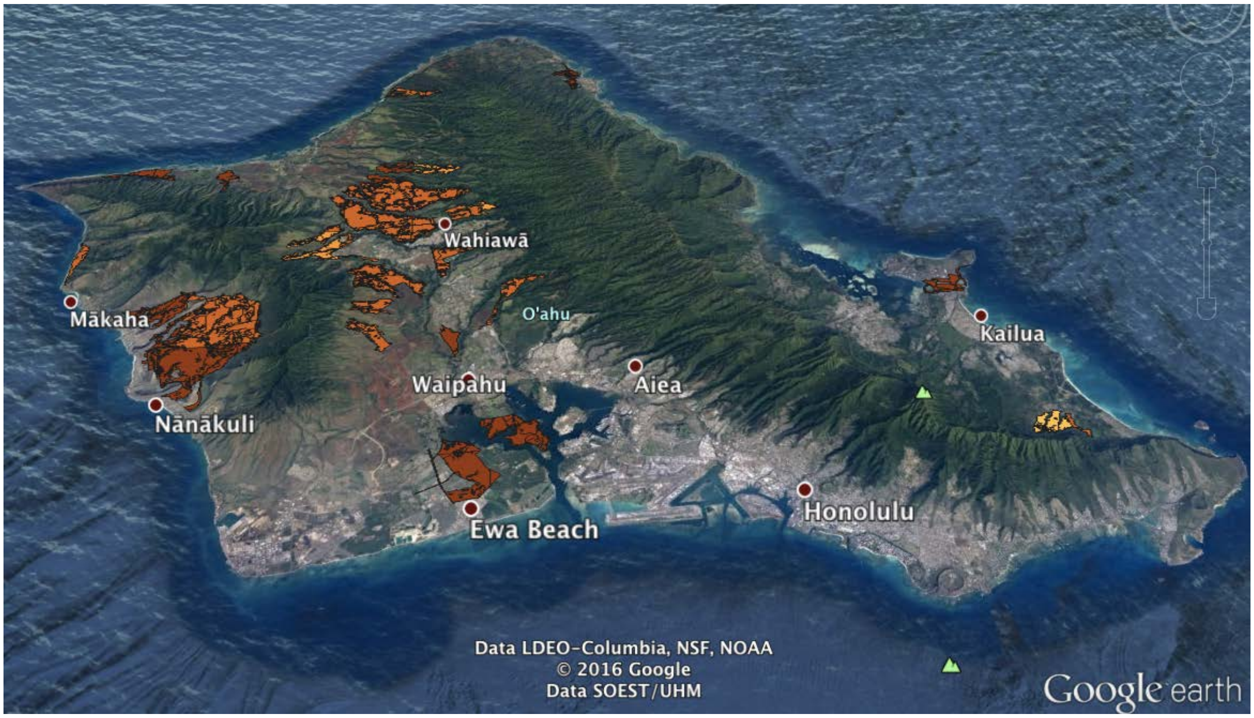

Figure H-1. Grid-Scale PV Development Potential for Oʻahu (NREL detail)

The map shows four areas of PV annual capacity factor percentages—the larger the percentage, the greater the grid-scale PV potential. These four color-coded areas are listed in Table H-5.

Color	PV Class	PV Potential (MW)
Dark Orange	20+	414–1,053
Orange	18–20	1,338–2,756
Light Orange	16–18	1,338–2,923
Yellow	14–16	1,338–2,970

Table H-5. Oʻahu Grid-Scale PV Class Designations

Refer to Table F-8: Grid-Scale Solar PV Potential for Oʻahu (MWac) on page F-6 in Appendix F: NREL Reports for a detailed breakdown of how these capacity factors translate into MW potential.

At the island-wide size depicted in Figure H-1, though, it is difficult to see the detail of the grid-scale PV potential, and the numerous noncontiguous and small areas that comprise the overall resource potential.

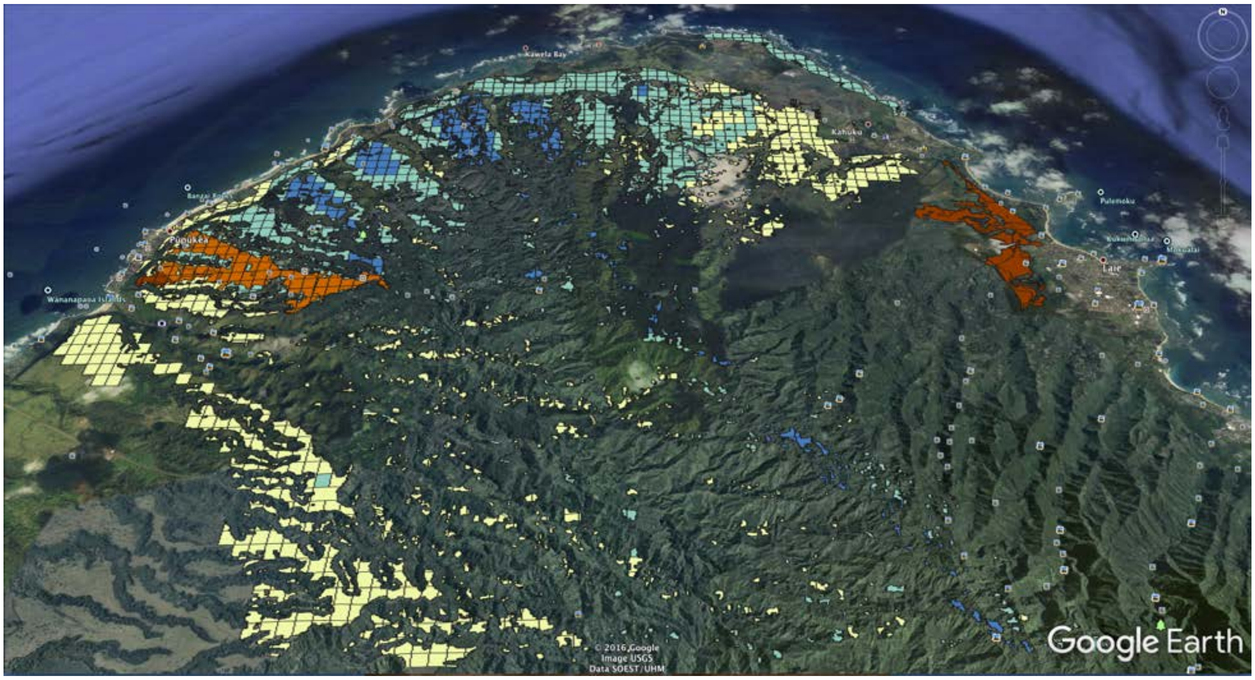

Figure H-2. Grid-Scale PV Development Potential for O'ahu (NREL North Shore detail)

From the perspective of Figure H-2, the four-kilometer square segments are clearly shown. There are a number of clustered segments that show the potential for large grid-scale PV installations. What is also clear are the numerous small grid-scale PV potential sites scattered throughout the center of the photo. Virtually all of these areas are situated on the foothills of the Ko'olau mountain range and the flatter sections of the mountain range's summit. This depiction is typical of the remainder of the island. Neither the feasibility of developing these small sites, nor the costs for installation, maintenance, and transmission from these sites, has been researched or evaluated.

The largest current grid-scale PV installation in Hawai'i is Waianae Solar. Located on the leeward side of O'ahu, mauka of Kamaile Academy and the Uluwehi community, the facility covers 198 acres; its installed solar modules generate 27.6 MWac of power.

Figure H-3 and Figure H-4 help gain a perspective, from two different viewpoints, of this sizeable grid-scale PV installation.

Figure H-3. Waianae Grid-Scale Solar Facility on O'ahu (broad under-construction viewpoint)

Figure H-4. Waianae Grid-Scale Solar Facility on O'ahu (close-up detail)

Figure H-5 and Figure H-6 show a geographical comparison of the NREL results for grid-scale solar PV potential with those of Ulupono representative, Dr. Fripp.

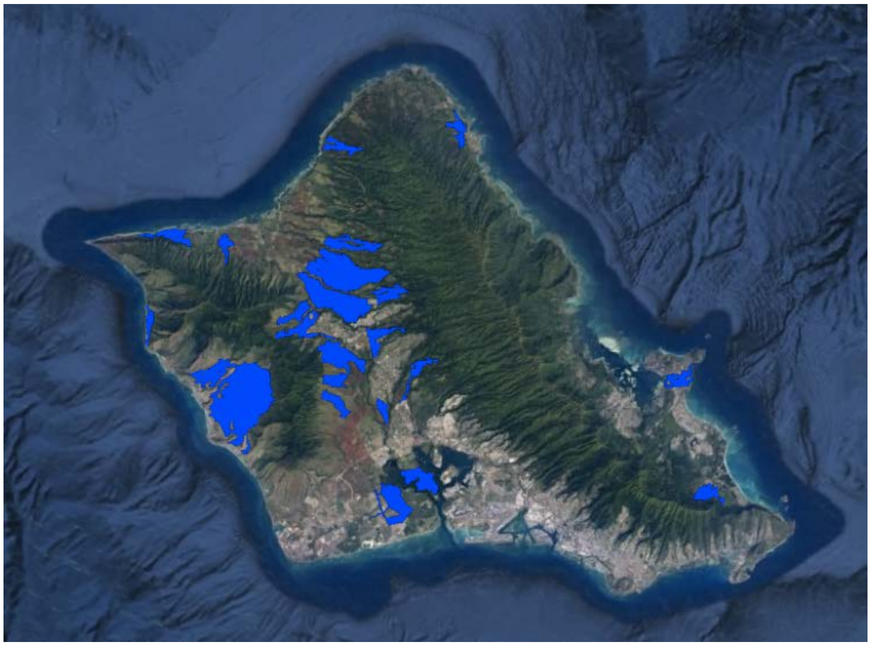

Figure H-5. Potential O‘ahu Grid-Scale PV Sites: NREL Revised Results

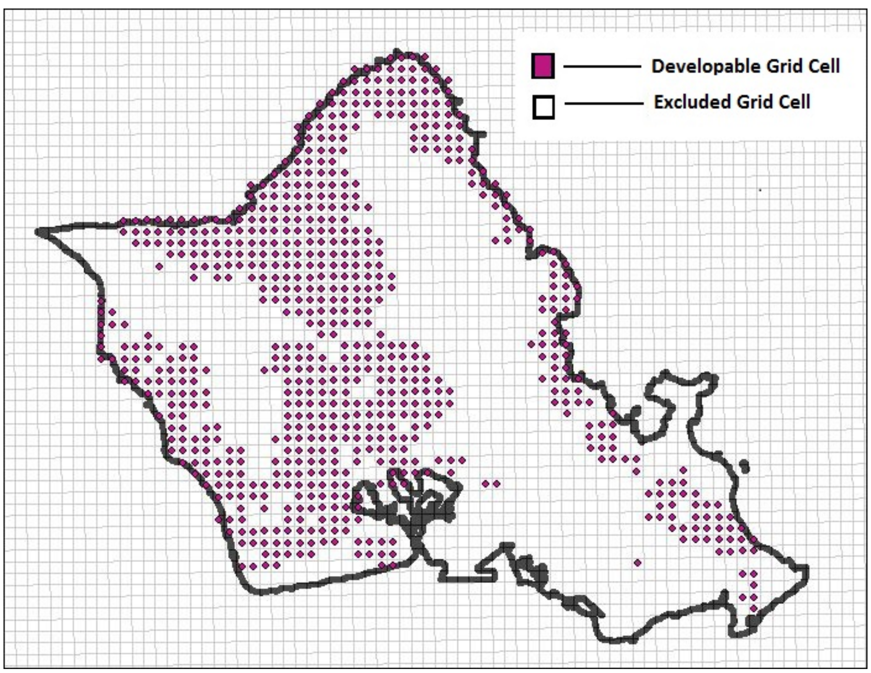

Figure H-6. Potential O‘ahu Grid-Scale PV Sites: Dr. Fripp Results

Grid-Scale Wind Potential

Figure H-7 depicts the potential grid-scale wind sites on O‘ahu as determined by the NREL resource potential study. This earth-map representation corresponds with the O‘ahu map in Figure F-10: Grid-Scale Onshore Wind Development Potential for O‘ahu on page F-19 in Appendix F: NREL Reports.

Figure H-7. Grid-Scale Wind Development Potential for O‘ahu (NREL detail)

The map shows three areas of mean wind speeds at 80 meters—the higher the speed, the greater the grid-scale wind potential. These three color-coded areas are listed in Table H-6.

Color	Speed Class	Wind Potential (MW)
Blue	8.5+	16–19
Blue-Green	7.5–8.5	68–81
Yellow	6.5–7.5	162–174

Table H-6. O‘ahu Grid-Scale Wind Speed Class Designations

Refer to Table F-5. Grid-Scale Onshore Wind Potential for O‘ahu (MWac) on page F-5 of Appendix F: NREL Reports for a detailed breakdown of how these capacity factors translate into MW potential.

The same issue of perspective holds true for the island-wide map for grid-scale wind potential depicted in Figure H-7 as for the grid-scale PV potential depicted in Figure H-1.

The overall resource potential comprises several concentrated areas together with numerous noncontiguous and small areas.

The North Shore of O'ahu shows the greatest potential for grid-scale wind, with virtually all the remaining sites scattered across the island in small segments.

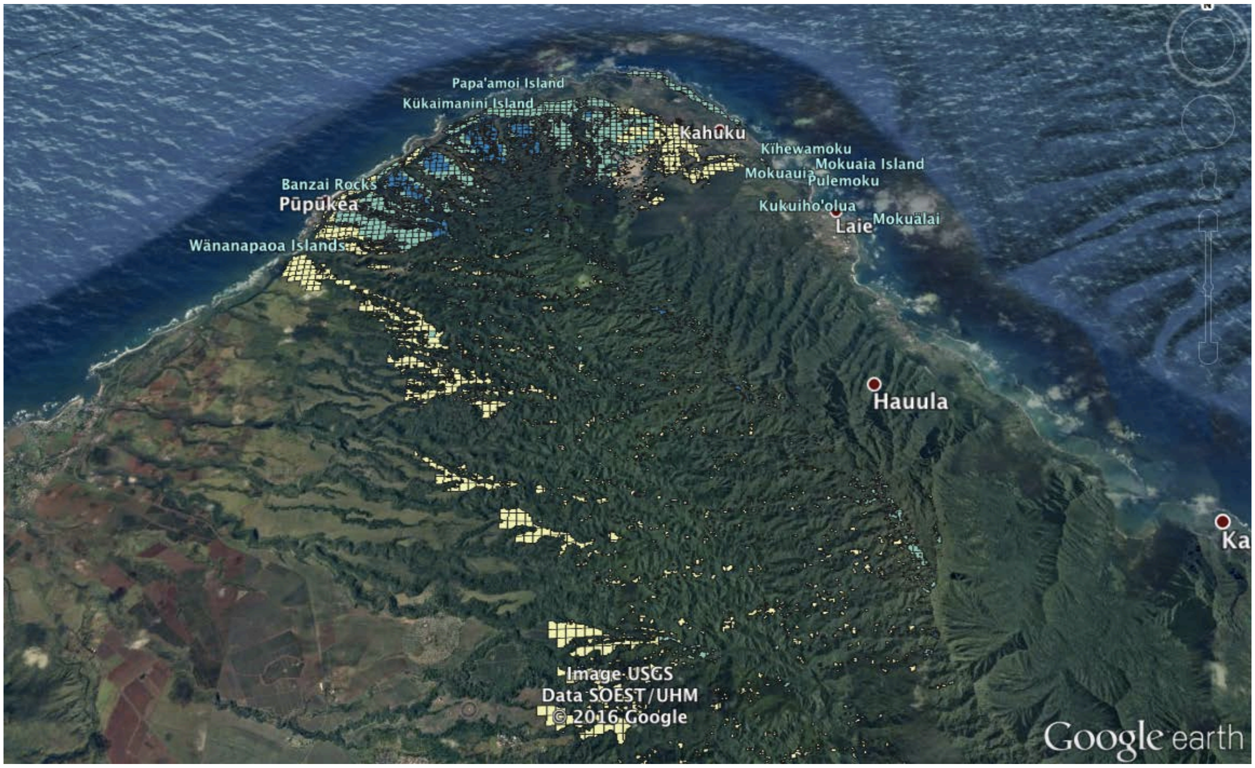

Figure H-8. Grid-Scale Wind Development Potential for O'ahu (NREL North Shore detail)

From the perspective of Figure H-8, the four-kilometer square segments are clearly shown. The clustered segments that are conducive to large grid-scale wind installations almost exactly match the segments that are conducive to large grid-scale PV installations (see Figure H-2 to compare). In the end, to achieve the maximum generation, these sites would have to be developed for both PV and wind.

Notice also that, as with grid-scale PV, numerous small grid-scale wind potential sites are situated on the foothills of the Ko'olau mountain range and the flatter sections of the mountain range's summit. This depiction is typical of the remainder of the island. The feasibility of developing these small sites, or the costs for installation, maintenance, transmission and interconnection from these sites, have not been researched or evaluated.

Figure H-9 (a more definitive representation of the grid-scale wind depicted in Figure H-7) and Figure H-10 show a geographical comparison of the NREL results for grid-scale wind potential with those of Ulupono representative, Dr. Fripp.

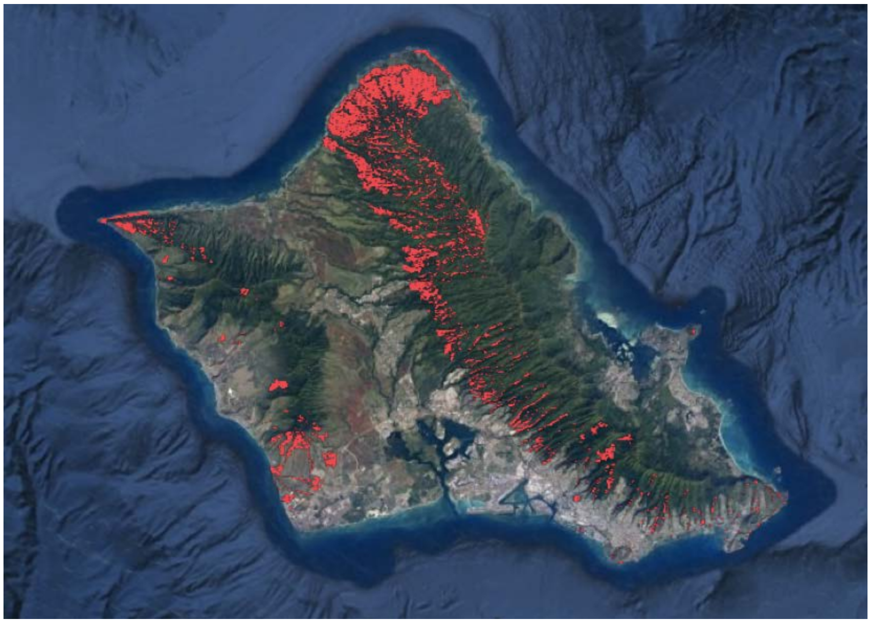

Figure H-9. Potential O‘ahu Grid-Scale Wind Sites: NREL Revised Results

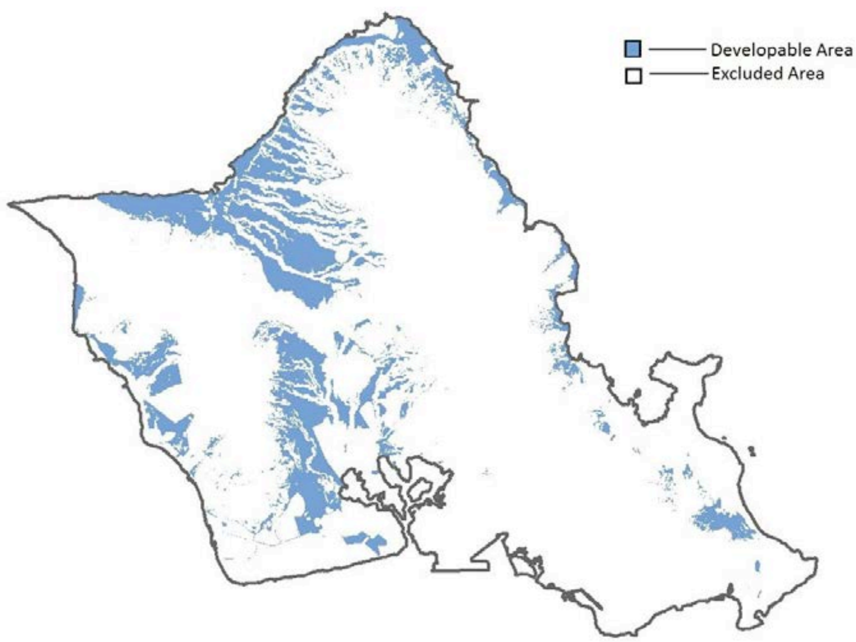

Figure H-10. Potential O‘ahu Grid-Scale Wind Sites: Dr. Fripp Results

In the Final Analysis

A thorough review of Figure H-1 through Figure H-10 indicates the substantial amount of land—under either analysis—necessary to realize these potential resources on Oʻahu. To realize the maximum grid-scale solar PV potential postulated by Dr. Fripp's analysis would require that approximately 10% of Oʻahu's land area be covered with solar panels.

The analyses conducted by NREL and Dr. Fripp represent the maximum technical potential for grid-scale solar PV and grid-scale wind on Oʻahu. These amounts, however, represent the *technical* developable potential, not necessarily *actual* developable potential as neither considers the reality of being able to develop any identified land parcel.

These developmental challenges include, but are not limited to:

- Community acceptance of a project at a given site, including its visual impacts.
- Competing land uses (for example, agricultural or other permissible uses).
- The actual ability to obtain Special Use Permits for Agricultural B and Agricultural C class lands beyond the 10% parcel or 20 acre threshold.
- Environmental issues and considerations.
- Geotechnical conditions associated with any particular parcel.
- Lack of developer interest in parcels that could accommodate only smaller project sizes.
- Lack of developer interest in parcels that could accommodate projects with relatively low capacity factors.
- Inaccessible or prohibitive development costs for remote parcels.
- Access, potential difficulty, and times associated with building new transmission facilities to access projects at remote parcels.
- Privately-held parcels might not be for sale or available for development.
- Potential higher capital costs for developing land with a greater than 5% slope.

All of these limiting factors will affect the ability to realize these resource potentials; all are *outside* the control of the Companies. Outside of these limiting factors, the State and local communities must also develop policies that will facilitate developing a substantial portion of these resource potential land parcels.

OFFSHORE FLOATING PLATFORM WIND ENERGY

Our April 2016 PSIP identified offshore floating platform wind energy as a potential resource option for meeting future renewable energy requirements. The proposed offshore wind project would be installed on floating platforms in 700–1,000 meter deep water off of the coast of O‘ahu. This section assesses the viability of such a successful offshore floating platform wind project.

Overview

Offshore wind energy installed on floating platforms has the potential to drive considerable growth in wind generation around the world. Whereas fixed bottom wind generation is generally limited to shallow waters, floating platform wind projects offer the potential to unlock considerable amount of wind energy potential along coastlines where the waters are too deep to accommodate fixed bottom installations (for example, west coast of the U.S. and Hawai‘i). Further, the ability to site wind in deeper waters, allows wind generation to be installed “below the horizon” where they are only partially visible or totally invisible from the shoreline, thus minimizing siting objections common with onshore wind development.

Potential for Lower Priced Energy

Floating platforms also have the potential to achieve lower cost than fixed bottom technologies due to the ability to assemble the fixed platforms in port and tow them into place at the site. This avoids deployment of expensive-to-charter heavy lifting vessels during the initial installation of the wind projects and in events where major repairs are required. As of today, however, floating platforms are quite a bit more expensive than fixed platform wind installations. Declines in capital cost for floating platforms are a function of successful deployment of full-scale prototypes and subsequent multiple deployments with well-engineered components that can be mass produced and replicable installation techniques. Even with a higher capital cost, floating platform wind provides the ability to install wind turbines in the ocean in areas where wind regimes are excellent for wind production. Therefore, floating platform wind might achieve levelized electricity production costs that are lower than fixed bottom wind due to the superior capacity factors that can be achieved with optimal siting of the wind projects.

Technical and Commercial Readiness

As of 2016, floating platforms for wind energy generation are not technically or commercially ready. Only a handful of pilot projects have been installed. Thus far, the few pilot floating platform wind projects have required government subsidies to be built; capital markets are still reticent to providing commercial financing for floating platform wind projects.

However, there are reasons to be optimistic with respect to the use of floating platforms for offshore wind projects. Certain vendors, including Principle Power and its WindFloat® technology, have achieved success with the deployment of prototypes in representative environments, and are moving towards deployment of full-scale, multiple platform installations within the next two the three years. However, these first full-scale projects will heavily rely on subsidies or other government-backed financial guarantees.

Interested Developers, Siting Process in Place

Two different developers are proposing projects in Hawai‘i utilizing Principle Power's WindFloat technology. This technology is considered to be the most advanced floating platform currently available, even though it still has to move beyond proof of concept into commercial status. A 25 MW project proposed off the Portugal coast for 2018 is expected to utilize the WindFloat technology[7] and, if successful, that project could signal that the technology is ready to be deployed on a commercial scale.[8]

Deployment of offshore floating platform wind in Hawai‘i is subject to a number of factors beyond just the technology. The U.S. Department of Interior Bureau of Ocean Energy Management (BOEM) leasing process for offshore sites has just started, and as part of that process, numerous stakeholders will need to be consulted including the U.S. Department of Defense, U.S. Fish and Wildlife, the Federal Aviation Administration, State of Hawai‘i Ports Division, and local interests including the local fishing industry. At least one of the developers has been active in engaging the community and the various agencies. BOEM issued a Notice of Call for Lease Proposals on June 24, 2016 providing a 45-day comment period by interested parties. The comment period was subsequently extended until September 7, 2016.

Competing Uses for Port Facilities

One of the primary cost advantages of floating offshore wind is the ability to assemble the platforms, with turbines installed, in port and then tow them into place. Two developers have indicated that they plan to construct and assemble each of the floating platforms, with towers and wind turbines, in a port facility in Hawai‘i. Port facilities in

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[7] http://www.offshorewindindustry.com/news/25-mw-floating-project-planned-portugal.

[8] Principle Power's technology was proposed for a 30 MW project off the coast of Oregon to be operational in 2017, but that project failed due to the failure to obtain a higher-than-market electricity price (driven by the still very high capital cost of the project). That project would have also required substantial government subsides.

Hawai‘i are subject to multiple competing uses particularly for importing goods and commodities for consumption within the State. There is a high demand for improvements to existing port facilities to accommodate existing and planned uses other than construction and fabrication of offshore wind platforms. Most of the demand for these improvements comes from those who have long-term needs, as opposed to offshore wind activities, which would represent a relatively short-term use of the constrained port space. Ultimately, the ability to utilize Hawai‘i ports for offshore wind will come down to a policy decision by the State of Hawai‘i.

Undersea Interconnections Required to Connect Offshore Wind

Offshore wind projects are interconnected to the onshore power grid through a gathering system, operating in the 34.5 kV range, that feeds into a floating substation and steps up the power to match the onshore voltage (138 kV for O‘ahu) for transmission and interconnection with the power grid. To date there has been very little experience with installing high capacity substations on floating platforms for operations in marine environments.

Capital Costs

The potential to achieve economies of scale for floating platform wind is driven primarily by the size of the wind turbines installed on the floating platforms. The largest wind turbine currently available is 6 MW. It is likely that an 8 MW turbine will be available within a few years. Longer term, there is an expectation that individual wind turbines will become available in even larger sizes, perhaps as large as 20 MW per machine.

Capital costs for offshore floating wind are expected to come down as floating platform technologies mature, more projects are built (likely with government support), and ultimately become mainstream evidenced by the ability to access equity and debt markets without the need for subsidies.

The two known interested developers in Hawai‘i have publicly stated that their projects would cost roughly $1.6 Billion to $1.8 Billion for each 400 MW project (or about $4,000–$4,500 per kilowatt) for commercial operation in the early 2020s. Based on available information, these cost targets appear to be optimistic, at least in the time frames proposed by the developers. However, given the high level of interest and effort in developing floating offshore wind technologies, it is likely that by the mid to late 2020s the technology will be considered commercial and prices will be competitive with fixed bottom wind project installations. If the industry indeed matures, it is not inconceivable that floating platform wind could become less expensive than fixed bottom wind projects (at least on a levelized cost per kilowatt-hour basis) since the capacity factors of offshore wind projects may generally be superior to land-based wind projects.

Offshore Wind Viability

Floating platform wind technology has a likelihood of achieving commercial status within the next 10 years, if not sooner. It is therefore an appropriate technology to consider in the PSIP analyses. Nevertheless, there are a number of substantial risks that could delay or even make it impossible to develop offshore wind in Hawai‘i. Most of these risks are beyond the control of the Companies. If offshore wind is to be developed as a viable resource option in the future, planning by authorities and regulators at both the State and Federal levels needs to begin as soon as possible so that potential impediments can be identified and policy decisions can be made that will preserve offshore wind (as well as interisland transmission cables and hydrokinetic technologies) as options for the future.

Technology Review

Offshore floating platform wind technology has not yet been demonstrated at full scale. It is possible that floating platform wind will reach cost parity with fixed foundation wind platforms by the mid-2020s, however government support for full-scale demonstrations is required for this to be achieved. Full scale demonstrations are needed to bridge the gap between the pre-commercial status of floating platforms today and full commercial status where there are economies of scale across the industry to drive costs down to competitive levels, where private equity and debt investors will have the confidence to invest, developers will have the confidence to take development risk around projects employing this technology, and most importantly, utilities will consider the cost and technology risk acceptable to their ratepayers.

Platform size is a challenge to commercialization, since larger platform sizes accommodate larger turbines, which in turn leads to lower per-unit costs of installation. Installation procedures will also need to be developed to ensure efficient deployment of the platforms during the development phase. A set of standards for offshore floating platforms is under development. In the case of the semi-submersible platform technology being proposed for Hawai‘i, leading platform technology providers are currently working on perfecting the control systems that stabilize the platforms. Floating substation platforms also need to be perfected as only one floating substation has been deployed to date (in Japan).

Types of Floating Platform Technologies

The primarily function of the floating platform is to provide a stable platform that will allow the installed wind turbine to remain in a fixed position relative to the wind orientation so that maximum energy production is achieved. In open ocean environments, such as that found in Hawaiian waters, this is a substantial design requirement. There are three basic technology types under consideration for offshore floating platform wind, all derived from the offshore oil and gas industry:

Spar Buoy. The spar buoy platform maintains stability through use of a heavy cylindrical buoy that is submerged well below the top of the platform so that the center of gravity of the overall structure is very low, while the center of buoyancy is high (that is, at the top of the platform). The deep draft of the spar buoy, and the relative difficulty of constructing it, typically limits the spar buoy technology to shallower waters (that is, less than 100 meters). Advantages include simple design, and no active ballast system. Disadvantages include the need for construction at the site requiring heavy-lift cranes mounted on vessels, and the inability to tow the platform into port for repairs if needed.

Semi-Submersible. The semi-submersible platform floats on the surface of the ocean, with its structure partially submerged in the water. A dynamic control system maintains the stability and orientation of the platform using an active ballast system. The semi-submersible platform utilizes mooring lines attached to the ocean floor to anchor the platform in place, however the control system, not the mooring lines, provides the primary stability of the platform. Semi-submersible platforms can be utilized in deep waters (less than 1,000 meters). Advantages of semi-submersible structures include the ability to construct the platform in a port and then tow the completed platform into place. Disadvantages include the need for complex welded steel structures and a costly control system.

Tension Leg Platform. The tension leg platform is similar to the semi-submersible concept, however the stability of the platform is provided by the tensioned mooring lines themselves. This allows for a lighter structure, but it also increases the mechanical forces on the mooring lines and floor anchors. Failure of a tensioned mooring line can create substantial operational challenges. The major advantages of the tension leg platform technology are the ability to assemble the platform onshore, and the lack of a need for an active ballast system.

Figure H-11 shows an artist’s depiction of these three technology types.

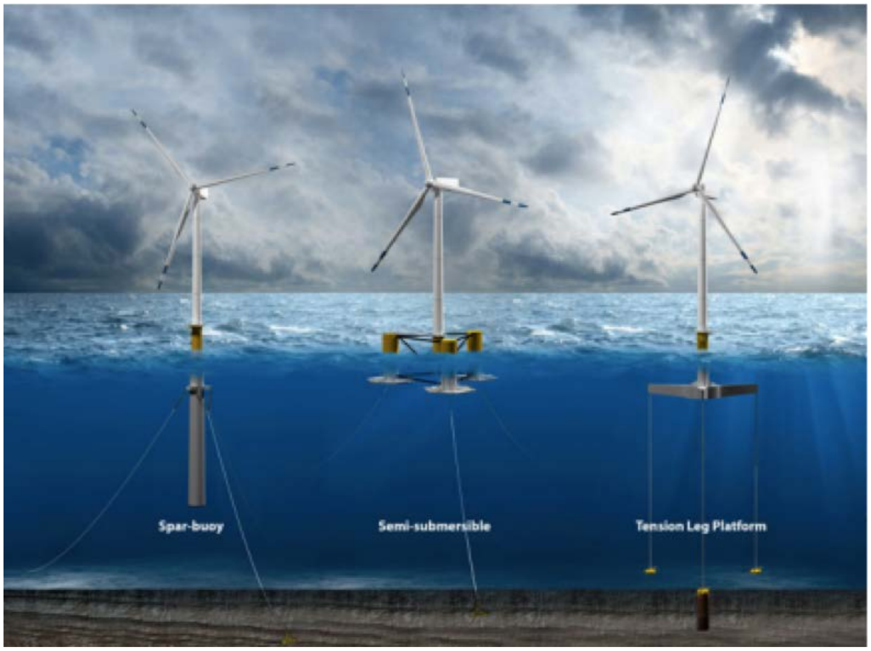

Figure H-11. Types of Offshore Wind Floating Platforms[9]

Two of the commercial proposals for offshore floating platform wind in Hawaiian waters indicate that they plan to utilize semi-submersible platforms, in particular the WindFloat technology being developed by Principle Power (Figure H-12). According to Principle Power’s website, to date, a single WindFloat installation has actually been achieved. That prototype installation utilizes a 2 MW wind turbine, and was installed in 2011 approximately 5 kilometers off the coast of Aguçadoura, Portugal. The platform was assembled and commissioned onshore before being towed 400 kilometers along the Portuguese coast from its assembly facility.[10]

The WindFloat product is one of the most technologically advanced floating platform technologies, although it has yet to achieve commercial status. Further, semi-submersible technology, in particular the WindFloat product, is suited for the extremely deep water installation environment proposed in Hawai‘i.

A European-based developer has indicated privately to the Companies that it also intends to propose an offshore wind project in Hawai‘i utilizing the spar buoy technology. No details of that proposal have yet been made public.

[9] Illustration by Josh Bauer, National Renewable Energy Laboratory, obtained from *Floating Offshore Wind in Hawai‘i: Potential for Jobs and Economic Impacts from Two Future Scenarios* Tony Jimenez, David Keyser, and Suzanne Tegen National Renewable Energy Laboratory, April 2016. Prepared for BOEM, OCS Study BOEM 2016-032.

[10] See: http://www.principlepowerinc.com/

Figure H-12. WindFloat Prototype[11]

Platform Anchoring Systems

Semi-submersible floating platforms utilize a control system to maintain stability. The platform itself is anchored in place with a catenary system that is typically made up of steel chains whose weight holds the platform in place. Principle Power had planned to utilize three anchors per platform in an Oregon project. The lower section of the chain rests on the seabed and is secured to the ocean floor. In sandy and clay seabed conditions, the anchoring system utilizes drag-embedded anchors, which are completely recoverable during decommissioning. The drag-embedded anchoring system is based on existing technology used in oil and gas platforms. The system is relatively simple to install since it does not require permanent pilings to fasten to the seafloor. This also makes it simple to decommission. The main drawback is the larger seafloor footprint required relative to driven pile anchors. The typical radius catenary mooring footprint radius is about 600 meters.[12] If the seabed conditions in Hawai'i are not conducive to drag anchors (that is, rather than sand or clay, the bottom is rock), then driven pile type anchors will be required. In general, the type of anchoring system is site specific.

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[11] Source: Alpha Wind Energy, Hawai'i Offshore Wind Energy Lease Application O'ahu Northwest (Public Version), January 2015. Cover.

[12] Figure 3.1.13, p 87. *Floating Offshore Wind: Market & Technology Review*. June 2015. The Carbon Trust.

Offshore Wind Turbines

The largest installed offshore wind turbine is currently 6 MW; however, 8 MW turbines are slated for commercial introduction in the near future. Typically, the increase in the size of wind turbines is an evolution of previous designs, rather than development of a totally new concept.[13] Thus, it is likely that by the time a project is ready for development in Hawai'i, larger turbine sizes may become available. Larger turbines mean fewer platforms and greater energy production per platform.

Submarine Cabling Systems

Submarine cabling systems are based on mature technologies. Wind facilities require a web of undersea cables, which have a significant instance of failure and resulting insurance claims within the offshore wind industry.[14] Typically, the installation of an undersea cable is a specialized undertaking that requires an experienced installer with special equipment. There are only a handful of such specialized installers in the world. Thus, during the construction phase, care must be taken to install and test submarine cables.

Technology Readiness

Energy technologies can be rated for their readiness in the marketplace through a Technology Readiness Level (TRL) system. The TRL levels, as defined by the U.S. Department of Energy, are described in Table H-7.

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[13] http://www.renewableenergyworld.com/articles/print/volume-19/issue-9/features/wind0/understanding-risk-for-new-wind-technology-in-new-wind-markets.html.

[14] *Ibid.*

Relative Level of Technology Development	TRL	TRL Description
System Operations	TRL 9	Deployment. Technology in final form and operated over full range of operating mission conditions.
System Commissioning	TRL 8	End of system development. Technology proven to work in its final form and under expected conditions.
	TRL 7	Full-scale prototype demonstrated in a relevant environment.
Technology Demonstration	TRL 6	Engineering-scale or pilot-scale models or prototypes tested in a relevant environment.
Technology Development	TRL 5	Laboratory scale, similar to a system validation in a relevant environment. Laboratory system tested in a simulated environment. System configuration similar to final application in all respects.
	TRL 4	Component or system validated in a laboratory environment. Basic technological components integrated to establish that the separate elements will work together in a laboratory environment.
Research to Prove Feasibility	TRL 3	Analytical and experimental critical function or characteristic proof of concept. Active research and development is initiated. Physical validation of analytical predictions of separate elements of the technology.
	TRL 2	Technology concept or its application formulated. Invent practical applications of the technology. Applications are speculative.
Basic Technology Research	TRL 1	Basic technology principles observed and reported. Scientific research beings to be translated into applied research and development.

Table H-7. Technology Readiness Levels[15]

With the deployment in 2011 and extensive testing of the 2 MW WindFloat project over a period of years in Portugal, the WindFloat technology has achieved deployment of an "engineering scale prototype in a relevant environment" and thus qualifies as a TRL Level 6.

Principal Power had been planning to install a full-scale prototype off the coast of Oregon in 2017.[16] However, Principle Power withdrew its application for a lease through BOEM, who states that it is "no longer processing this application" for the Oregon project.[17]

In the meantime, Principle Power continues to pursue a full-scale project off the Portuguese coast. The WindFloat Atlantic (WFA) project is planned to be operational in 2018 and "will consist of three or four wind turbines on floating foundations" with a total capacity of 25 MW. The WFA project is supported by the European Commission through the NER 300 program, the Portuguese Government through the Portuguese Carbon

[15] *Technology Readiness Assessment Guide;* U.S. Department of Energy, DOE G 413.3-4A, September 15, 2011. Adapted from Table 1: Technology Readiness Levels, pages 9–10.

[16] http://windfloatpacific.com/faqs/.

[17] http://www.boem.gov/windfloatpacific/.

Fund, and the InnovFin program by the European Investment Bank. The stated aim of the project is "to demonstrate the economic potential and reliability of this technology, advancing it further in the path towards commercialization."[18] In other words, successful deployment of the WFA project, or another similarly scaled project, would constitute a full-scale prototype demonstrated in a relevant environment and thereby qualify as a TRL Level 7. Successful operation of this pilot project over a period of one to two years would qualify the technology as TRL Level 8. Thus, this technology could reach *technical* maturity in the early 2020s.

Commercial Readiness

Technology readiness should not be confused with commercial readiness. The Australian Renewable Energy Agency (ARENA) developed a Commercial Readiness Index (CRI) in February 2014. [19] The CRI scale assesses technology readiness against a number of practical indicators including the financial proposition, regulatory environment, industry supply chain and skills, market opportunities, and vendor maturity (that is, established companies with strong credit ratings).

CRI Level	Commercial Readiness	Definition
6	Bankable grade asset class	Financial investors view the technology risk as low enough to provide long-term financing (that is, bankable). Known standards and performance expectations are in place, along with appropriate warranties. Vendor capabilities (including both technology vendors and EPC vendors), pricing, and other market forces drive market uptake ("demand pull").
5	Market competition driving widespread deployment	Emerging competition across all areas of the supply chain with commoditization of key components and financial products occurring.
4	Multiple commercial applications	Full-scale technology demonstrated in an industrial (not R&D) environment for a defined period of time. May still require subsidies. Publicly verifiable data on technical and financial performance. Interest from debt and equity sources, although still requiring government support. Regulatory challenges being addressed in multiple jurisdictions.
3	Commercial scale-up	Deployment of full-scale technology prototype driven by specific policy. The commercial proposition is driven by technology proponents and market segment participants (a "supply push"). Publicly discoverable data is driving interest from finance and regulatory sectors, but financing products not yet widely available. Continues to rely on subsidies.
2	Commercial trial	Small scale, first of a kind project funded by equity 100% at risk and/or government support. Commercial proposition backed by evidence of verifiable performance data typically not available to the public. Proves the essential elements of the technology perform as designed.
1	Hypothetical commercial proposition	Technically ready, but commercially untested and unproven. The commercial proposition is driven by technology advocates with little or no evidence of verifiable technical data to substantiate claims.
0	Purely hypothetical	Not technically ready. No testing at scale. No technical data.

Table H-8. Commercial Readiness Levels

[18] http://nawindpower.com/principle-powers-technology-inspires-consortium-to-build-floating-wind-farm-off-of-portugal

[19] Based on *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. ©Commonwealth of Australia, February 2014. Table 1, page 5.

Based on Principle Power's success to date, the WindFloat could be considered to have achieved CRI Level 2—deploying an engineering scale prototype, but not yet demonstrating the technology at a full commercial scale. With the planned full-scale prototype planned for 2017, the WindFloat would achieve CRI Level 3. However, CRI Level 3 is still far below CRI Level 6, where the technology is considered bankable. Using the capital cost estimates of approximately $4,000 per kilowatt, 800 MW of offshore floating platform wind would require $3.2 Billion in capital. Developers with proposals for Hawaiʻi that utilize the WindFloat technology would likely face a financing environment where few, if any, debt and equity providers would provide this massive amount of capital.

Note that the 25 MW WFA project proposed for Portugal will rely largely on government subsidies for financing. Thus, while the WindFloat technology could reach *technical* maturity in the next three to five years, it could take substantially longer for the sources of commercial financing to materialize to support development in Hawaiʻi of the hundreds of MW of offshore wind proposed by developers.

Developer Interest

Currently two developers—Alpha Wind Energy and Progression Energy—are known to be proposing offshore wind facilities in the waters around Oʻahu (based on the unsolicited lease proposals submitted to BOEM).[20] At the BOEM Task Force Meeting in Honolulu on May 16, 2016, BOEM representatives stated that they are aware of a third developer who may submit a lease application as part of a competitive leasing process for offshore wind blocks near Oʻahu.

Alpha Wind Energy

Alpha Wind Energy (dba AW Hawaiʻi Wind LLC) proposes to develop 400 MW of offshore wind near Oʻahu "with the option to expand further." Alpha has submitted lease proposals to BOEM for two different sites near Oʻahu.

Alpha states that the majority of the main components for the wind facility will be produced or assembled in Hawaiʻi creating 100 permanent jobs. Alpha states in its BOEM Lease Application that it has consulted with the State Harbors Division and has confirmed that suitable harbors are available for "manufacturing, servicing, and maintenance" of the proposed wind project. A port area of 100,000 m^2 (24.7 acres) is required. Alpha also states that "most main components will be produced elsewhere and shipped to Hawaiʻi for assembly." The assembly is to be accomplished in dry docks and

[20] The unsolicited lease proposals are available for download at http://www.boem.gov/Hawaii/.

the fully commissioned turbines will be towed and connected to pre-installed anchors and electrical cables. 8 MW turbines are envisioned.

Alpha plans to initially construct an offshore floating substation that will be fed by a collection grid energized at 33–69 kV. The substation will feed power via a single power cable to O‘ahu energized at either 69 kV or 138 kV. Alpha proposes to interconnect the wind facility to the O‘ahu grid at one or more of the following points: Kahe Power Plant, Barbers Point industrial area, or Wahiawa substation. Alpha states that the project could be expanded in the future with interconnections via a “loop connection” and possibly to Maui, Moloka‘i, and Lana‘i via undersea cables.

In its BOEM Lease Application, Alpha proposes to begin construction in mid-2018 and energize the first turbine to begin delivering power by early 2020. Alpha recognizes in its BOEM Lease Application that this is a “very aggressive” schedule that will “take every effort at all levels” to meet.

Progression Energy

Progression Energy proposes to construct an offshore 400 MW wind facility southeast of O‘ahu. The project will consist of between 40 and 50 floating platforms sited in waters with an average depth of 2,700 feet. Each platform will have an 8 MW to 10 MW turbine. Progression plans to utilize the “WindFloat” semi-submersible floating foundation from Principal Power.

The project will be built in two, 200 MW phases. Progression’s offshore wind facility will include a collection system of power cables energized at 34.5 kV. Power from the individual turbines will be sent via the collection system to a floating substation centrally located within the wind turbine arrays. Each 200 MW phase of the project will utilize two 105 MVA 34.5/138 kV transformers. Each phase of the project will be interconnected to the O‘ahu grid via 138 kV undersea cables. Two separate interconnections, one for each phase of the project, are planned.

Progression intends to utilize a local supply chain for professional services, harbor facilities, vessels, and components involved in the “fabrication and/or assembly, deployment and operation and maintenance” of its project. Construction of the project will require a construction port with laydown space that will serve as the staging area for assembly of the WindFloat platforms and wind turbines. The port facilities must also have sufficient berthing space for loading and unloading.

Progression states that it will include local sourcing provisions in its larger contracts. Progression plans to offer training, educational, and research opportunities, as well as a community benefits program.

To create a "highest likelihood for success," Progression states that it has met with over 100 stakeholders to educate the community about the project, and select an offshore site that will be acceptable across a number of different interests, including the U.S. Department of Defense.

Progression proposes to begin construction of the first 200 MW phase of the project in late 2020 and begin commercial operation in early 2022. The second 200 MW phase of the project would begin construction in late 2021 and would achieve commercial operation in early 2023.

Alpha Wind and Progression Energy Unsolicited Lease Proposals

Figure H-13 depicts the locations of the Alpha Wind Energy (AWH) and Progression Energy lease proposals as submitted to BOEM.

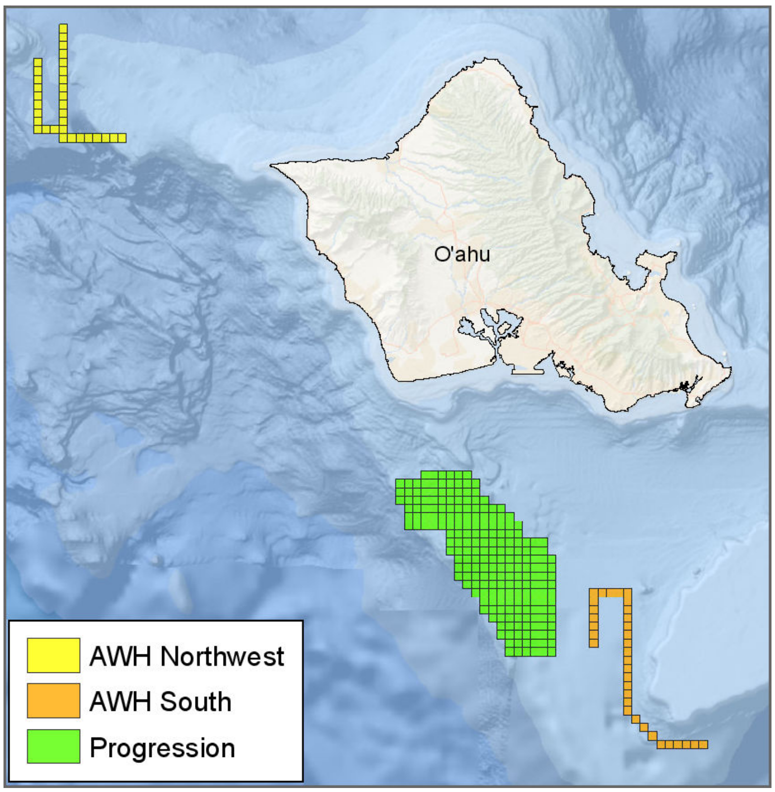

Figure H-13. O‘ahu Unsolicited Lease Proposals Received by BOEM

Capital Cost Assessment

Because floating platform wind technology is not yet a fully mature technology, there is considerable uncertainty as to the future capital cost of commercial offshore floating platform wind projects. There are several competing technical concepts, the most advanced of which is the semi-submersible platform concept. Principle Power's WindFloat design is one of the most advanced concepts. However, additional deployments of this technology are needed to perfect the technology and assess the commercial cost in the future. Project costs will also be influenced by site conditions, availability and proximity of port infrastructure, supply chain capabilities, and the local permitting environment.

Developer Capital Cost Estimates

The two known interested developers of offshore wind have made public statements regarding the cost of offshore wind. Progression Energy claims that it can develop a 400 MW project for $1.8 Billion or about $4,500 per kilowatt.[21] Alpha Wind Energy says it can develop a 408 MW project for $1.9 Billion or about $4,657 per kilowatt.[22] Both developers say that they can deliver a completed project in the 2019–2022 timeframe.

The Carbon Trust Capital Cost Estimates

The Carbon Trust report for the Scottish Government did not provide a year-by-year projection of the capital cost of offshore floating platform wind; however, it did provide several data points regarding the cost at various stages of technological development. Table H-9 shows the Carbon Trust estimates of capital cost (in U.S. $/KW, converted from € at an exchange rate of $1.12 / €1.00).

Technological Maturity	Capital Cost in U.S. $/KW
Prototype	$5,824
Pre-Commercial	$4,704
Commercial	$3,024

Table H-9. Offshore Floating Platform Wind Capital Cost Estimates[23]

The Carbon Trust reported these figures with a strong caveat:

[21] http://phys.org/news/2016-05-companies-deep-water-farms-hawaii-shores.html.

[22] http://www.governorswindenergycoalition.org/?p=12234.

[23] *Floating Offshore Wind: Market and Technology Review*, Prepared for the Scottish Government, June 2015. Table 3.5.2, page 125.

> The uncertainty associated with the data is largely associated with the nascent state of the technology. Very few floating wind devices have been deployed at full-scale and those which have consist of single prototype demonstrations, which have not had to contend with the additional challenges encountered in commercial-scale deployments, such as high voltage electrical transmission, wake effects, batch fabrication and installation procedures, O&M, logistics, etc.
>
> Furthermore, Carbon Trust experience suggests that the cost of innovative technologies can increase from initial conception to demonstration phase, before falling as the design is optimized and deployment increases. Given that most of the concepts assessed are in the early stages of development and may be nearer the beginning of this cost curve, it is possible that the cost estimates underestimate the full costs of deploying the technology.[24]

The Carbon Trust report was published in 2015, so presumably the figures stated above are 2015 cost levels. Notwithstanding the reference year, The Carbon Trust capital cost estimates and their qualifications on such estimates are not a strong basis for projecting the capital cost of floating platform wind projects for use in a utility planning study.

NREL Capital Cost Estimates

NREL provides capital cost projections for various power generating technologies in its Annual Technology Baseline (ATB). NREL finalized the 2016 ATB in August 2016 and included several offshore wind technologies including floating platform technologies. The reference plant was described by NREL as approximately 500 MW in size, deployed on floating platforms in deep water (61–700 meters).

The plant envelope includes:[25]

- Wind turbine
- Turbine installation
- Substructure supply and installation site preparation
- Port and staging area support for delivery, storage, and handling
- Underground utilities installation
- Electrical infrastructure such as transformers, switchgear, and electrical system connecting turbines to each other and to a control center
- Project indirect costs including engineering, distributable labor, and materials
- Construction management start-up and commissioning
- Contractor overhead costs, fees, and profit

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[24] *Ibid.*, page 124. Edited to remove references to figures not included here.

[25] *ATB Summary Presentation – 2016 Final*, pp 23-30. Available at http://www.nrel.gov/docs/fy16osti/66944.pdf.

- Financial costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, and property taxes during construction
- Onsite electrical equipment (for example, a switchyard)
- A nominal-distance spur line

NREL's ATB Summary presentation also states that "… floating technology is not yet commercial and no market comparison data exists."[26] NREL provided a low, mid, and high range of capital cost projections. NREL states that the projections depend on the degree of adoption. The degree to which the low, mid, or high ranges will come to fruition are based on how the following trends play out over time:

- Continued scaling to larger MW turbines with greater efficiencies.
- Competition for primary components and services necessary to construct projects (for example, turbines, support structure, and installation).
- Economy of scale and productivity improvements in the production and installation of sub-structures and components.
- Improved plant siting and operation to reduce plant level energy losses, thus increasing its capacity factor.
- Efficient operation and maintenance procedures combined with more reliable components to reduce fixed O&M costs.
- Adoption and innovation in control systems, materials, and design.

Before the release of the 2016 ATB and during the development of the planning input assumptions for the April 2016 updated PSIP, the use of the 2015 version of the ATB was called into question by one of the known Hawai‘i offshore wind project developers. This developer stated that an internal team at NREL with expertise in offshore wind had developed offshore wind capital costs that were different (and lower) than the 2015 ATB projections. This led to several dialogues with NREL and its offshore wind experts. Two salient data points were obtained from these dialogues:

- The deep water, floating platform, low-case capital cost "trajectory" reaches approximately $5,300 per kilowatt in 2020 according to Aaron Smith of NREL.[27]
- The earliest date for a commercial offshore floating platform wind project is likely 10 years away, "maybe" as early as 2025. The technology will likely become commercial but "lots" of technical hurdles remain.[28]

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[26] *Ibid.*

[27] Wesley Cole of NREL email to HDBaker & Company, January 15, 2016. This number was qualified as lacking full review and was characterized as "preliminary".

[28] Lisa Giang of Hawaiian Electric, Hugh Baker of HDBaker & Company telephone call with Walt Musial of NREL on April 22, 2016.

Capital Cost Recommendations for 2016 PSIP

Because the technology has not reached commercial status, there is considerable uncertainty as to the actual capital costs for offshore floating platform wind. In early 2016, after conversations with NREL and its offshore wind experts, the Companies decided to use the "unofficial" $5,300 per kilowatt capital cost estimate for 2020 as the basis for the PSIP assumptions. This amount was adjusted by a factor of 1.138 to reflect the Hawai'i's higher installation cost,[29] for a total nominal capital cost of $6,031 in 2020.

Figure H-14 graphs these various capital cost values. For a consistent comparison, the PSIP capital cost assumption has removed the Hawai'i location factor. The PSIP capital cost numbers have been adjusted to 2014 dollars (to be consistent with the NREL ATB). These PSIP capital cost assumptions are below the 2016 NREL ATB (indicating a more pessimistic view of capital cost declines by NREL) and are slightly higher than the two developer estimates in the early years. The Carbon Trust estimate for fully commercialized offshore wind is well below all of the other estimates, reflecting The Carbon Trust's view of the capital cost when there is a robust market for offshore wind. The PSIP assumption for offshore wind capital cost approaches The Carbon Trust commercial value towards the end of the projection horizon.

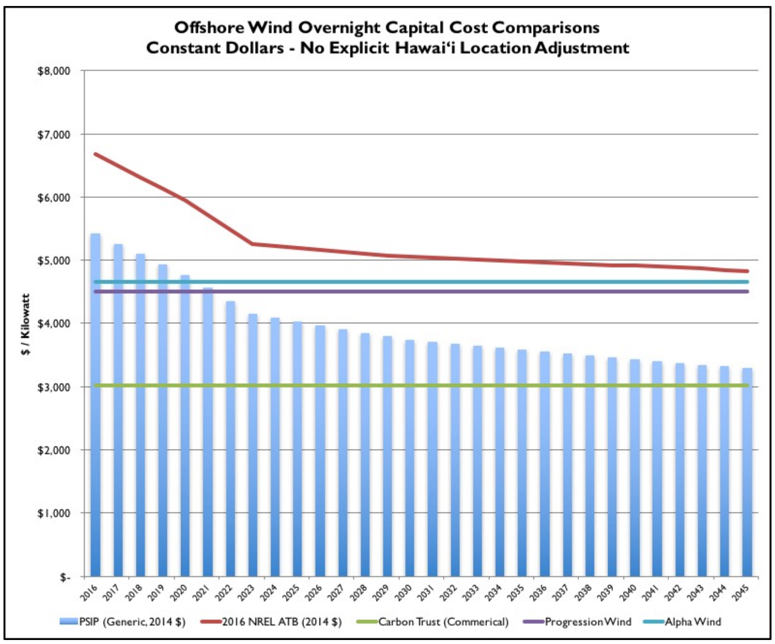

Figure H-14. Offshore Floating Platform Wind Capital Cost Projections and Comparisons

[29] The source of this adjustment factor is the U.S. Energy Information Administration report *Updated Capital Cost Estimates for Utility Scale Electricity*, April 2013.

Based on this research, the capital cost projection prepared for the 2016 PSIP update appears to be a reasonable projection given the considerable uncertainty around the technological maturation and commercialization time lines associated with this technology. The Companies plan to continue monitoring developments in offshore floating platform wind technology as the technology matures, particularly as it relates to capital cost improvements.

Project Development

BOEM is the lead agency for siting offshore wind facilities. BOEM has authority over energy projects in federal waters. Historically, BOEM's activities have primarily related to offshore oil and gas exploration and production, but more recently, there has been interest in developing offshore wind energy projects, particularly along the U.S. eastern seaboard. Thus far, BOEM has issued 11 leases for offshore wind energy projects located in Rhode Island, New York, and Virginia. BOEM has four unsolicited lease proposals in federal waters in the Pacific Ocean, including three in Hawai‘i and one in California.

BOEM views its role as defining a consistent permitting process for offshore wind in the United States. BOEM seeks to balance the needs of all ocean users and is currently engaged in an extensive stakeholder process. BOEM stresses that, in Hawai‘i, it is in the middle of a process and the outcome is far from certain.[30]

Potential Offshore Wind Lease Areas in Hawai‘i

For Hawai‘i, BOEM has identified a number of potential areas ("Call Areas") for offshore wind development and has defined certain potential lease blocks.[31] Areas thought to be suitable by BOEM for offshore wind development in Hawai‘i were determined through a process of inclusions and exclusions around the following criteria:

- The proposed lease areas must be within BOEM authority.
- The proposed lease areas must have acceptable wind speeds.
- Water depths must be less than 1,100 meters (BOEM's opinion of the maximum reasonable depth for offshore wind feasibility).
- The lease areas must not include any areas where bottom dwelling fish are protected.
- The lease areas must be outside whale sanctuaries.
- Areas with high vessel traffic (as determined by BOEM's analysis of vessel traffic patterns) must be excluded.

[30] Abigail Ross-Hopper, Director of BOEM, statement at the May 16, 2016 BOEM Hawai‘i Offshore Wind Task Force meeting in Honolulu, Hawai‘i.

[31] A standard OCS block is 4800 meters square containing 2304 hectares (5693.3 acres) or about 9 square statute miles.

Based on this criteria, BOEM identified two "sub-areas" within the O'ahu Call Area:

1. O'ahu North, located approximately 7–24 nautical miles west of Kaena Point, O'ahu, consists of 17 full and 20 partial Outer Continental Shelf (OCS) blocks.
2. O'ahu South, located approximately 7–35 nautical miles south of Barbers Point, O'ahu, consists of 44 full and 32 partial OCS blocks.

Figure H-15 shows a map of these O'ahu Call Areas graphed on a 2.5 by 2.5 nautical mile grid.

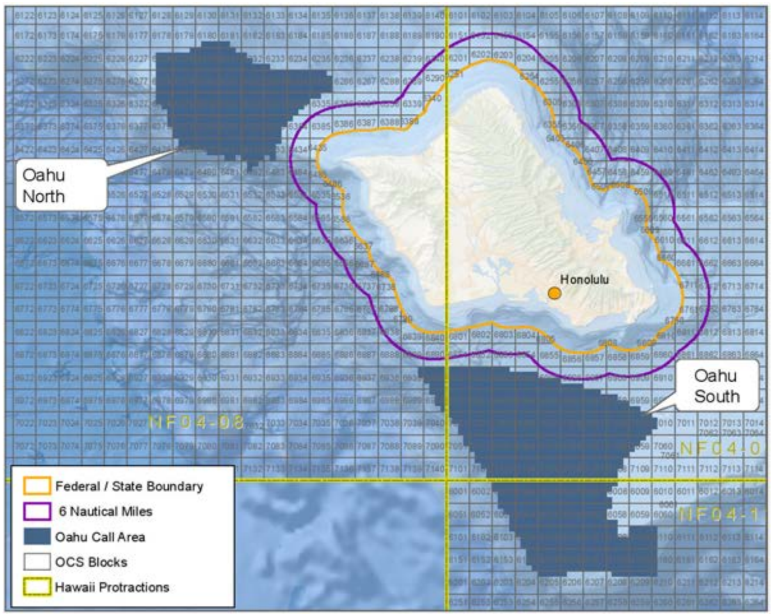

Figure H-15. BOEM Designated O'ahu Call Areas

At a May 16, 2016 Task Force meeting, BOEM stated that the vessel traffic area exclusions had so far *not* taken into account U.S. Navy Pacific Fleet operations. A representative of the Pacific Fleet indicated that the Navy would like to provide classified information to BOEM to ensure that the Navy's operations are considered. On May 25, 2016, the Navy published a map showing zones that were "Incompatible with Department of Navy Operational and Readiness Activities."

Figure H-16 shows that a large portion of the BOEM Call Areas fall into this incompatible zone. In addition, virtually all of the blocks that Alpha Wind and Progression Energy propose to develop are located within these incompatible zones. This should *not* be construed to preclude development of offshore wind around O'ahu. BOEM has contracted with NREL to develop more detailed information to assist BOEM and the U.S. Navy to further investigate how offshore wind can coexist with the Navy's operations and training missions.[32] As of early September 2016, this work is underway.

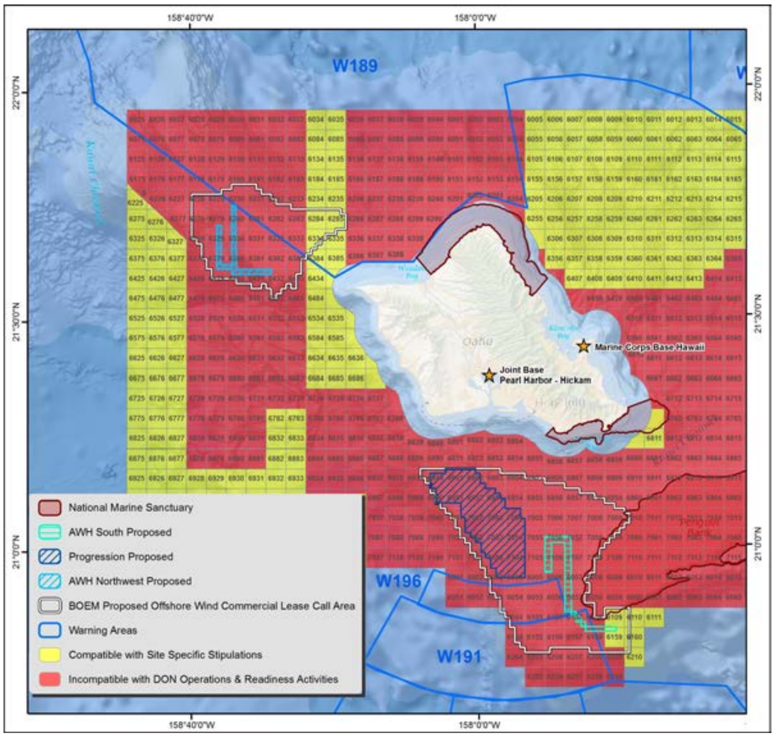

Figure H-16. Navy Incompatible O'ahu Call Areas and Unsolicited Lease Proposals[33]

BOEM Lease Process

On June 24, 2016, BOEM issued a Call for Information and Nominations (Call), inviting "… the submission of information and nominations from parties interested in obtaining one or more commercial wind energy leases that would allow lessees to propose the construction of wind energy projects on the Outer Continental Shelf offshore the island of O'ahu, Hawai'i."[34] This is the first step in the BOEM leasing process.

[32] Telephone conversation with Walt Musial and Robi Robinchaud of National Renewable Energy Laboratory. September 8, 2016.

[33] http://greenfleet.dodlive.mil/rsc/department-of-the-navy-hawaii-offshore-wind-compatibility/.

[34] *Federal Register*, Vol. 81, No. 122, Friday, June 24, 2016, Notices, p 41335.

BOEM determines if competitive interest exists for blocks within the Call Area. If so, BOEM then moves to a competitive auction process (with appropriate public notices in advance of the "Sale Notice"). If there is no competitive interest, then BOEM may negotiate a lease directly with a project developer. For example, in the case of the unsolicited lease proposals submitted to BOEM so far, unless there is an interest from other parties in leasing the same blocks, BOEM may choose to negotiate directly with these two project developers.

Upon award of a lease, the developer has one year to develop a Site Assessment Plan (SAP). BOEM then conducts environmental and technical reviews of the SAP. BOEM can approve, approve with modifications, or disapprove the SAP.

If the SAP is approved (or modified to meet BOEM's concerns), the developer then begins additional site assessment studies, including installation of meteorological towers, buoys, or both. The developer has five years from approval of the SAP to submit a Construction and Operations Plan (COP). The SAP and COP form the basis for the detailed environmental (including the EIS) and technical reviews. When the COP is approved (and all other required permits and approvals are obtained), the developer can begin construction of the project.

At the May 16, 2016 BOEM Task Force meeting, representatives of BOEM stated that the entire process could take 5 to 10 years to complete, which would support a construction start date no earlier than 2021.

Environmental and Permitting

Besides obtaining a lease from BOEM and complying with the lease conditions, a variety of permits and approvals will be required to construct and operate an offshore wind project. The interested agencies include, but are not limited to:[35]

- U.S. Navy (including the Pacific Fleet and Marine Corps)
- U.S. Coast Guard
- U.S. Army Corps of Engineers
- U.S. Department of Commerce, National Oceanic ,and Atmospheric Administration
- Hawai‘i Humpback Whale National Marine Sanctuary
- National Ocean Service
- National Marine Fisheries
- U.S. Department of Interior

[35] This list is based on information from BOEM, but is not intended to be a comprehensive list of all of the permitting agencies and public consultations that would be involved in the development of an offshore wind project in Hawaiian waters.

- Fish and Wildlife Service
- National Park Service
- Federal Aviation Administration
- Environmental Protection Agency
- Council on Environmental Quality
- Advisory Council on Historic Preservation
- State of Hawai‘i Department of Land and Natural Resources
- State of Hawai‘i Department of Transportation Harbors Division
- State of Hawai‘i Department of Business, Economic Development, and Tourism
- State of Hawai‘i Office of Hawaiian Affairs

Other stakeholders with potential interests in an offshore wind project in Hawai‘i may include:

- Commercial fishing interests
- Commercial marine shipping
- Commercial ocean tour businesses
- Recreational ocean users
- Local communities impacted by any visual impacts, cable landings, new on-land infrastructure, etc.
- Non-governmental organizations.

An offshore wind project constructed to serve electric loads on O‘ahu will need to execute a Power Purchase Agreement with the Companies. Any PPA will be subject to successful negotiations, including price, schedule, and technical considerations. The PPA must be approved by the Hawai‘i Public Utilities Commission. Such an approval process is likely to be a litigated proceeding, extending the time until construction could possibly begin.

While obtaining the approvals for offshore wind projects requires a process similar to other energy development projects, the installation of floating platforms in 700–1,000 meter deep waters as proposed in Hawai‘i, with high voltage subsea electrical interconnections to land, has never been done before anywhere in the world. Therefore, there are potential unknowns about the permitting process and community acceptance that pose development risks. It is therefore likely that any successful approval process will be lengthy, complicated, and potentially contentious.

National Environmental Policy Act (NEPA)

The National Environmental Policy Act (NEPA) requires Federal agencies to consider environmental factors when making decisions. For an offshore wind project in Hawai'i, BOEM is the designated Federal lead agency for ensuring that NEPA requirements are met.

As the lead agency, it is BOEM's responsibility to:

- Involve affected and interested members of the public.
- Coordinate the environmental review by other affected Federal agencies.
- Evaluate relevant environmental factors and potential mitigation of environmental impacts.
- Document the environmental affects by preparing an Environmental Impact Statement (EIS).

To evaluate potential leases, BOEM will do two NEPA reviews. The first NEPA review will occur before to the award of leases. This review will analyze resource and site characteristic assessments to inform BOEM about areas acceptable to be leased.

The second NEPA review will take place after the award of the leases and the developer's submission to BOEM of a SAP and Environmental Assessment. During this period, the develop will create a site COP. Before starting construction, another NEPA analysis, most certainly an EIS, will need to be completed. Typically the EIS is scoped to include all of the factors that must be addressed under NEPA, as well as factors that may be specific to the State (for example, the Hawai'i Environmental Policy Act)[36] or locale where the project is planned. That avoids duplication of efforts while meeting multiple jurisdictional requirements.

[36] Some NEPA and HEPA requirements overlap; important differences exist in others. Thus, it is generally more efficient to prepare an EIS that addresses the requirements of both.

In September 2015, the U.S. Department of Energy finalized a Programmatic Environmental Impact Statement (PEIS) that analyzed "… the potential environmental impacts, and best management practices that could minimize or prevent those potential environmental impacts, associated with 31 clean energy technologies and activities…"[37]

The Hawai'i Clean Energy PEIS indicated that the State of Hawai'i has particular interest in four environmental resource areas:

- Biological resources
- Land and submerged land use
- Cultural and historic resources
- Scenic and visual resources

BOEM has already begun to address some of these issues through a series of studies, some completed and some ongoing.

Construction

Successful construction of offshore floating platform wind projects depends on the availability of port facilities for assembly, vessels for transporting assembled units and servicing installed units, and integrating and interconnecting the units to the onshore electric power grid.

Port Facility Requirements

The U.S. wind industry is still in its infancy. Offshore wind energy projects require specialized equipment, services, and labor expertise for construction and servicing, much of which does not yet exist. These capabilities are likely to develop based on lessons learned from the European offshore wind industry and by leveraging existing marine industries.

[37] Hawai'i Clean Energy Final Programmatic Environmental Impact Statement Summary, U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Office of Energy Efficiency and Renewable Energy, DOE/EIS-0459, September 2015.

Offshore wind construction and operation require specialize port facilities that can host fabrication and assembly of platform and turbines, staging for and the installation of the platforms and turbines at the project site, and ongoing operation and maintenance activities. BOEM recently commissioned a study that addresses the status and needs of port facilities to support an offshore wind and hydrokinetic energy industry in the Pacific Region of the United States, including Hawai'i.[38] This report identified the following three major functions that one or more ports must provide to support offshore wind.

Quick Reaction Port: This includes pre-installation surveys and transfer of construction and maintenance crews to the wind platform site.

Fabrication and Construction Port: This function essentially fulfills the need for a transportation hub for all of the components (wind turbines, platforms, cables, and related components); for fabrication of device components; and for construction, staging, and pre-assembly of device components.

Assembly Port: This function provides the ability to assemble the floating platforms and turbines in port for towing to the project site.

In its BOEM Lease Application, Progression Energy states that the minimum requirements for a port that can support its project include:

- Access channel depth of at least 10 meters (32 feet).
- Minimum berthing frontage of 250–300 meters (820–984 feet).
- Quayside bearing capacity of approximately 9,071 kilograms/m^2 (10 tons).
- 20–30 acres of available staging areas and reliable access to intermodal transfer facilities.
- U.S. Government support offices in the vicinity.

Progression did not identify any specific available port facilities in Hawai'i that could meet these minimum requirements.

The BOEM 2016-034 report provides an extensive assessment of Hawai'i port facilities and their suitability to support floating platform wind development and operation. Based on its assessment of the port facilities, the BOEM 2016-034 report identified "potential gaps" related to port facilities in Hawai'i for supporting an offshore wind industry in the State.

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[38] *Determining the Infrastructure Needs to Support Offshore Floating Wind and Marine Hydrokinetic Facilities on the Pacific West Coast and Hawai'i.* (OCS Study, BOEM 2016-011, March 3, 2016.

These gaps include:

- Additional upland area with marine access would be needed to fully support fabrication requirements.
- Turbine components will likely be imported because of the lack of availability of land for fabrication and construction of turbines.
- The berth-specific bearing capacity in specific ports is unknown at this time.
- Assembly of the semi-submersible floating platforms will require major land redevelopment in any of the Hawai'i port areas.
- There is limited redundancy among potential port locations.
- Harbor depths preclude assembly of the offshore wind spar buoys (assuming a spar buoy platform design) with existing technology.

In Hawai'i, the ports of interest to the offshore wind industry are managed by the State of Hawai'i Department of Transportation, Harbors Division. The most likely Hawai'i port for support of an offshore wind industry in Hawai'i is Kalaeloa Barbers Point.[39] The Harbors Division has indicated the following:[40]

- The current port facilities at Kalaeloa Barbers Point are congested with multiple competing uses for routine importation of commodities such as lumber, cement, and asphalt.
- There is a plan to add berthing space to relieve this congestion, but this plan is in response to additional demand from either existing users, or new users other than the offshore wind industry. The Harbors Division completed a Master Plan for 2040 for Kalaeloa Barbers Point Harbor in 2015. The Master Plan process, however, did not receive any input from offshore wind interests, and therefore it did not consider the possibility of offshore wind assembly or fabrication.
- Improvements of ports in the State of Hawai'i usually happen after an EIS has been prepared. Revenue bonds are used to finance the improvements, however they cannot be issued for funding improvements that would only benefit a single user.
- There are inland areas around the Kalaeloa port that could be expanded. However, there is strong demand for this space from interests that would consider long-term leases (for example, 20 plus years). In contrast, offshore wind developers would only commit to much shorter term (for example, three years) leases. This sets up a policy decision by the State for deciding among competing uses of the limited area in existing ports, even if such ports are expanded.

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[39] Telephone conversation with Dean Watase, Senior Planner, Department of Transportation, Harbors Division.
[40] *Ibid.*

- Due to the proximity to airports, assembly and erection of floating wind platforms, with towers and turbines as tall as 700 feet, would violate current FAA height restrictions at both Kalaeloa Barbers Point and Honolulu harbors.

As such, there are significant challenges for any developer wishing to utilize the few, already constrained ports in the State of Hawai‘i for fabricating and assembling floating platform wind turbines. While these challenges might be overcome, significant resources will be required (time and money) and political decisions will have to be made. In particular, the time it will take to complete these modifications calls into question the ability to meet the aggressive schedules proposed by Alpha and Progression.

Vessels

A variety of vessels will be required to construct and service offshore wind facilities.

Anchor handling tugs and service vessels, Offshore wind service vessels, crew transfer vessels, service vessels are typically not found on the west coast or in Hawai‘i and would probably need to be purpose built to meet the high swell conditions in the Pacific Ocean. The first U.S. fleet of crew transfer vessels is being developed at the present time to service the Block Island Wind Project off of Rhode Island.

Ships for laying power cables are highly specialized vessels typically owned and mobilized by a cable manufacturer / installer such as Prysmian and ABB. There are presently very few ships in the world that can lay undersea power cables. While the existing ships can be made available in Hawai‘i, the scheduling of these vessels can involve scheduling lead times of two to three years. High demand for undersea power cables for HVDC interconnections, and for the burgeoning demand related to the offshore wind industry in the United States, could lead to additional cable laying vessels being commissioned over the next few years.

Interconnection and Integration with the O‘ahu Grid

Interconnection and transmission integration issues for offshore wind projects serving the O‘ahu grid have not been studied in detail. The interconnection and integration infrastructure, and its cost, depends on a number of factors: the specific point of interconnection, existing transmission infrastructure, thermal generation deactivations, and new generation installations between now and the in-service date of the offshore wind project.

There will likely be a capital cost associated with accommodating an interconnection of this magnitude. Most certainly, substantial upgrades will be required at the point of interconnection. In addition, depending on the configuration of the power system at the time of interconnection, substantial transmission upgrades, or even new transmission, could be required to accommodate the injection of a substantial amount of power at one or two points of interconnection.

Integrating offshore wind into the O‘ahu grid is also an issue. Consider:

- The largest single unit contingency in the O‘ahu system is presently 180 MW (the AES Hawai‘i coal power plant). Increasing the largest single unit contingency has operating cost ramifications related to the amount of “spinning” reserve required to maintain the reliability of the O‘ahu power system. This may result in the necessity to divide a single 400 MW project into two separate groups for interconnection.
- As of today, the peak demand on O‘ahu (net of customer owned generation) is approximately 1,200 MW. A 400 MW wind facility operating at system peak would be supplying about one-third of O‘ahu load. The minimum system load (net of customer owned generation) is approximately 500 MW. A 400 MW wind facility operating at the minimum load hour would be supplying 80% of the O‘ahu load, leaving little room for must-run or firm, dispatchable resources to operate (renewable or otherwise).
- The total system net energy requirement on the O‘ahu system (including line losses, but excluding customer generation) is approximately 6,500 GWh per year (net of energy efficiency and distributed generation).[41] Therefore, a 400 MW offshore wind project with an annual capacity factor of 60% would provide approximately one-third of the total energy requirements for O‘ahu. With other renewable resources in the resource mix (including must-take DER resources), this will likely require either curtailment of renewable resources or energy storage to better match generation with demand.

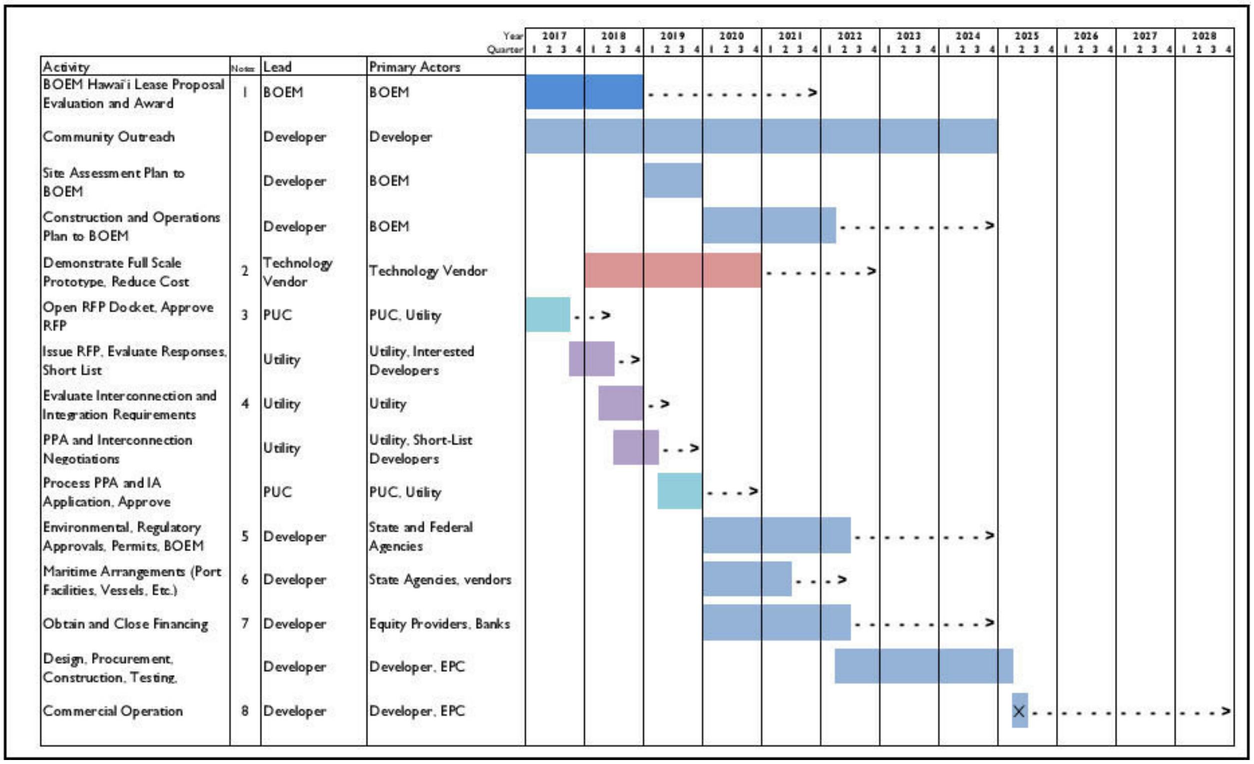
Utilizing wind energy from a single project might increase the total cost of providing ancillary services necessary for the grid to remain reliable, result in a concentration (that is, a less diversified portfolio) of renewable resources to meet Hawai‘i’s clean energy goals, and reduce the flexibility to accommodate other renewable resource options, including both grid-scale and DER options (although this is an economic and policy issue).

[41] *PSIP Update Report: April 2016*, *op. cit.*, Appendix J, Table J-10, page J-44.

Development Timetable

A *conceptual* timetable illustrating the time necessary for developing offshore wind reveals that, from today, a period of at least seven years will likely be required until commercial operation in Hawaiʻi.

Hawaiʻi Floating Platform Offshore Wind Conceptual Development Schedule



Notes: A dotted line with arrow (--->) denotes an area of significant schedule risk. The overall schedule impact is not shown.

1 BOEM has issued a call for lease proposals; indicated the process could take as long as five years.
2 Principle Power WindFloat scheduled for full scale prototype deployment in 2018.
3 Hawaiian Electric has filed a letter with the Hawaiʻi Public Utilities Commission requesting to open an RFP docket.
4 Interconnection issues for injection of 400+ MW of offshore wind into the Oʻahu system are likely to be substantial.
5 This includes legislative actions and, if required, DOD approvals. It does not include litigation costs after permits are issued.
6 Arrangements for use of local port facilities and appropriate vessels. Mainland fabrication is likely to add capital cost.
7 Financing is dependent on full scale prototype success, backing of technology performance by large balance sheet EPC, and the ability to ensure the project and acceptable O&M arrangements.
8 Earliest likely commercial operation date. The schedule risk is driven by other activities.

Figure H-17. Conceptual Development Timeline for Offshore Floating Platform Wind in Hawaiʻi

Key Findings

Several key findings emerge from our analysis of offshore floating platform wind energy.

1. Offshore wind technology is still in the development phase and will likely not be commercially available until at least the early 2020s.
2. The capital cost of offshore floating platform wind is forecasted to decrease as the technology becomes more mature. Developer estimates for installation in Hawai'i in the early 2020s appear to be too optimistic.
3. The BOEM process is defined. However, there are a multitude of additional agencies at the State and Federal levels that need to approve any offshore wind project in Hawai'i.
4. The BOEM leasing process will likely take several years.
5. The availability of local ports is constrained, which might impact schedule and costs of offshore wind in Hawai'i. Competing uses for port facilities might become a significant hurdle to constructing offshore wind platforms in Hawai'i.
6. Developing offshore wind projects requires a system of undersea, alternating current, power cables. Floating substations are envisioned for the Hawai'i offshore wind projects; there is currently little experience with floating substations.

Conclusions

Our assessment of offshore floating platform wind energy results in these conclusions.

1. It is unlikely that either Progression Energy or Alpha Wind can successfully develop an offshore wind platform in the time frames they have publicly claimed.
2. Offshore floating platform wind will likely become a commercially available technology during Hawai'i's energy planning horizon.
3. 2030 is a reasonable point in time during the planning horizon to include offshore floating platform wind as a renewable resource option available for installation in Hawai'i.
4. The viability of offshore floating platform wind as a renewable resource option for Hawai'i will depend on political and community acceptance, overcoming siting issues (including siting and routing of undersea alternating current power cables), and a decline in capital cost to economically feasible levels.

INTERISLAND TRANSMISSION

Interisland transmission cables, while technically feasible, must be considered on economics and policy.

Part of the answer to those considerations is to determine the ultimate purpose of interisland transmission. Interconnecting various island, always including O‘ahu, could result in lower overall operating costs. This is purely a financial analysis: do the benefits outweigh the costs. Interisland transmission also might be necessary to achieve the 100% renewable generation mandate.

Technically Feasible

The technology to construct and operate interisland transmission cables is technically mature, commercially available with operating installations around the world, and financially feasible in capital markets. Such cables have been shown to have a very high level of reliability.

Because of the distances, high voltage direct current (HVDC) technology is being used for interconnecting the islands of O‘ahu, Maui, and Hawai‘i, including converter stations on either end of a submarine cable. Submarine HVDC systems have been successfully deployed around the world; the market for HVDC systems is expected to dramatically increase in the future.[42]

There are relatively few vendors of HVDC technology. Active vendors are global players with large balance sheets with the ability to support this technology. HVDC systems exhibit a high level of reliability and are highly controllable, providing flexibility for providing grid services.

Cost estimates for interisland transmission cables range from connecting remote resources (such as wind developed on one island specifically to serve another island) to connecting two or more of our island grids for joint dispatch. Costs for HVDC projects are typically developed with the vendor providing turnkey engineering procurement construction (EPC) with guaranteed prices (subject to sliding cost categories related to commodity prices), guaranteed schedules, and guaranteed performance.

Potential vendors are unlikely to develop accurate costs for a specific interisland cable configuration unless they can be assured that the project has a high likelihood of development. Absent that assurance, a qualified party could be engaged, for a fee, to

[42] http://www.marketsandmarkets.com/Market-Reports/hvdc-grid-market-1225.html.

study, assess, and develop a comprehensive cost estimate. Currently, our lowest known capital cost estimate for a single 200 MW interisland transmission cable between O'ahu and Maui is approximately $600 million.[43] The capital cost for multiple cables with higher capacities will be significantly higher.

Developing an interisland cable in Hawai'i also faces a number of development challenges including: siting onshore infrastructure (for example, HVDC converter stations), integrating a cable with the existing power systems on connected islands, mitigating the impacts on marine mammals, avoiding deep sea corals, avoiding disturbances at archeological sites near coastal cable landing zones, permitting hurdles, cultural and social issues, among others. Many of these issues are shared with offshore wind, which also requires a system of undersea cables, but adds the complication of developing resources on one island to be used by another island.

Essentially, the decision to install interisland transmission cables is driven by two factors: economics: do the benefits outweigh the costs; and policy: do the benefits accede to social acceptance and political will.

Interisland transmission, if installed, also changes the underlying electric power structure from individually separated island grids to interconnected grids—for decades. The lifespan of HVDC cables approaches 40 years.

Policy Issues

Proposals for undersea cables to provide O'ahu access to energy resources located on other islands have been around since at least 1881, when King David Kalākaua visited Thomas Edison in his New York Laboratory.[44]

A substantial issue, thus, is the ability to actually develop renewable resources on the islands interconnected to O'ahu. The public has expressed concern regarding development of wind projects in Maui County particularly if the power is intended for consumption on O'ahu. Similarly, there has been expressed public concern to development of additional geothermal resources on Hawai'i Island. Proposals were made to build 200 MW of wind power on Moloka'i and 200 MW of wind power on Lana'i for transmission to O'ahu.

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[43] NextEra Energy developed and filed the $600 million estimate in Docket No. 2014-0169. (NextEra has since withdrawn from that proceeding.) This amount is at the low end of the $553–$969 million estimated range filed in our 2013 Integrated Resource Plan Report, Appendix H: Inter-Island Transmission Costs, for the capital cost of connecting O'ahu with Maui to transmit 200 MW of energy with a HVDC non-redundant cable. NextEra's estimate, however, is well below that adjusted-for-inflation $760 million to $1.24 Billion range that included permitting and other development costs such as land acquisition. In addition, it's unclear whether NextEra's cost estimate includes the transmission system improvements and upgrades necessary to interconnect O'ahu and Maui.

[44] http://hawaiiankingdom.org/blog/kalakaua-visits-edison-the-king-in-search-of-a-means-to-light-up-honolulu/.

First Wind, and later Pattern Energy, withdrew from pursuing the Moloka‘i wind project. Castle & Cooke sold its interest in real estate on Lana‘i to Larry Ellison, but retained the rights to construct a wind project on Lana‘i. However, the status of Castle & Cooke's continued plans for wind development on Lana‘i is unknown.

In 2013, the Hawai‘i Public Utilities Commission opened Docket 2013-0169 for the purpose of determining if interisland cables were in the public interest. After two rounds of comments from interested parties early in the life of that proceeding, Docket 2013-0169 has largely been inactive.

In April 2014, the Commission instructed the Companies to evaluate the feasibility of interisland cables[45] as part of the PSIP process. The Commission did not specify what purpose an interisland cable might serve, and therefore left it to the Companies to make that determination. Our 2014 PSIPs included an economic evaluation of interconnecting the O‘ahu and Maui power systems to achieve savings through joint dispatch. We found, however, that the gross benefits of such an interconnection was substantially less than the estimated cost of a cable. Thus, we concluded that interconnection solely for dispatch benefits was not economically feasible.

In Order No. 33320, the Commission ordered the Companies to further evaluate the feasibility of interisland transmission, particularly given the 100% RPS goal set forth in Act 97. Our 2016 updated PSIP analyzed the feasibility of interisland transmission, which focused on determining if there is an optimal plan for achieving Hawai‘i's overall RPS goals through island interconnection compared to optimizing each island separately.

Rather than developing an accurate capital cost, we decided to first analyze the *benefits* of interisland transmission to determine if the sum total of such benefits could reasonably exceed this approximated cost. This break-even analysis assumes various "copper plate" configurations: assume one or more cables transfers power between two or more points, without consideration of reliability (that is, the need for redundant cables); comparing the benefits against $600 million; and if benefits exceed cost, then conduct further analysis. For example, cumulative benefits of interconnecting O‘ahu and Maui[46] that approach $600 million would warrant more detailed analysis.

[45] Decision and Order No. 32052, Docket No. 2012-0036.

[46] For perspective, our 2014 PSIPs showed a maximum benefit of approximately $300 million the so-called "copper plate" configuration for and interconnection between O‘ahu and Maui (net present value gross savings)—about half the lowest estimated cost of $600 million.

This additional analysis would include:

- Identifying the on-island transmission system upgrades required to interconnect the interisland cable, including an analysis of prospective interconnection points.
- Analyzing reliability and system security to determine the issues associated with operating an interisland cable.
- Retaining a third-party qualified to develop a detailed cost estimate for installing an interisland cable and a preliminary list of issues necessary for obtaining permits and approvals.

The benefits of interisland transmission are part of developing this December 2016 PSIP.

Our goal is to determine, as quickly as possible, whether or not interisland transmission represents a viable resource option for Hawai'i that demands further analysis. We believe this two-step process—first evaluating the benefits, then, if warranted, evaluating the cost—is the most prudent, cost effective, and timely way to determine if interisland transmission demand further consideration as an option to pursue to help achieve our State's renewable energy goals. Regardless, interisland transmission will require many years to develop, and as such, will not have an impact on our near-term action plans.

HYDROKINETIC ENERGY

Hydrokinetic energy captures the energy from flowing water that occurs in rivers and mostly in ocean currents. This technology includes:

- Tidal barrage
- Tidal stream (and river in-stream energy)
- Ocean current
- Ocean wave
- Ocean thermal conversion
- Salinity gradient

The latent potential for hydrokinetic energy is, to put it mildly, extraordinary. Table H-10 compares the potential contribution that the various hydrokinetic energy technologies toward attaining the current worldwide energy production of 17,400 terawatt hours per year. Further, power from the ocean is relatively predictable, mostly firm generation. The overall potential, if ever realized, would easily generate enough energy to power the entire world, and could power over five times that amount.

Hydrokinetic Technology	Estimated Global Resources (TWh per year)	Percentage of Current Global Electricity Production
Tidal Barrage	300+	1.7%
Tidal Stream	800	4.6%
Ocean Wave	8,000–80,000	46%–460%
Ocean Thermal	10,000	57.5%
Salinity Gradients	2,000	11.5%
Totals	21,100–93,100	121.3%–535.3%

Table H-10. Hydrokinetic Energy Global Electricity Production Percentages

While hydrokinetic energy has incredible potential, none of these technologies are close to being commercially ready and would take decades to be realized. While a fair number of pilot and experimental projects are being implemented worldwide, their potential is essentially untapped. Notice that the ocean current technology is missing from Table H-10, mainly because it's merely conceptual.

A report by The International Renewable Energy Agency (IRENA) described the six basic hydrokinetic technologies, and their related readiness and potential, which are summarized in Table H-11.[47]

Technology	TRL*	Readiness	Description	Conditions for Deployment	Hawai‘i Potential
Tidal Barrage (Tidal Range)	9	Commercial, but few projects developed.	Based on conventional hydropower technology. Impoundment of water near shore with tide filling the reservoir.	Large daily tidal fluctuations; very specific site characteristics.	Low
Tidal Stream	7–8	Prototype testing in field environments.	Capture tidal flow through constrained topography (for example, channels, bays, harbors) via underwater turbines.	High tidal fluctuations; specific geological features.	Low
Ocean Wave	6	Pre-commercial prototypes with commercialization goals for the "next decade".	Various concepts for capturing energy from waves.	Best potential between latitudes of 30° and 60°.	Medium
Ocean Thermal	5-6	Pilot-scale test facilities, but no long term operation.	Utilizes temperature differentials between surface and deep water in a Rankine Cycle, with special working fluid.	Best potential between latitudes of 0° and 30°.	High
Ocean Current	4-5	Conceptual. No prototypes ever tested or demonstrated.	Capture energy from major ocean currents (open ocean) via underwater turbines.	Energy demand in proximity to major ocean currents.	High
Salinity Gradient	4	Conceptual.	Harnesses the chemical potential energy between fresh water and salt water	Distributed globally. Best areas where rivers meet the ocean.	Low

* See Table H-7 for a description of the Technical Readiness Levels

Table H-11. Hydrokinetic Technologies Readiness and Potential

For Hawai‘i, the recoverable energy potential from wave power alone has been estimated to be about 80 terawatt-hours per year,[48] roughly equal to the state's annual energy demand across all fuels (that is, electricity, gasoline, jet fuel, and others).[49]

When available, implementing certain hydrokinetic technologies would require addressing many of the same issues highlighted for offshore floating platform wind: siting, permitting, port facilities, competing uses of the ocean resources, and others. While the promise of extracting usable energy from the ocean is worthy of pursuit by researchers and technology developers, no "off-the-shelf" technology is available today

[47] *Ocean Energy Technology Readiness, Patents, Deployment Status and Outlook*, IRENA, August 2014, at xi; available at: http://www.irena.org/DocumentDownloads/Publications/IRENA_Ocean_Energy_report_2014.pdf.

[48] http://www.boem.gov/Ocean-Wave-Energy/.

[49] According to the Energy Information Administration, total energy demand in Hawai‘i in 2014 was 281.2 trillion Btu's. http://www.eia.gov/state/seds/data.cfm?incfile=/state/seds/sep_sum/html/rank_use_gdp.html. Conversion of Btu to kWh at a rate of 0.000293071 kWh/Btu yields an equivalent of 82.4 terawatt-hours.

for Hawai‘i that can generate power in meaningful quantities. Based on current condition, several more decades might pass before such technologies achieve commercial viability.[50]

Even though it's impossible to predict the future commercial availability, cost, and performance characteristics of hydrokinetic technologies for Hawai‘i; the chance that one or more of these hydrokinetic technologies becomes viable within our near-term action plan is highly implausible. Because of this, we did not consider these technologies in our resource planning. When such technologies are commercially available and can readily be financed, they could become viable options to replace power supply options such as wind, solar PV, geothermal, biomass, and other renewable resources.

Tidal Barrage

Tidal barrage employs the vertical difference between high and low tides. It requires 10 meters of vertical difference between the ebb and flood of tides. The technology is similar to conventional hydroelectric dams.

There is both ebb generation and flood generation. For ebb generation: while the tide is rising, the reservoir behind the dam is filled with water through open sluices while the turbine gate is closed. When high tide is reached, the sluices shut. When the ocean level has receded to sufficiently low levels, the turbine gate opens and the water from the reservoir is channeled onto the turbine, thus generating electricity. For flood generation: while the tide is rising, water flows through the turbine into the reservoir, generating electricity during the flood. Ebb generation is more efficient than flood generation.

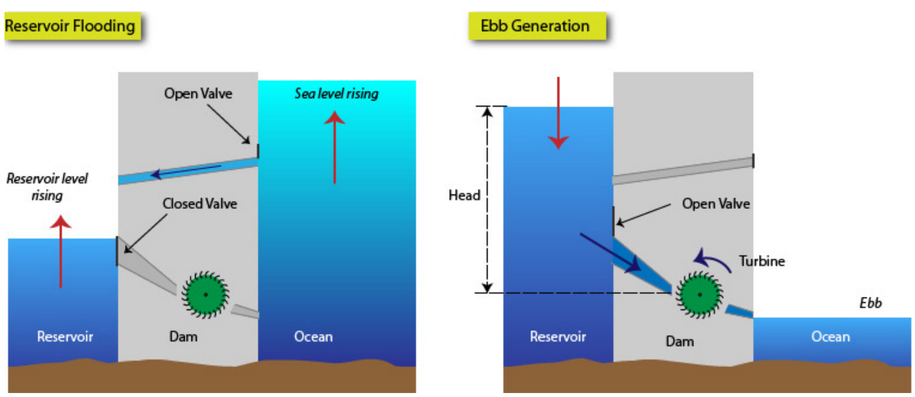

Figure H-18. Tidal Range Reservoir Flooding and Ebb Generation

[50] See: http://e360.yale.edu/feature/why_wave_power_has_lagged_far_behind_as_energy_source/2760/ and http://e360.yale.edu/feature/will_tidal_and_wave_energy_ever_live_up_to_their_potential/2920/.

While the potential for tidal barrage is huge, there are only 50 sites worldwide in six regions for implementation: the Bay of Fundy, Canada (with up to 12 meters mean tide); Bristol Channel and Cardiff Bay, United Kingdom; Normandy, France; Magellan Strait, Argentina and Chile; Cook Inlet, Alaska; and Penzhinskaya Bay, Kamtchatka, Russia. In addition, environmental concerns have limited expansion. No sites have been identified in Hawai‘i.

Only two sites worldwide are currently operating. The La Rance estuary plant in France (operating since 1966) generates 240 MW while the Bay of Fundy facility generates 8 MW. Both South Korea and China are currently building tidal barrage facilities. Russia is in the planning stages of building an enormous 87 GW tidal barrage facility in Kamtchatka.

Tidal Stream

Tidal stream turbines exploit the kinetic energy from the water flowing in and out, in both ocean and river sites. Good sites have flow speeds of more than four meters per second in 40 meter depth. The technologies are similar to wind turbines. Apart from tidal barrages, tidal stream is the most developed marine technology with some projects on the brink of going commercial. Its low environmental impact favors tidal stream over tidal barrage.

Ocean Renewable Power Company (ORPC) installed their TidGen tidal generator turbine (Figure H-19) in Cobscook Bay in Eastport, Maine. TidGen is expected to increase the size of the generator to 5 MW gross, and maintain that for the length of their 20-year PPA.

Figure H-19. ORPC TidGen Tidal Generator

ORPC also installed their RivGen river generator turbine in the Kvichak River, adjacent to Igiugig, Alaska. On August 31, 2016, the U.S. Department of Energy awarded $5,350,000 to ORPC to enhance the performance of its tidal turbine system.

Figure H-20. ORPC RivGen Generator

Ocean Wave

Wave height and wave period (for horizontal speed) is used to generate energy. Typical wave height is 3 meters; its wave period is eight second. Because of these two types of wave energy, conversion is complex. As a result, technologies are also complex and sited far offshore for the best wave consistency.

Successful demonstration wave power projects have been implemented in several locations around the world, including Hawai‘i. Small grid-scale wave energy projects have been installed in Europe (such as the one depicted in Figure H-21).

Figure H-21. Pelamix Wave Energy Converter at the European Marine Energy Test Centre, 2008

Carnegie Wave Energy is undertaking the design, construction, installation, and demonstration of a grid-connected wave generation project with up to 3 MW peak installed capacity off Garden Island, Western Australia. The project will deploy three grid-connected of the company’s CETO 6 units.

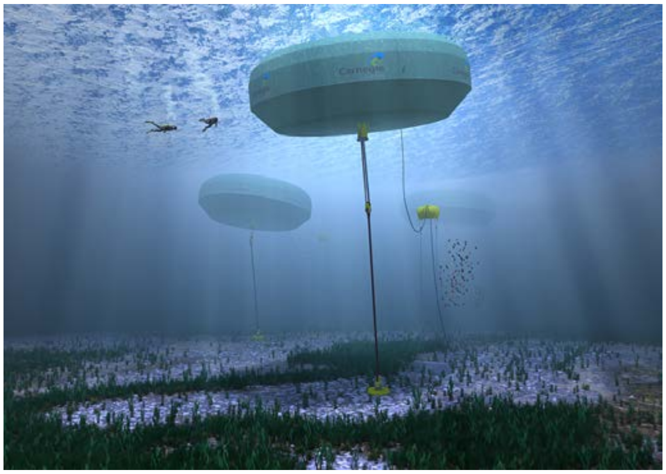

Figure H-22. CETO 6 Wave Energy Oscillating Buoy

The CETO 6 buoy oscillates with the ocean’s waves, transferring energy to a power conversion unit located inside the buoy, generating power offshore and transmitting it onshore via a subsea cable. The Australian Department of Defense intends to purchase the power generated by the project, which will provide electricity for HMAS Stirling, Australia’s largest naval base.

Closer to home, we currently partner with the U.S. Navy (and others) in a small-scale pilot. On September 18, 2016, the first wave-produced electricity went online in Kaneohe Bay on O‘ahu. The project consists of two buoys that each capture the ocean’s movement and convert it into electricity. One buoy produces 18 kilowatts of energy; the other produces 4 kilowatts. According to published reports, wave energy technology is at about the same stage as the solar and wind industries were in the 1980s.

Ocean Thermal Energy Conversion

The temperature difference between surface and deep water can be used to drive a turbine. Warm surface water vaporizes an expanding gas that drives a turbine. Cold, deep ocean water cools the gas to a liquid, which is pumped backed to the vaporizer.

Hawai‘i is a pioneer in ocean thermal energy conversion (OTEC) research, having demonstrated the first successful OTEC project on Hawai‘i Island in the 1970s. Currently, there are two ocean energy projects installations in Hawai‘i, both the first of their kind to be connected to a United States grid. In August 2015, Hawai‘i's Makai Ocean Engineering completed the world's largest operational OTEC power plant at its facility in Kona on Hawai‘i Island.

Figure H-23. Makai OTEC Generator

The OTEC power plant uses the temperature difference between the near-freezing deep water of the ocean and the surface waters heated by the sun to generate electricity. The plant produces 100 kilowatts of energy. In addition, a 1 MW OTEC plant is planned for the Hawai‘i Ocean Science and Technology Park in Kailua-Kona on Hawai‘i Island. Unfortunately, OTEC International (OTECI), which had proposed a 100 MW OTEC project to serve O‘ahu, announced that it was withdrawing from the Hawai‘i market.[51]

Although the thermal energy stored in oceans is huge, the low temperature difference of 20°C over a length of one kilometer makes it very difficult to exploit. Despite the technological promise of OTEC for large-scale electricity generation, no full-scale OTEC plant has yet to be built anywhere in the world; and the prospects appear decades away.

[51] http://www.utilitydive.com/news/heco-developer-shelve-100-mw-ocean-thermal-energy-project-off-hawaii/401000/.

Salinity Gradient

The salinity gradients between the natural mixing of fresh and salt water provides large amounts of energy, which this technologies aims to capture. Originally discovered in the 1970s, research has been slow and most of it recent. Research focuses on two practical methods: the reverse electrodialysis (RED) method and pressure retarded osmosis (PRO). Both technologies are dependent on selective semi permeable, ion-specific membranes (that is, only specific substances can pass through the membrane).

Siting is very location specific, although there are a large number of possibilities. While the majority of components required for a salinity gradient power have reached commercialization, the technology is still in its infancy. No salinity gradient power plants—conceptual, pilot, or functional—have been built anywhere in the world.

Commercial Prospects

Hydrokinetic power exhibits similar development challenges as offshore floating platform wind: siting, permitting, and financing. Implementing large-scale tidal and wave installations has thus far been hampered by a lack of understanding of the associated siting and permitting challenges in multiple jurisdictions. Wave and tidal power projects may face similar interconnection challenges as offshore wind.

The uncertainty and long time frames associated with achieving technology readiness and commercial availability of hydrokinetic energy suggest that this technology should not be considered an available renewable energy resource during the current PSIP planning cycle. Commercialization of hydrokinetic technologies is likely at least two, if not three, decades away. Success of the floating platform wind energy industry, however, could pave the way for these ocean technologies as they are perfected.

Should this technology become commercially viable in a large scale and demonstrate the ability to be financed without substantial subsidies, we will reconsider including wave and tidal power as a resource option in future resource plans.

I. Financial Analyses and Bill Impact Calculations

In our analyses, the Companies developed alternative approaches to achieve 100% RPS, analyzed the differentials between cases, and prepared comprehensive total customer bill impact and rate analyses. These results are described in Chapter 5: Financial Impacts.

Preparing comprehensive bill impact and rate analyses for a nearly 30-year planning period is an unusual level of financial planning and projections in the industry. While the Resource Plans provide the expected fuel cost, operating costs, and capital investments for critical resources given our resource cost assumptions and fuel price forecasts, the capital investments and operating expenses for the balance of our utility business needs to be projected and incorporated into the comprehensive bill impact and rate analyses; in other words, our non-power supply costs.

To meet this challenge, we developed a top-down methodology to project this "balance-of-utility business" capital and expense requirements.

ITERATIVE TOP-DOWN METHODOLOGY

Our non-power supply cost structure—and correspondingly its revenue requirement and customer bills in total—comprise four primary elements.

- Operating & maintenance costs.
- Taxes other than income and public benefits fund.
- Return on and of existing utility asset investments.
- Return on and of future utility asset investments, net of productivity savings.

We integrate the non-power supply cost structure with the power supply forecast to develop a holistic plan by operating utility. We then apply a financing capacity test and a rate change test and make adjustments as needed to ensure the results are within acceptable ranges.

Financing Capacity Test

We currently have a limit to the amount of new capital expenditures we can finance on terms acceptable to both customers and shareholders. There is a ceiling on the total capital expenditures of the consolidate plan in a given year or period of years.

The annual capital expenditures of the power supply plans and the future annual capital expenditures for the balance of the business are summed by year to determine if the total capital expenditures are within the Companies' financing capacity. Projected capital expenditures for both the power supply plans and the balance of the utility business are evaluated for operational needs along with the need to stay within the Companies' financing capacity. The adjusted capital expenditure plan is then used for the customer bill and rate impact analyses.

Rate Change Test

There are also economic and policy limitations to levels of future changes in customer bills and rates. While the science of these limits maybe somewhat less precise than the financing capacity limits discussed above, these limits are real and constraining.

To determine an annual rate change test limitation for each operating utility against which to test the plans, three different approaches to project annual rate changes were considered. These are:

- Rates adjust at the rate of inflation.
- Rates adjust at a blended rate, reflecting fuel price forecasts[1] and general inflation for "business as usual"[2] operations.
- Rates adjust at the rate of price change over the prior decade.

These approaches, when applied to each operating utility, result in the following annual rate change scenarios (shown in Figure I-1 through Figure I-3).

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1 The fuel price component of these rate trajectories have been adjusted to reflect fuel blending required to meet environmental regulations.

2 "Business as usual" in this context means continued use of the existing generating portfolio and fuel types, consistent with environmental regulations.

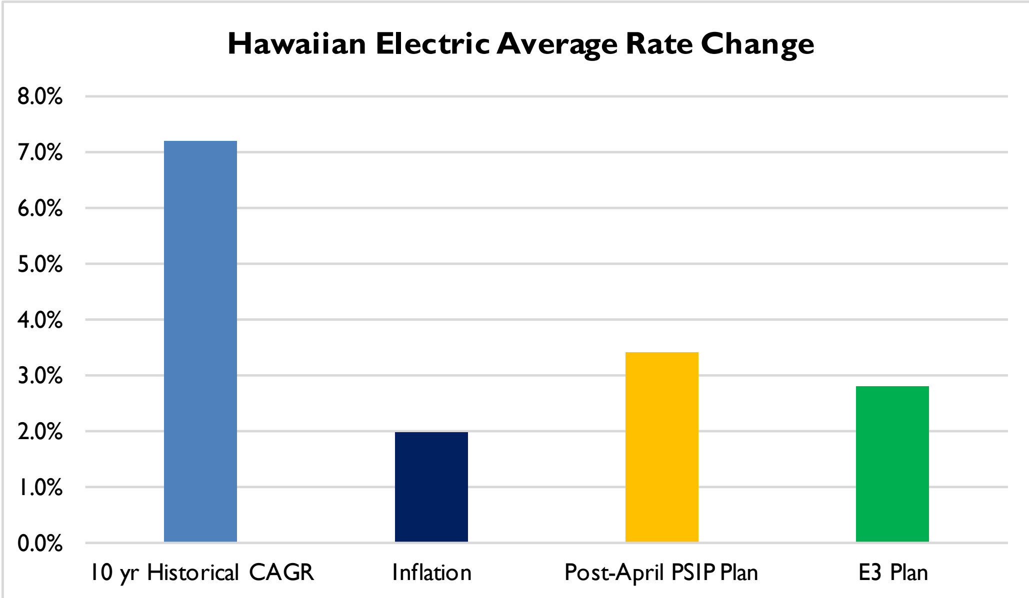

Figure I-1. Hawaiian Electric Average Rate Change

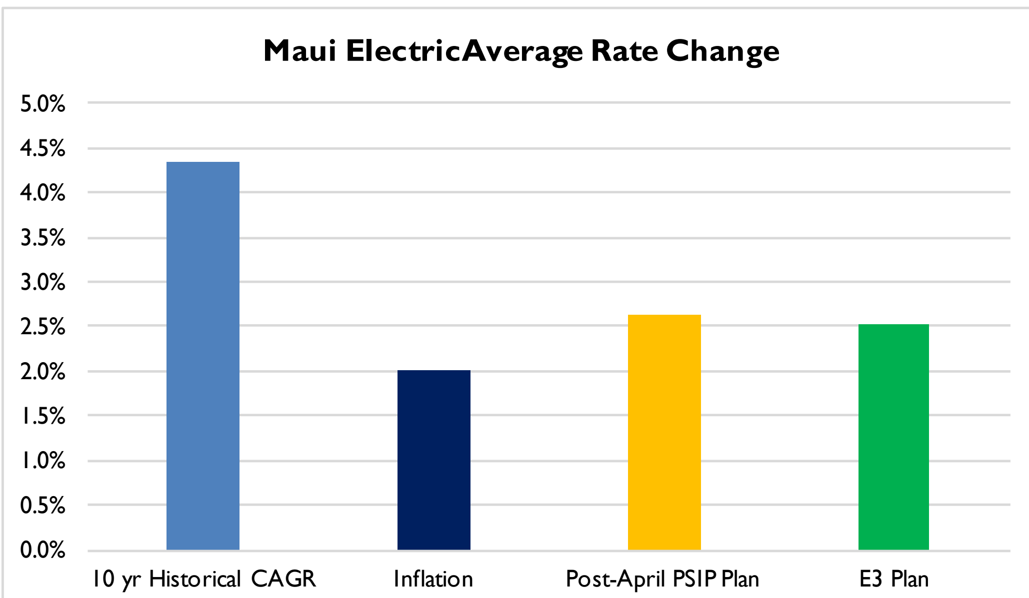

Figure I-2. Maui Electric Average Rate Change

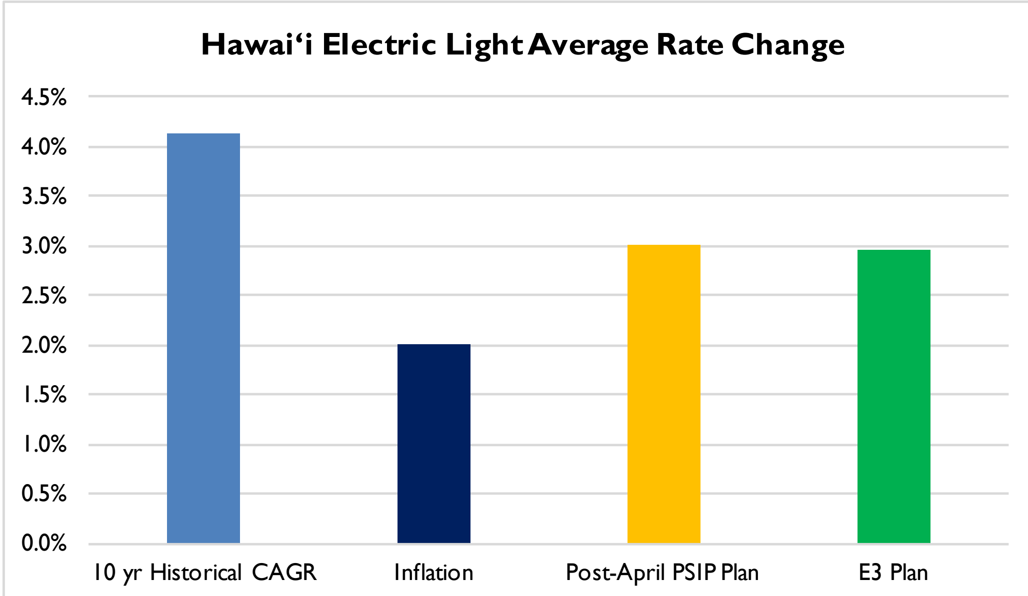

Figure I-3. Hawai'i Electric Light Average Rate Change

In addition to these annual rate change data points, we understand that there is a price point beyond which customers have economically feasible alternatives to grid supply. While there are many quantitative and qualitative factors that go into such a decision, we know that we must deliver to our customers an attractive total value proposition of affordability, reliability, and convenience. Based on these analyses, we targeted an annual rate change ceiling of 4%, with exceptions made in certain years for implementation of significant major capital projects, while giving consideration to the operational needs for balance of the utility business capital expenditures.

The lumpy rate increases inherent with tradition rate base treatment of major capital projects are a challenge in this context. One approach that could be used to smooth out the rate impact of significant major capital investments is to allow for the inclusion of the Construction Work in Progress (CWIP) associated with major projects to be included in rate base. This approach would also benefit customers through a lower total cost for each project, as AFUDC financing charges would not be added to a project's cost. This treatment for major capital investments is one that a number of other jurisdictions have adopted; while we have not included that treatment in our rate and bill impact calculations, we believe it is a concept that should be considered, perhaps for all new significant major projects greater than $50M, as these plans move from proposals to projects.

It is important to note that annual rate change is a more constraining constraint as compared to total bill impact because of the anticipated sales volume reduction impact of energy efficiency measures.

Impact of Energy Efficiency Portfolio Standard on Rates and Customer Bills

Hawai'i's Energy Efficiency Portfolio Standard (EEPS) is guiding significant improvements in energy efficiency across all customers and is a primary driver of the decline in kWh sales through 2030. These usage declines are incorporated into the sales forecasts used for the PSIP analyses. Figure I-4 provides a perspective on the significance of this impact on projected sales volume for O'ahu. While these net sales figures include the impact of both EEPS and the standard DER penetration assumptions, the DER impact is generally constant year to year, so the shape of the curve is driven by the EEPS impact.

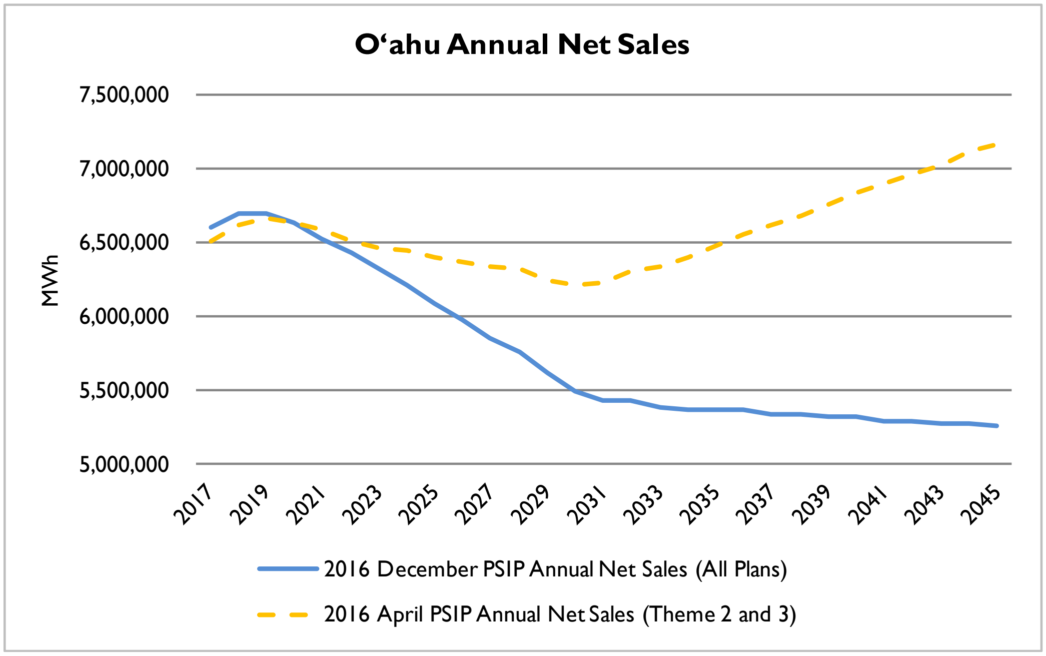

Figure I-4. Impact of Energy Efficiency Portfolio Standard on Sales

These sales volume changes are allocated across all customer classes in the PSIP analyses and do impact both the residential rate and residential customer bill impact analyses. While factors, including the applicable level of DG-PV penetration, do impact the specific calculations by resource plan for each island, the calculated usage per non-DG-PV residential customer varies with the EEPS driven net sales decline (Figure I-5).

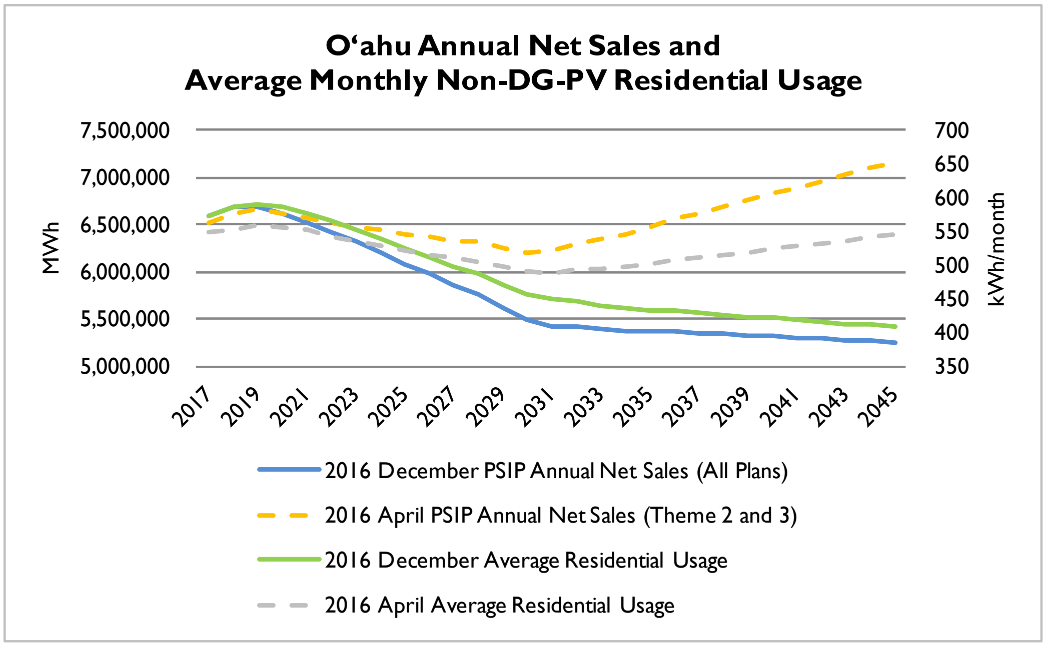

Figure I-5. Impact of Energy Efficiency Portfolio Standard on Sales & Residential Usage

Applying the Rate Change Test Iteratively

To test each scenario against this initial rate change limit, we have combined the annual capital expenditures, fuel, and operating costs associated with the PSIP Plans with the annual capital expenditure and operating cost projections for the balance of the utility business to calculate an initial rate impact for each. We use the twelve month average 2015 residential rate level for each island as the starting point for this analysis. The use of a twelve month average rate provides some degree of smoothing to the very volatile monthly rates customers have experienced, due to the dramatic swings in oil prices.

For any year in which an operating utility plan results in a rate change greater than the annual ceiling, we review and adjust the timing and magnitude of the capital expenditures associated with the balance of the utility business or of significant major projects within that time frame, as appropriate. Exceptions were allowed in certain years due to the implementation of significant major capital projects.

Through iteration we calculate a capital expenditure profile that results in annual rate changes less than or equal to the ceiling, with limited exceptions due to significant major projects, and is consistent across all plans, so as to ease direct comparison of revenue requirements and customer bill impacts between plans.

Alignment with Existing Capital Plans and Ability to Meet Customer Requirements Test

This top-down, balance-of-utility business constrained capital expenditure plan will be reviewed to ensure that it reflects investment levels that will continually meet customer requirements for new service, maintain or enhance service reliability, and enable timely modernization of the grid to enable the distributed energy resources called for in the PSIP Plans. Management judgment will be applied to the timing and magnitude of the total capital expenditure plan to adjust as appropriate so as to ensure these critical customer requirements will be met.

Resource Usage Test

Lastly, final balance-of-utility business capital expenditure plan will be reviewed from a resource management perspective. Cost effective execution of capital work requires effective use of existing and future Company resources, especially in transmission and distribution. A degree of consistency in the level of investment is highly desirable given the availability and mobilization costs of contract resources in Hawai‘i and the required investment and timeline for training and development of Company resources. Here again, management judgment will be applied to determine if adjustments to the magnitude and timing of the final balance-of-utility business capital expenditure plan is required.

OPERATIONS AND MAINTENANCE EXPENSES

Operating and maintenance (O&M) expenses are a broad category of expense, which we have projected in three distinct ways. First, PSIP-related O&M is projected for each resource plan as modeled, based on the resource cost, retirement, and transition costs associated with each resource plan. Second, for Smart Grid and ERP, specific O&M cost adjustments are used, consistent with the respective General Order 7 applications.[3] Third, for Hawaiian Electric and Hawai‘i Electric Light, specific requested rate case increases[4] for O&M are used for the 2017 and 2016 test years respectively. For Maui Electric’s expected 2018 Test Year Rate Case, the test year O&M increase was based on the average of Hawaiian Electric’s and Hawai‘i Electric Light’s submitted rate cases identified above. The remaining operating and maintenance costs are projected to increase at the rate of inflation over the 30 year forecast period.

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3 Applications to the Commission for approval to commit funds in excess of $2.5 million.

4 Hawai‘i Electric Light 2016 Test Year Rate Case, Docket No. 2015-0170; Hawaiian Electric 2017 Test Year Rate Case, Docket No. 2016-0328.

This assumption represents an intense pressure on operating costs, as labor costs comprise a significant percentage of these operating costs and skilled labor costs have consistently risen at rates above inflation in recent years. When this relationship is extended out over 30 years, it implies either a reversal of this labor cost relationship or very significant productivity gains must be achieved in order to meet this operating cost projection. If such gains are not achieved, future operating costs will be higher than the costs incorporated into the customer bill impact and rate analyses.

TAXES OTHER THAN INCOME AND PUBLIC BENEFITS FUND

A material component of a customer's total electric bill is comprised of various taxes the Companies pay, as well as the public benefit fund charge the Companies collect to fund Hawai'i Energy's energy efficiency programs. The laws and regulations that govern these taxes and fees are assumed to remain constant throughout the forecast period. Taxes on fuel that are assessed volumetrically are projected consistent with the plan's expected fuel consumption. Other fees are assumed to increase at the rate of inflation.

The current public benefit fund charge of 2% of electric revenues, including revenue taxes, was applied throughout the planning period.

RETURN ON AND OF EXISTING UTILITY ASSETS

The Companies have $4.1 billion of net utility assets, as of December 31, 2015, including $1.0 Billion of generating property, plant, and equipment assets. These existing assets are currently used and useful for utility service, are being depreciated, and the net balance is in rate base earning a return, based on the authorized capital structure and return on equity. The customer bill impact and rate impact analysis assumes the currently authorized capital structure, return on equity, and interim rate adjustment mechanisms are constant over the forecast period. Similarly, the analyses assume that depreciation rates for existing plant remain the same. Lastly, the analyses assume that upon retirement, undepreciated plant balances are transferred to a regulatory asset amortized over 20 years and that removal costs in excess of removal costs already recovered from customers, if any, are given the same regulatory treatment.

CAPITAL INVESTMENTS IN POWER SUPPLY ASSETS

For each resource plan, all of the capital investments associated with the plan are summed by year to reflect the total annual capital expenditure for the new resources envisioned in the plan. In addition, each plan also includes the capital expenditures required for the major reliability investments for each existing generating unit that is expected to operate well into the 2030s or beyond. Lastly, routine generation capital expenditures already planned for 2017 through 2020 are included, and a provision of $1 million per year per unit for capital expenditures associated with break or fix activities is included for each existing generating unit that remains operational beyond 2020.

These capital expenditures were modeled using the traditional rate base approaches for determining revenue requirements and customer rates. This approach assigns the capital cost recovery risk for these investments to customers and to the extent certain customers disconnect from the grid or significantly reduce their grid consumption, capital cost recovery would be shifted to the remaining customers. While the Companies are not yet in a position to make a specific proposal, we believe it is likely that capital cost recovery for certain of these power supply investments would be appropriately treated as a cost that cannot be bypassed. To the extent that we determine this is the case, we would anticipate including such a recommendation as part of any filing seeking approval of such a capital project.

BALANCE-OF-UTILITY BUSINESS CAPITAL INVESTMENTS

The iterative top down methodology uses "balance-of-utility business" capital expenditures, as one of the adjustable inputs to achieve an acceptable rate trajectory. The balance of utility business capital expenditures are divided into two specific categories: (1) significant "balance-of-utility business" major project and (2) all other utility capital expenditures.

Significant major projects, requiring GO7 approval, include Smart Grid and ERP/EAM. Total capital expenditures and deferred software costs for these projects[5] are projected as follows:

- Significant "balance-of-utility business" major project capital expenditures
  - Smart Grid: $346 million
  - ERP/EAM: $78 million

[5] These are the cost estimates available at the time of this analysis. For the most complete and current cost estimates for these projects, please refer to the most recent filings applicable to each.

It should be noted that capital expenditures for new office or yard facilities are not included in the customer bill impact and rate impact analyses. If, as the Companies continues to evaluate our facility requirements in the normal course of business, new facility investments can be justified, those would be evaluated on a stand-alone business case basis.

To frame the level of balance-of-utility business capital expenditures required over the forecast period, we considered several sources and perspectives. These include:

- Balance-of-utility business capital expenditure benchmark data for U.S. utilities indicate that for utilities with aging T&D assets, capital expenditures in the $400 to $600 per customer per year range are typical. This would suggest the following ranges for each operating utility:
  - Hawaiian Electric: $120 million to $180 million
  - Maui Electric: $30 million to $45 million
  - Hawai‘i Electric Light: $30 million to $45 million
- Hawaiian Electric's most recent five years have averaged approximately $190 million
- Engineering assessments across the Hawaiian Electric grids indicate significant reliability and capability issues that need to be addressed to ensure reliable service, particularly so given Hawaii's exposure to hurricanes and other major storms.
- Historical averages for a panel of US utilities indicate that approximately $7.5 billion in balance of business utility capital expenditures are required for each 1% growth in GDP. Using DBEDT's forecasted growth rate of 2.33%, the projected balance-of-utility business capital expenditures are:
  - Hawaiian Electric: $178 million
  - Maui Electric: $44 million
  - Hawai‘i Electric Light: $43 million

Given these data, it is expected that the combination of the PSIP Preferred Plan capital expenditures and rate change limits could constrain balance-of-utility business capital expenditures for at least the first 10 to 15 years of the planning period.

RETIREMENT AND REMOVAL COSTS

All of the Plans call for the deactivation and subsequent retirement of existing fossil generation units. For financial modeling, each unit is considered to be retired two years after it is deactivated, unless reactivation is explicitly planned in the resource plan. Further, we have assumed that each unit is removed in the year following retirement.

The net book value at retirement and the removal costs represent prudent expenditures that have served customers for many years and thus will need to be recovered from customers. We expect to seek Commission approval for recording these costs as a regulatory asset, to be amortized and recovered from customers over the 20 years following unit retirement. The financial results presented in this report are based on this approach.

Table I-1 presents the net book value of the units to be retired, annual depreciation expense, as well as the estimated removal costs for each.

Unit / Millions	Net Book Value: December 31, 2015	Annual Depreciation Expense	Estimated Removal Costs
Honolulu 8 & 9	$49.4	$1.6	$20.0
Waiau 3 & 4	$22.7	$0.9	$20.0
Waiau 5 & 6	$39.8	$1.2	$20.0
Kahe 1–3	$76.7	$2.4	$30.0
Kahe 4	$24.9	$1.0	$10.0
Kahului 1–4	$5.4	$1.4	$10.9
Puna Steam	$11.4	$0.4	$4.0
Hill 5 & 6	$14.5	$1.0	$9.0

Table I-1. Financial Data of Units to Be Retired

With the shift to renewable energy sources, several of the resource plans call for converting the generator of retired generating units for use as a synchronous condenser. In those cases, we have assumed that the generator assets and common plant that continue to be used for synchronous condenser operations will have a net book value of $2 million per unit that will remain in service and $1 million of removal costs will be avoided.

The net book value at retirement and the removal costs incurred represent prudent expenditures that have served customers for many years and thus will need to be recovered from customers. The financial results represent recovery of these costs from customers over a 20-year period following unit retirement.

In prior PSIPs, we modeled the recovery of retirement and removal costs through a securitization mechanism. While this approach could be used, it may not prove to be cost effective because these costs are somewhat smaller than previously anticipated and are spread out over a number of years. This makes the administrative costs of establishing and using a securitization mechanism appear impractical.

We expect to seek Commission approval for recording these costs as a regulatory asset, to be amortized and recovered from customers over the 20-years following unit retirement.

There is one aspect of a standard utility securitization that does seem to be appropriate for these costs. Recovery of these costs on a non-bypassable basis from all current and future customers would be appropriate, as all current customers have benefited from the use of these assets. While this rate design topic is beyond the scope of this 2016 updated PSIP, we suggest that this concept be considered in future rate design discussions relating to retirement and removal costs.

J. Modeling Assumptions Data

The Companies created this PSIP based on the current state of the electric systems in Hawai'i, forecast conditions, and reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs. As a result, this plan presents a reasonable and viable path into the future for the evolution of our power systems. We have documented and been fully transparent about the assumptions and methods used to develop this plan. We recognize, however, that over time, these forecasts and assumptions may or may not prove to be accurate or representative, and that the plan would need to be updated to reflect changes. We will continually evaluate the impacts of any changes to our material assumptions, seek to improve the planning methods, and evaluate and revise the PSIP to best meet the needs of our customers.

This appendix summarizes the modeling assumptions data used as input to our analyses conducted for creating the PSIP. This data includes:

- Reliability criteria
- Utility cost of capital
- Fuel price forecasts and availability
- Energy sales and peak demand forecasts and comparisons
- UHERO State of Hawai'i Forecasts
- Resource capital costs
- Demand response data inputs

RELIABILITY CRITERIA

Adequacy of Supply

Every year, we file an Adequacy of Supply (AOS) report. This report indicates how the generation capacity on each island's power grid is able to meet all reasonably expected demand as well as provide a reasonable reserve to meet emergencies. The AOS for the island of O'ahu incorporates a Loss-of-Load Probability (LOLP) of, at most, one outage day every 4½ years in its overall capacity planning criteria.

Another commonly used planning metric for designing a system to meet the adequacy of supply requirements is "reserve margin". For the December 2016 updated PSIP, the production modeling teams assumed a minimum 30% planning reserve margin for generation on Maui and Hawai'i Island. Because of their smaller sizes, the islands of Lana'i and Moloka'i do not have a reserve margin reliability criteria, but plan for sufficient generating capacity to serve the system demand in the event of a loss of the largest unit or a unit on maintenance.

The planning reserve margin for O'ahu was assumed to be a minimum of 45% to approximate the LOLP guideline of one outage day every 4½ years for O'ahu. O'ahu's proxy 45% reserve margin threshold for long-term modeling purposes was estimated using LOLP analysis from Hawaiian Electric's 2007 to 2016 AOS reports. The reserve margin at the point where capacity would be needed according to the LOLP guideline was determined for many situations. On average, capacity needed to be added when the reserve margin fell to 45%.

The benefit of a using reserve margin as a proxy for the actual LOLP guideline is that resource optimizations for long-term plans can be performed relatively quickly. Reserve margin calculations are relatively simple while LOLP calculations are very complex. We would analyze LOLP to determine when adequacy of supply in the near-term and to support applications for approval to add new, firm capacity.

Reserve margin calculations are deterministic in that the reserve margin for a system is calculated from discrete additions and subtractions of capacity. Firm and variable generation resources, as well as other limited run-time options (such as demand response and energy storage), were assumed to contribute capacity value to fulfill the reserve margin targets.

These thresholds use this formula to calculate the percent criteria for reserve margin:

The utility will maintain a minimum XX% Reserve Margin (F_{RM}) over the annual system peak.

$$\frac{\sum_{i=1}^{N} N_i + L_{QC} - (L_{Peak} - L_{DR})}{(L_{Peak} - L_{DR})} \geq F_{RM}$$

Where:

- F_{RM} is the Reserve Margin.
- N_i is the normal net capability of all firm units.
- L_{DR} is the amount of interruptible load available and measureable for the interruption for the entire period of the expected capacity shortfall.
- L_{QC} is the estimated capacity value of grid scale variable renewable and stored energy generation on the system.
- L_{Peak} is the forecasted annual system peak load.

As the systems evolve, the target reserve margin and capacity planning criteria will be periodically evaluated to ensure resource adequacy and supply, with consideration of the resource risk based historical performance of the types of resources providing the capacity. A search of capacity planning studies resulted in numerous papers and issues that are continuing to be studied in many different jurisdictions. One example from a study in New England[1] stated the following when planning for system adequacy:

> Energy storage has the capacity to change the load shape and reduce LOLE, but in systems with very high penetration of variable renewable energy and large-scale storage, a new framework may be required to ensure system adequacy and to credit those system components with their capacity value in a way that is clear, fair and effective. Energy storage systems obviously do not provide net energy, and only provide capacity value when they are in the presence of generators.
>
> In power systems which include very high wind penetration (Above 50%) or similar penetrations of other variable, renewable energy, system adequacy calculations may need to take a different form.[2]

Our island systems are at theses planning thresholds and beyond to achieve a 100% renewable future, and will need to evolve with best practices for capacity and resource planning as they continue to meet changing needs.

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[1] Letson, Frederick. (2015). *Wind Power Capacity Value Metrics and Variability: A Study in New England*; http://scholarworks.umass.edu/dissertations_2/474/.

[2] *ibid.*, at 129.

Capacity Value of Variable Generation, Storage, and Demand Response

Evaluating the potential to remove firm capacity generators from service—or retire them—as new resources become available must consider both reliability and adequacy of supply. Adequacy of supply evaluates whether sufficient energy capacity exists to serve the forecast demand. This evaluation must reflect the difference between conventional fossil generation and new resources.

Wind and solar cannot be scheduled to operate, as their output is variable and dependent upon availability of the resource. Determining variable resource capacity value (contribution to adequate energy supply) with a high level of confidence is a considerable challenge. Demand Response and storage differ from historical generators in being finite energy resources—the capacity is available for a specific duration beyond which it cannot be relied upon to provide energy.

An accurate determination of the capacity value of these new types of resources is critical to ensure that customer demand can be reliably met with the anticipated mix of new resources. This consideration is particularly important for the autonomous island systems in Hawaiʻi as the resources are limited to those available within each island's service area.

Capacity Value of Wind Generation

The capacity value of existing and future wind resources is determined using a statistical correlation of wind output during the peak hour of each day. A 90%probability or confidence level was used to estimate the capacity value towards capacity planning. The peak demand hour was used for evaluation of historical data. In the future, additional assessments will consider a four-hour peak period to ensure adequacy of supply for the shoulder periods.

The 90% confidence level was based on a consideration of the performance of Hawaiian Electric's firm capacity units. For example, the recorded Equivalent Forced Outage Rate (Demand) (EFORd)[3] was 10.2% in 2015. Between 2009 and 2014, the value ranged from a low of 3.4% (2013) to a high of 5.9% (2014).[4] A simple unweighted average of 2009–2015 EFORd would yield 5.1%. In the probability analysis, a higher confidence level would result in a lower capacity value. Using a 95% confidence level (approximately corresponding to the simple unweighted average of 2009–2015 EFORd), the capacity value of wind would be zero. A 90% confidence level (approximately corresponding to the worst EFORd year) still resulted in a wind capacity value of zero.

[3] EFORd weights forced outages more heavily during periods when demand is high since that is when capacity is needed the most. Maui Electric and Hawaiʻi Electric Light do not use the EFORd metric.

[4] Hawaiian Electric's 2016 Adequacy of Supply, filed on January 29, 2016.

Similar confidence levels have been reviewed at other jurisdictions (such as Southwest Power Pool and Bonneville Power Administration).[5]

The capacity value of wind at each facility is based on the daily historical availability of the wind resource to serve demand during the peak periods when capacity is needed. This historical valuation was applied to the future, including for new resources, as an approximation. The contribution would be reassessed upon actual installation based on the wind profile and production of the specific site and equipment, and its correlation to future demand profiles (the relationship anticipated to change over time).

Currently, there are no wind facilities on Lana‘i and Moloka‘i. Historical data would be required to establish the capacity value of a wind facility developed on these islands. It should be noted that because of varying wind regimes, the established wind capacity value differs on O‘ahu, Maui, and Hawai‘i Island.

Hawaiian Electric Capacity Value of Wind. Based on an examination of historical available wind capacity during the peak period hours, the two existing wind facilities (30 MW Kahuku Wind and 69 MW Kawailoa Wind) do not contribute to capacity planning. There was a poor correlation (less than 90% confidence level) between wind output and peak period hours. Capacity contribution from future resources would be reassessed upon actual installation based on the wind profile and production of the specific site and equipment. In addition, correlating to future demand peak periods may change the resulting capacity value.

Maui Electric Capacity Value of Wind. Based on historical examination of available wind capacity during the peak period hours, the aggregate capacity planning value of the three existing wind facilities (30 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, and 21 MW Auwahi Wind Energy) is about 2.8 MW.

For PSIP modeling, the capacity value of future Maui wind facilities is 3.9% of the facility's nameplate value. This is an approximation. The contribution would be reassessed upon actual installation based on the wind profile and production of the specific site and equipment. As with Hawaiian Electric, correlating to future demand peak periods may change the resulting capacity value.

Hawai‘i Electric Light Capacity Value of Wind and Run of River Hydroelectric. Based on an historical examination of available wind capacity during the peak period hours, the aggregate capacity planning value of the two existing wind facilities (20.5 MW Tawhiri wind and 10.56 MW Hawi Renewable Development wind) is about 3.7 MW. Using this same methodology, the capacity value of the hydroelectric facilities is about 1 MW.

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[5] J. Rogers and K. Porter, (2012). Summary of Timer Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States. www.nrel.gov/docs/fy12osti/54338.pdf

For PSIP modeling, the capacity value of future Hawai'i Island wind facilities is 12% of the facility's nameplate value, and the capacity value of hydroelectric facilities is 6% of the facility's nameplate value This is an approximation. The contribution would be reassessed upon actual installation based on the wind profile and production of the specific site and equipment. Again, correlating to future demand peak periods may change the resulting capacity value.

Capacity Value of Solar Generation

The approach to valuating the capacity value of solar is the same as used for the variable wind and hydro. Thus capacity value of solar generation is highly dependent on correlating to peak periods. Using the same capacity valuation methodology as for wind and hydroelectric resources, based on historical peak period hours, the capacity value of existing and future gird-scale PV and DG-PV is 0. This result is driven by the fact that variable PV does not produce during the peak evening period after the sun has set.

If a capacity valuation methodology is used, changes in the load shape from DR programs and energy storage are accounted for (as an example, DR programs and energy storage move the demands from evening periods into the midday). In that case, the capacity value of solar generation could be nonzero. In the E3 methodology, the capacity value of solar depends on the hour of the day. The capacity value is highest during the midday hours and zero during the evening peak. Applying this methodology may also change the capacity value of wind and hydroelectric resources.

The planning reserve margin (PRM) analysis was performed by E3; it is described in Appendix C: Analysis Methods and Models and in Appendix P: Consultant Report.

Capacity Value of Demand Response

The estimated megawatt potential from various programs is included in PSIP capacity planning based on updated program potential from March 2016. These programs include the Residential and Small Business Direct Load Control, Commercial and Industrial Direct Load Control, Customer Firm Generation, and Time-of-Use.

Required Regulating Reserve

General Electric (GE), working under a contract with the Hawai'i Natural Energy Institute (HNEI)[6], developed a formula for determining the amount of regulating reserve necessary to maintain the minute-to-minute balance between supply and demand on the O'ahu grid. The formula is:

> Required regulating reserve amount equals the sum of:
>
> Approximately 1 MW regulating reserve for each 1 MW of delivered wind and PV generation up to 18% of nameplate capacity of wind and PV during daytime the hours of 7 AM to 6 PM; plus
>
> 1 MW regulating reserve for each 1 MW of delivered wind and PV generation up to 23% of nameplate capacity during the hours of 6 PM to 7 AM

GE developed the formula by converting the hourly MW reserve requirements from previous studies into an hourly reserve requirement as a percent of the total online renewable capacity. The reserves represent the regulating reserve portion of the total reserve requirement only after taking into account quick-start reserve capability on O'ahu provided by existing gas-turbine and reciprocating engines (CIP CT-1, Airport DSG, Waiau 9, and Waiau 10).

Electric Power Systems (EPS) developed a formula for Lana'i, Moloka'i, and Hawai'i Island. The formulas are based on resources whose outputs respond directly to energy source availability, without mitigation for smoothing or ramp control. That formula is:

> Required regulating reserve amount equals the sum of:
>
> 1 MW regulating reserve for each 1 MW of delivered wind generation up to 50% of nameplate capacity of wind, plus
>
> 1 MW regulating reserve for each 1 MW delivered DG-PV generation up to 20% of nameplate capacity of DG-PV, plus
>
> 1 MW regulating reserve for each 1 MW of delivered utility-scale PV generation up to 60% of nameplate capacity of utility-scale PV

[6] Refer to HNEI study material http://www.hnei.hawaii.edu/projects/hawaii-rps-study and http://www.hnei.hawaii.edu/projects/hawaii-solar-integration for more information.

The amount of regulating reserve required on Maui to regulate frequency because of the variability of output from variable generation resources is currently determined from a formula derived in the December 19, 2012 Hawai'i Solar Integration Study prepared by GE for the National Renewable Energy Laboratory, HNEI, Hawaiian Electric Company and Maui Electric Company. That formula is:

The greater of 6 MW, or

1 MW regulating reserve for each 1 MW of delivered wind and solar power up to a maximum of 27 MW, less 10 MW for the KWP II BESS. (Solar power includes behind-the-meter and grid-side PV.)

Maui Electric plans to transition to the EPS regulating reserve formula. But first, Maui Electric must determine the effects on costs and curtailment with the addition of 40 MW of internal combustion engines, a 20 MW regulating reserve BESS, a 20 MW contingency reserve BESS, and the decommissioning of Kahului Power Plant.

UTILITY COST OF CAPITAL AND FINANCIAL ASSUMPTIONS

The Hawaiian Electric Companies finance their investments through two main sources of capital: debt (borrowed money) or equity (invested money). In both cases, we pay a certain rate of return for the use of this money. This rate of return is our *Cost of Capital*.

Table J-1 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

Capital Source	Weight	Rate
Short Term Debt	3.0%	4.0%
Long Term Debt (Taxable Debt)	39.0%	7.0%
Hybrids	0.0%	6.5%
Preferred Stock	1.0%	6.5%
Common Stock	57.0%	11.0%

Composite Weighted Average 9.185%
After-Tax Composite Weighted Average 8.076%

Table J-1. Utility Cost of Capital

FUEL PRICE FORECASTS AND AVAILABILITY

The potential cost of producing electricity depends, in part, on the cost of fuels utilized in the generation of power. The cost of different fuels over the next 20-plus years are forecast and used in the PSIP analyses. The Companies use the following different types of fuels in our company-owned generators:

- Low Sulfur Fuel Oil (LSFO). A residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content.
- No.2 Diesel Oil
- Ultra-Low Sulfur Diesel (ULSD)
- Naphtha
- Medium Sulfur Fuel Oil (MSFO containing less than 2% sulfur; also called ISO-Industrial Fuel Oil)
- Biodiesel

Petroleum-Based Fuels

The petroleum-based fuel forecasts reflect forecast data for Imported Crude Oil and Gross Domestic Product (GDP) Chain-Type Price Index from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) Early Release report published in May 2016. Historical prices for crude oil are EIA publication table data for the Monthly Energy Review and macroeconomic data. Historical actual fuel costs incorporate taxes and certain fuel-related and fuel-handling costs including but not limited to trucking and ocean transport, petroleum inspection, and terminal fees.

The April 2015 AEO placed the price of Brent crude oil at $60 a barrel. By the end of 2015, the price had dropped to below $40 a barrel—below the 2015 AEO low economic growth case which estimated 2016 Brent crude oil at over $50 per barrel. The 2016 AEO Early Release estimated the average Brent crude oil price to be $37 a barrel in 2016, rising to $77 a barrel by 2020 as demand and supply come into balance.

In 2016, the ratio of oil to natural gas prices was approximately 2.5:1; the lowest in over ten years. The 2016 AEO Early Release projects that oil prices will begin to rise steadily over the next 25 years. Natural gas prices are projected to also grow, but more slowly based on likely improvements to extraction technologies. By 2015, oil-to-natural-gas prices are projected to increase to an approximate 4.9:1 ratio.

LNG Fuel Price Forecasts

The April 2015 AEO reported that natural gas prices dropped from $3/MMBtu to less than $2/MMBtu.

The delivered LNG fuel price forecasts include cost information for the pipeline transport, LNG liquefaction, transportation of the LNG, and transportation logistics from the Companies' Containerized LNG Supply to Hawai'i RFP. The EIA forecasts are based on Henry Hub pricing. Henry Hub, a Louisiana natural gas distribution hub and pricing point for natural gas futures contracts, trades on the New York Mercantile Exchange (NYMEX). Natural gas prices are expected to increase gradually over the next decade. The LNG price forecasts used in the PSIP attempts to account for natural gas that is sourced from British Columbia. Based on the future's market pricing and historical data, gas sourced from Alberta (AECO market) and British Columbia (Station 2 gathering point) has traded at a discount to the United States Henry Hub pricing.

For Oahu's LNG pricing curves, we applied a negative 26.5% basis to create a Station 2 equivalent Henry Hub price. For example, a $2.00/MMBtu Henry Hub price would equate to a $1.47/MMBtu Station 2 price. We then applied a 4.5% adder to the derived Station 2 price to account for shrinkage on the pipelines from the Station 2 gathering point to the liquefaction plant.

The Companies contemplates that the natural gas for its LNG will be procured under a daily or monthly index, gathered at Station 2 and transported on the Spectra Energy Westcoast Transmission T-South pipeline. T-South is a looped (multiple pipeline) system that moves gas from Station 2 to the Huntingdon/Sumas trading pool. T-South firm capacity can be procured at a rolled-in tariff rate—if capital improvements are required to increase pipeline capacity, expansion costs are borne by all users on the pipeline. Charges to use the pipeline will be at a fixed tariff CAD/GJ rate, converted to $/MMBtu. As a mature depreciating pipeline system, the general trend is towards stable long-term rates. The current rate is approximately $0.32/MMBtu.

From the Sumas hub, gas will be distributed on the Fortis regulated Coastal Transmission System (CTS) to the existing FortisBC Energy Inc. (FEI) LNG facility on Tilsbury Island in Delta, British Columbia, Canada on the Fraser River. The CTS pipeline rate is regulated under the Rate Schedule 50 (RS50) tariff in units of CAD/GJ and converted to $/MMBtu for the Hawaiian Electric contract. The FEI CTS system is designed to meet high winter peaking demand and is therefore under-utilized for a majority of the year. Therefore, if more flat non-peaking load is added, by Hawaiian Electric or other industrial demand, the general trend would be for rates to reduce. This is reflected in the RS50 rate floor which decreases as demand increases. The current tariff rate under RS50 is approximately $0.42/ MMBtu.

The LNG fuel price forecasts in Table J-2 through Table J-4 represent the total variable costs of the LNG (including the gas commodity, taxes, port fees, wharfage, stevedoring, and other ancillary delivery service charges). Table J-5 lists the total nominal LNG costs, including variable and fixed costs. Fixed costs include liquefaction, pipeline tolls (for tariff service), and shipping charges.

Hawaiian Electric Fuel Price Forecasts

$/MMBtu	Hawaiian Electric Fuel Price Forecasts					
	2016 EIA AEO Early Release					
Year	LSFO	No. 2 Diesel	ULSD	40% LSFO/ 60% ULSD	Biodiesel	LNG
2016	$6.85	$9.40	$10.32	$8.86	$29.87	n/a
2017	$9.13	$11.78	$12.76	$11.24	$32.31	n/a
2018	$11.04	$13.77	$14.82	$13.23	$34.41	n/a
2019	$13.85	$16.69	$17.81	$16.15	$37.30	n/a
2020	$15.45	$18.37	$19.55	$17.83	$39.20	n/a
2021	$16.77	$19.78	$21.01	$19.23	$40.93	$7.61
2022	$17.88	$20.97	$22.25	$20.42	$42.48	$7.77
2023	$18.76	$21.93	$23.24	$21.36	$43.76	$8.03
2024	$19.56	$22.79	$24.14	$22.22	$44.96	$8.43
2025	$20.48	$23.79	$25.17	$23.21	$46.28	$8.71
2026	$21.58	$24.96	$26.39	$24.37	$47.78	$8.31
2027	$22.60	$26.06	$27.53	$25.46	$49.23	$8.43
2028	$23.56	$27.10	$28.61	$26.50	$50.64	$8.64
2029	$24.75	$28.37	$29.93	$27.76	$52.28	$8.85
2030	$25.71	$29.42	$31.02	$28.79	$53.75	$9.03
2031	$27.09	$30.89	$32.55	$30.26	$55.62	$9.15
2032	$28.53	$32.44	$34.15	$31.80	$57.57	$9.36
2033	$30.05	$34.06	$35.83	$33.41	$59.60	$9.48
2034	$31.68	$35.80	$37.63	$35.14	$61.74	$9.64
2035	$33.02	$37.24	$39.13	$36.57	$63.66	$9.78
2036	$34.78	$39.12	$41.07	$38.43	$65.94	$9.96
2037	$36.19	$40.64	$42.65	$39.94	$67.95	$10.07
2038	$38.08	$42.64	$44.73	$41.94	$70.37	$10.19
2039	$39.77	$44.45	$46.60	$43.74	$72.63	$10.49
2040	$41.89	$46.70	$48.92	$45.97	$75.26	$10.71
2041	$43.62	$48.54	$50.83	$47.81	$77.54	$10.94
2042	$45.54	$50.59	$52.94	$49.84	$79.99	n/a
2043	$47.51	$52.67	$55.10	$51.92	$82.48	n/a
2044	$49.51	$54.80	$57.30	$54.04	$85.00	n/a
2045	$51.56	$56.97	$59.54	$56.20	$87.55	n/a

Table J-2. Hawaiian Electric Fuel Price Forecasts (nominal dollars)

Maui Electric Fuel Price Forecasts

$/MMBtu	Maui Electric Fuel Price Forecasts						
	2016 EIA AEO Early Release						
Year	MSFO	No. 2 Diesel	ULSD (Maui)	ULSD (Moloka'i)	ULSD (Lana'i)	Biodiesel	LNG
2016	$5.59	$9.52	$9.87	$11.09	$14.07	$29.87	n/a
2017	$7.55	$12.17	$12.58	$13.78	$16.79	$32.31	n/a
2018	$9.19	$14.40	$14.86	$16.05	$19.08	$34.41	n/a
2019	$11.60	$17.66	$18.20	$19.35	$22.39	$37.30	n/a
2020	$12.98	$19.53	$20.12	$21.27	$24.35	$39.20	n/a
2021	$14.10	$21.08	$21.71	$22.87	$26.00	$40.93	$9.98
2022	$15.06	$22.40	$23.06	$24.23	$27.42	$42.48	$10.18
2023	$15.81	$23.45	$24.14	$25.32	$28.56	$43.76	$10.48
2024	$16.49	$24.40	$25.12	$26.31	$29.60	$44.96	$10.92
2025	$17.28	$25.50	$26.24	$27.44	$30.79	$46.28	$11.24
2026	$18.21	$26.79	$27.57	$28.78	$32.18	$47.78	$10.89
2027	$19.09	$28.01	$28.81	$30.03	$33.49	$49.23	$11.05
2028	$19.91	$29.15	$29.98	$31.22	$34.73	$50.64	$11.30
2029	$20.92	$30.56	$31.43	$32.67	$36.24	$52.28	$11.57
2030	$21.74	$31.70	$32.60	$33.86	$37.50	$53.75	$11.79
2031	$22.92	$33.33	$34.27	$35.55	$39.25	$55.62	$11.96
2032	$24.16	$35.04	$36.02	$37.31	$41.07	$57.57	$12.22
2033	$25.45	$36.83	$37.86	$39.15	$42.99	$59.60	$12.39
2034	$26.85	$38.75	$39.83	$41.13	$45.03	$61.74	$12.60
2035	$27.99	$40.34	$41.46	$42.78	$46.76	$63.66	$12.79
2036	$29.50	$42.42	$43.59	$44.91	$48.96	$65.94	$13.02
2037	$30.70	$44.09	$45.30	$46.65	$50.77	$67.95	$13.19
2038	$32.32	$46.32	$47.58	$48.93	$53.12	$70.37	$13.36
2039	$33.77	$48.31	$49.63	$50.99	$55.25	$72.63	$13.72
2040	$35.59	$50.81	$52.18	$53.54	$57.88	$75.26	$14.00
2041	$37.07	$52.85	$54.27	$55.64	$60.05	$77.54	$14.29
2042	$38.71	$55.11	$56.59	$57.97	$62.44	$79.99	n/a
2043	$40.39	$57.42	$58.96	$60.34	$64.88	$82.48	n/a
2044	$42.11	$59.78	$61.37	$62.76	$67.37	$85.00	n/a
2045	$43.86	$62.18	$63.84	$65.23	$69.90	$87.55	n/a

Table J-3. Maui Electric Fuel Price Forecasts (nominal dollars)

Hawai‘i Electric Light Fuel Price Forecasts

$/MMBtu	Hawai‘i Electric Light Fuel Price Forecasts					
	2016 EIA AEO Early Release					
Year	MSFO	No. 2 Diesel	ULSD	Naphtha	Biodiesel	LNG
2016	$5.90	$9.98	$10.25	$11.96	$29.87	n/a
2017	$7.88	$12.55	$12.88	$14.40	$32.31	n/a
2018	$9.54	$14.70	$15.09	$16.46	$34.41	n/a
2019	$11.98	$17.86	$18.31	$19.44	$37.30	n/a
2020	$13.37	$19.68	$20.17	$21.19	$39.20	n/a
2021	$14.51	$21.19	$21.72	$22.67	$40.93	$10.20
2022	$15.48	$22.48	$23.05	$23.93	$42.48	$10.41
2023	$16.24	$23.51	$24.10	$24.94	$43.76	$10.71
2024	$16.93	$24.44	$25.05	$25.87	$44.96	$11.16
2025	$17.73	$25.51	$26.15	$26.92	$46.28	$11.48
2026	$18.68	$26.78	$27.45	$28.16	$47.78	$11.14
2027	$19.57	$27.97	$28.66	$29.33	$49.23	$11.30
2028	$20.40	$29.09	$29.81	$30.44	$50.64	$11.56
2029	$21.43	$30.46	$31.21	$31.78	$52.28	$11.83
2030	$22.26	$31.59	$32.36	$32.90	$53.75	$12.05
2031	$23.46	$33.18	$33.99	$34.45	$55.62	$12.23
2032	$24.71	$34.85	$35.70	$36.08	$57.57	$12.50
2033	$26.03	$36.60	$37.49	$37.79	$59.60	$12.67
2034	$27.44	$38.47	$39.41	$39.62	$61.74	$12.89
2035	$28.60	$40.03	$41.00	$41.15	$63.66	$13.09
2036	$30.13	$42.05	$43.07	$43.12	$65.94	$13.32
2037	$31.35	$43.69	$44.75	$44.73	$67.95	$13.49
2038	$32.99	$45.86	$46.97	$46.83	$70.37	$13.68
2039	$34.46	$47.80	$48.96	$48.73	$72.63	$14.04
2040	$36.30	$50.23	$51.45	$51.08	$75.26	$14.32
2041	$37.80	$52.22	$53.48	$53.01	$77.54	$14.62
2042	$39.47	$54.43	$55.74	$55.15	$79.99	n/a
2043	$41.17	$56.68	$58.04	$57.33	$82.48	n/a
2044	$42.91	$58.97	$60.39	$59.56	$85.00	n/a
2045	$44.69	$61.31	$62.79	$61.82	$87.55	n/a

Table J-4. Hawai‘i Electric Light Fuel Price Forecasts (nominal dollars)

LNG Total Cost Price Forecasts

2016 EIA Total Cost Henry Hub Spot Prices for Natural Gas

$/MMBtu	2016 EIA Total Cost Henry Hub Spot Prices for Natural Gas		
Year	*O'ahu Total Cost*	*Maui Total Cost*	*Hawai'i Island Total Cost*
2021	$14.76	$17.09	$17.31
2022	$15.01	$17.38	$17.61
2023	$15.35	$17.76	$17.99
2024	$15.83	$18.28	$18.52
2025	$16.20	$18.69	$18.93
2026	$15.88	$18.42	$18.67
2027	$16.09	$18.67	$18.92
2028	$16.39	$19.02	$19.27
2029	$16.70	$19.37	$19.63
2030	$16.96	$19.68	$19.95
2031	$17.18	$19.95	$20.22
2032	$17.49	$20.31	$20.59
2033	$17.71	$20.57	$20.86
2034	$17.97	$20.89	$21.18
2035	$18.22	$21.19	$21.48
2036	$18.50	$21.52	$21.82
2037	$18.72	$21.80	$22.10
2038	$18.95	$22.08	$22.39
2039	$19.36	$22.55	$22.86
2040	$19.69	$22.94	$23.26
2041	$20.05	$23.35	$23.68

Table J-5. 2016 EIA Total Cost Henry Hub Spot Prices for Natural Gas (reference case—nominal dollars)

Hawaiian Electric Fuel Price Forecast Trends

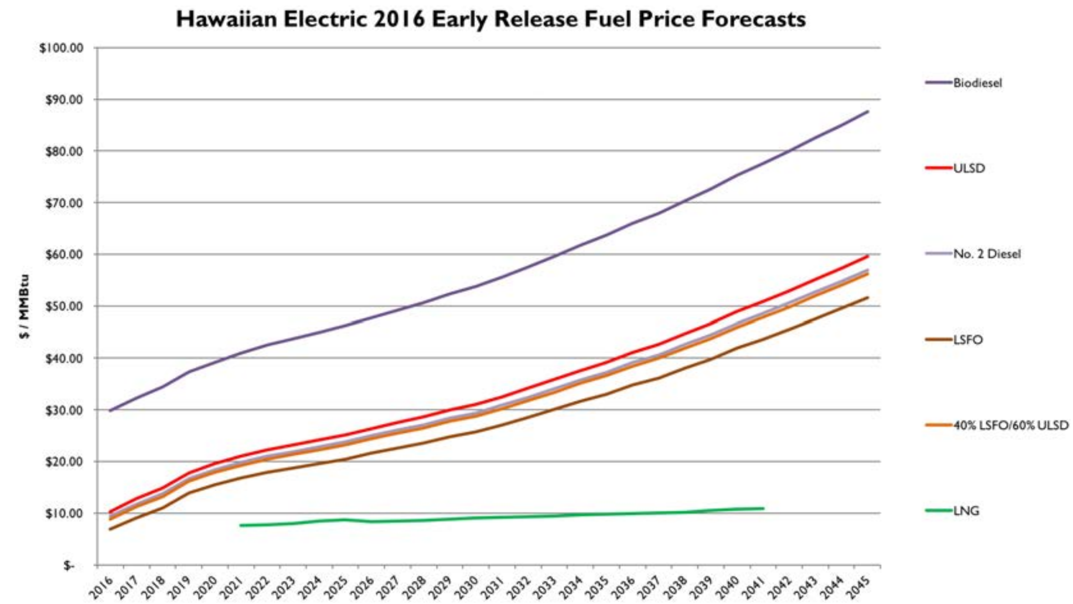


Figure J-1. Hawaiian Electric Fuel Price Forecast Trends (nominal dollars)

Maui Electric Fuel Price Forecast Trends

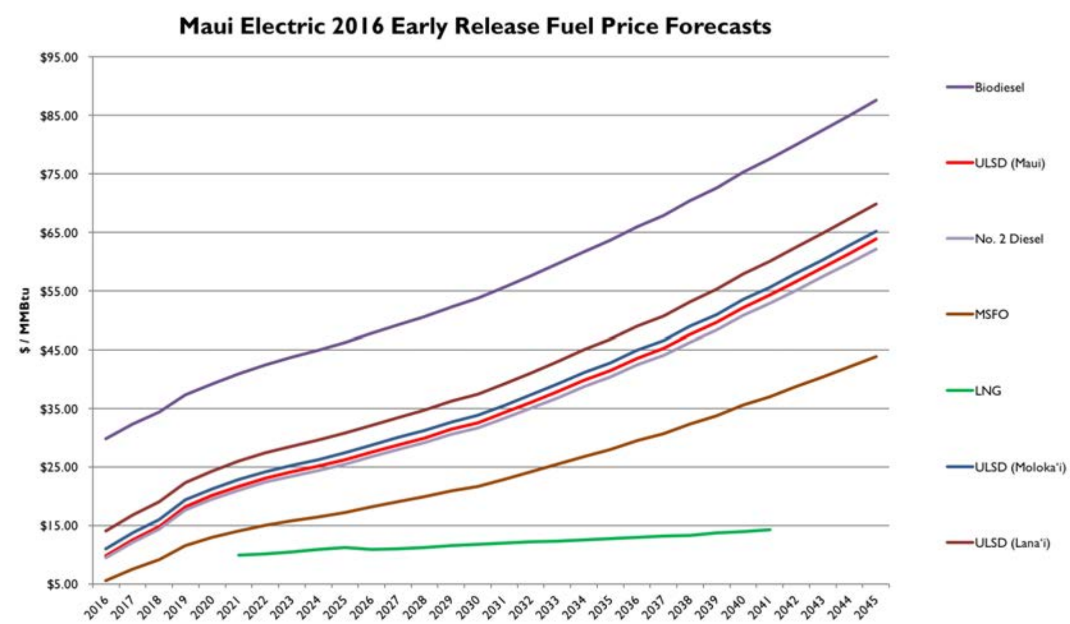


Figure J-2. Maui Electric Fuel Price Forecast Trends (nominal dollars)

Hawai‘i Electric Light Fuel Price Forecast Trends

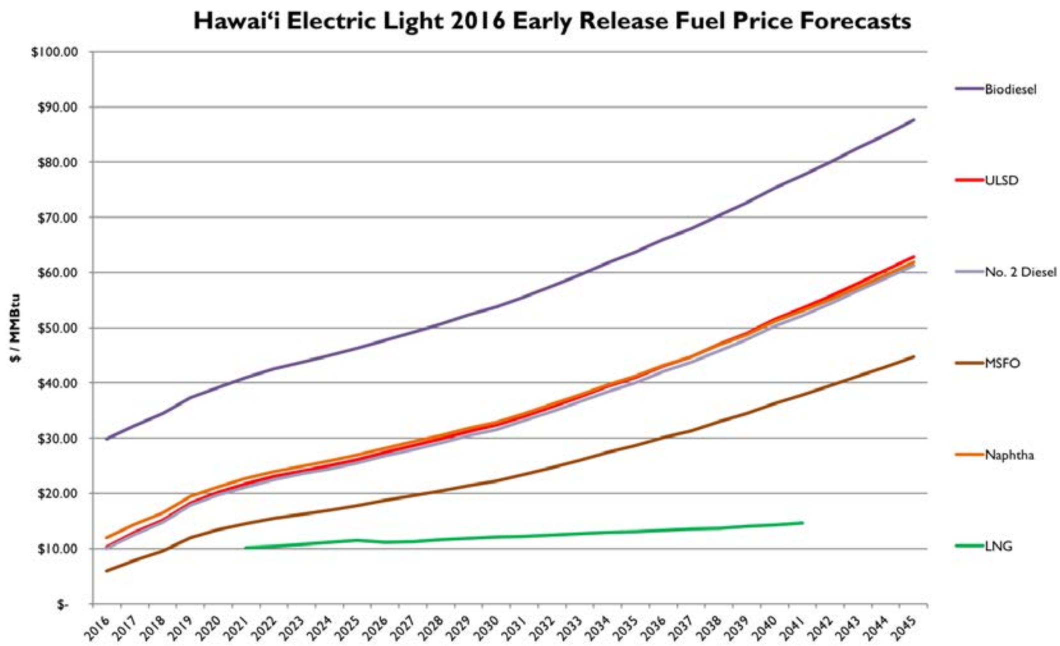


Figure J-3. Hawai‘i Electric Light Fuel Price Forecast Trends (nominal dollars)

ENERGY SALES AND PEAK DEMAND FORECAST

The purpose of the load (or peak demand) and sales (energy) forecasts in a planning study is to provide the energy requirements (in GWh) and peak demands (in MW) that must be served by the Company during the planning study period. Forecasts of energy requirements and peak demand must take into account economic trends and projections and changing end uses, including the emergence of new technologies.

The forecast developed for the February 2016 interim filing was one of the key assumptions that fed into the beginning of an iterative process used to determine varying levels of customer adoption of DER and participation in DR programs to achieve system optimization. As described in Appendix C: Analysis Methods and Models, the PSIP optimization process involves iterative cycles that analyze DER, DR and utility-scale resources in production simulation and financial rate models toward selecting a preferred plan. Forecast sensitivities were developed as a result of varying the levels of DER and DESS adoption.

These sensitivities and iterations led to the forecast used for this December 2016 update, which differs from the forecasts in the February 2016 and April 2016 updates in the amount of customer adoption of DER. Although DR and behind the meter energy storage (DESS) projections and their influences are modeled in this December 2016 PSIP update, the sales and peak demand forecasts do not reflect any influence from DR programs, DESS, or modification of DER operation in response to grid reliability needs. Subsequent steps in the analysis process address these impacts. For instance, DR load shifting programs result in changes to customer load shape and therefore peak load at certain times. There is also a possibility that output of DER may be reduced in response to a system excess generation condition, which would be identified in subsequent analysis steps as well.

Sales and Peak Demand Projections Methodology

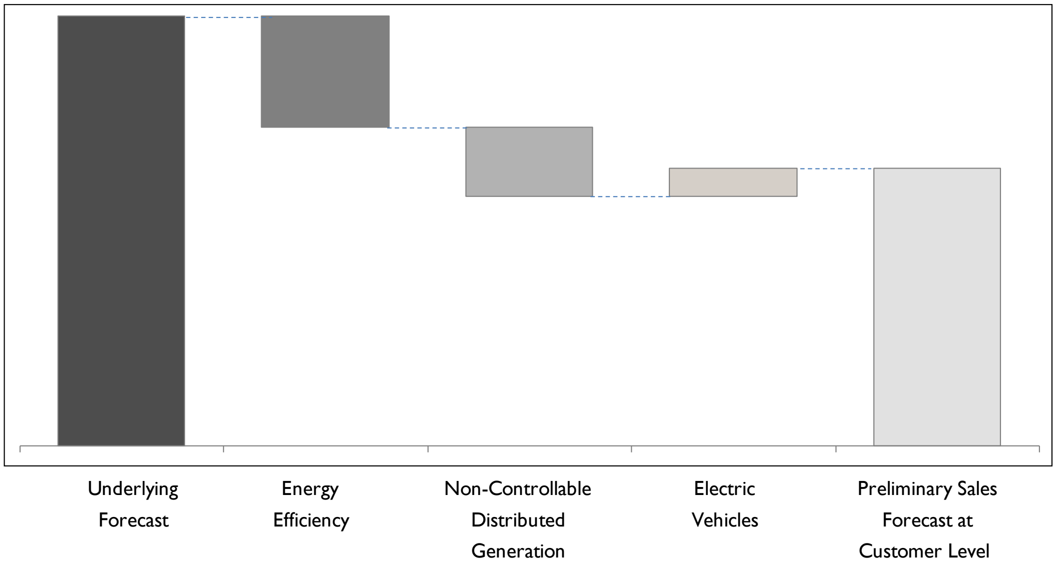
The Company develops sales and peak demand forecasts on an annual basis and utilizes the latest information available at the time the forecast is prepared. The sales and peak forecasts adopted in May 2015 for all islands were used as the starting point for the sales and peak demand analyses, as they were the most currently available forecasts. As part of the first iteration in the PSIP optimization process the customer-sited distributed generation (DG-PV) projections in the May 2015 forecast were updated to reflect modifications to the existing Company tariffs identified in Decision and Order No. 33258 in Docket No. 2014-0192 received in October 2015 for use in the February 2016 interim filing. This order approved revised interconnection standards, the closing of the Net Energy Metering program and new options for customers aimed at continuing the growth of rooftop solar while ensuring safe and reliable service. Subsequent to the February 2016 Interim filing, the DG-PV forecasts have been updated with each cycle of the iterative process described in Appendix C.

The methodology for deriving net peak demand and energy requirements to be served by the Company begins with the identification of key factors that affect load growth. These factors include the economic outlook, analysis of existing and proposed large customer loads, and impacts of customer-sited technologies such as energy efficiency measures and DG-PV. Impacts from emerging technologies such as electric vehicles (EV) and storage are also evaluated given their significant potential impact on future demand for energy.

The Company reached out to Hawai‘i Energy to assist with the development of alternative energy efficiency forecasts to better address potential uncertainties. The Company received future energy efficiency program estimates from Hawai‘i Energy and has been collaborating with Hawai‘i Energy to understand how best to incorporate their projections into the broader long-term forecast. At this time, it is a work in progress that was not available to support the December 2016 PSIP update. However, the Company will use information provided by Hawai‘i Energy to inform future forecasts and as part of a larger iterative cycle, the PSIP analyses could be incorporated into the ongoing Energy Efficiency Technical Working Group process.

Energy Sales Forecast

In general, the underlying economy driven sales forecast (“underlying forecast”) is first derived by using econometric methods and historical sales data, excluding impacts from energy efficiency measures and DG. This methodology captures the impact of economic growth, which is typically the most influential factor when forecasting long-term changes in sales and peak demand. Estimates of impacts from energy efficiency measures, DG installed through the Company’s tariffed programs and electric vehicles (referred to as “layers”) are then incorporated to adjust the underlying forecast to arrive at a preliminary sales forecast. This methodology is illustrated below in the following chart (Figure J-4). The forecast is then used to drive the DER optimization routine.



Sales forecast will be further modified by future controllable DG export product which will be discussed in later chapters

Figure J-4. Illustrative Waterfall Methodology for Developing the Sales Forecast

The forecasted sales used to be served by each operating company through the study period expressed at the customer level is shown in Figure J-5 through Figure J-9. This forecast depicts the starting point with market DG-PV forecasts used in the December 2016 PSIP update analyses. Data for the sales forecast projections are detailed in Table J-7 through Table J-11.

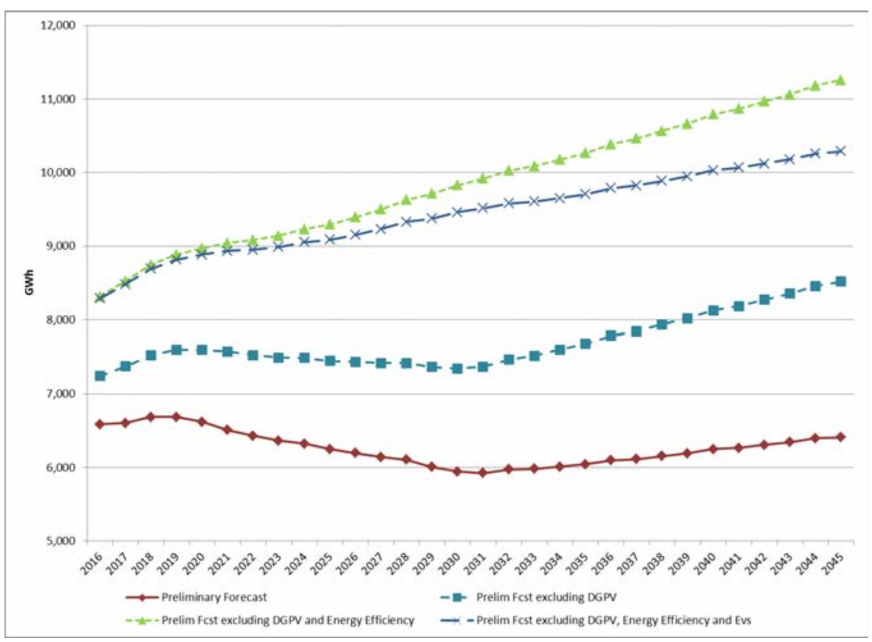


Figure J-5. O‘ahu Customer Level Sales Forecast

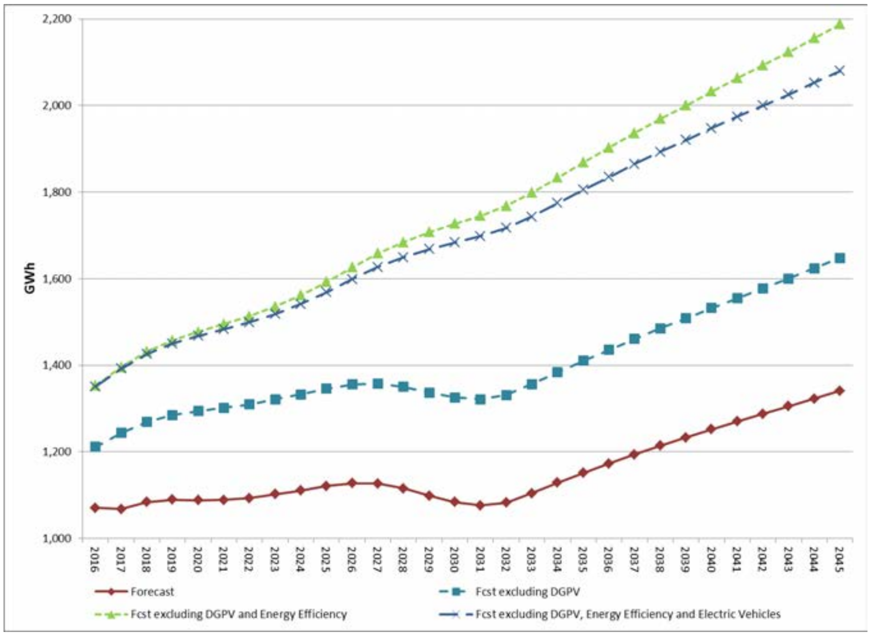


Figure J-6. Maui Island Customer Level Sales Forecast

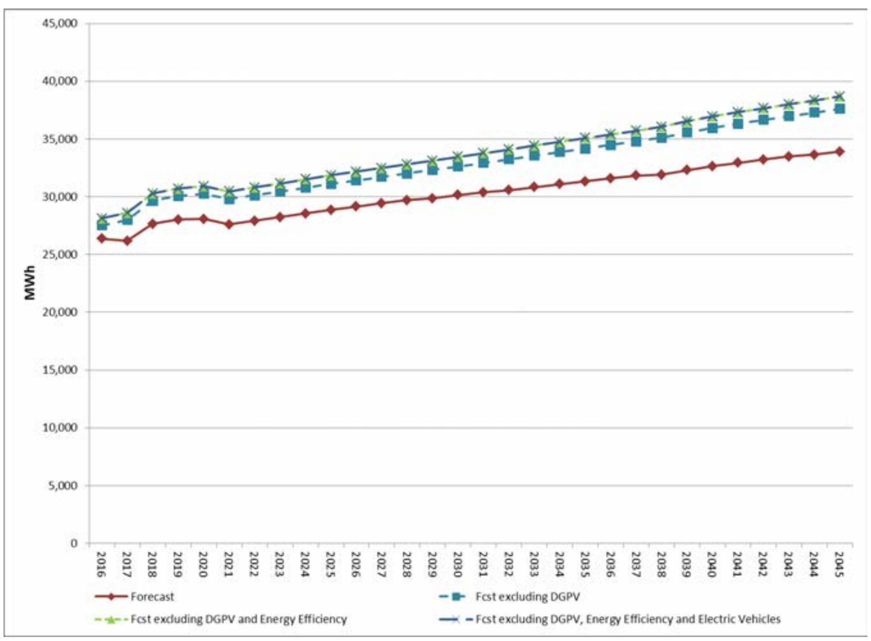


Figure J-7. Lana'i Customer Level Sales Forecast

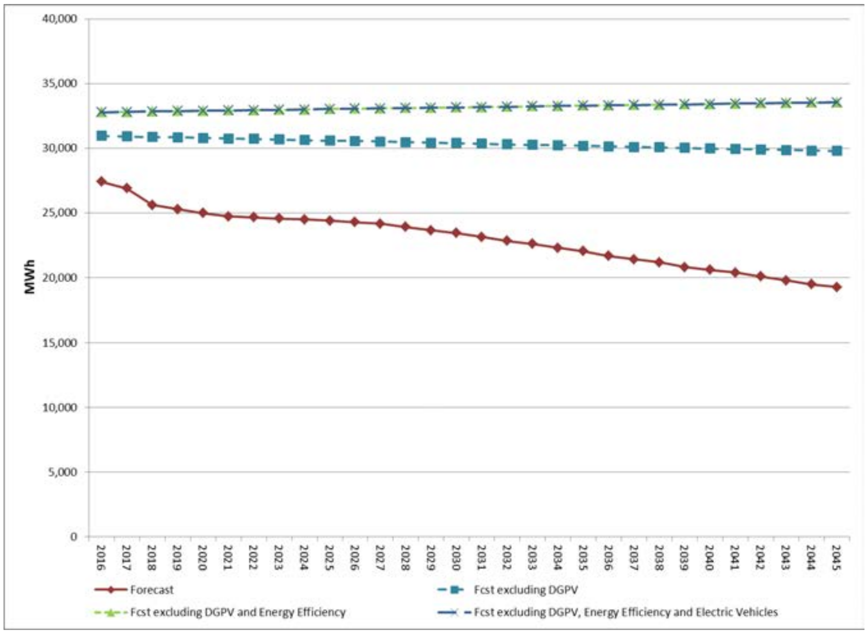


Figure J-8. Moloka'i Customer Level Sales Forecast

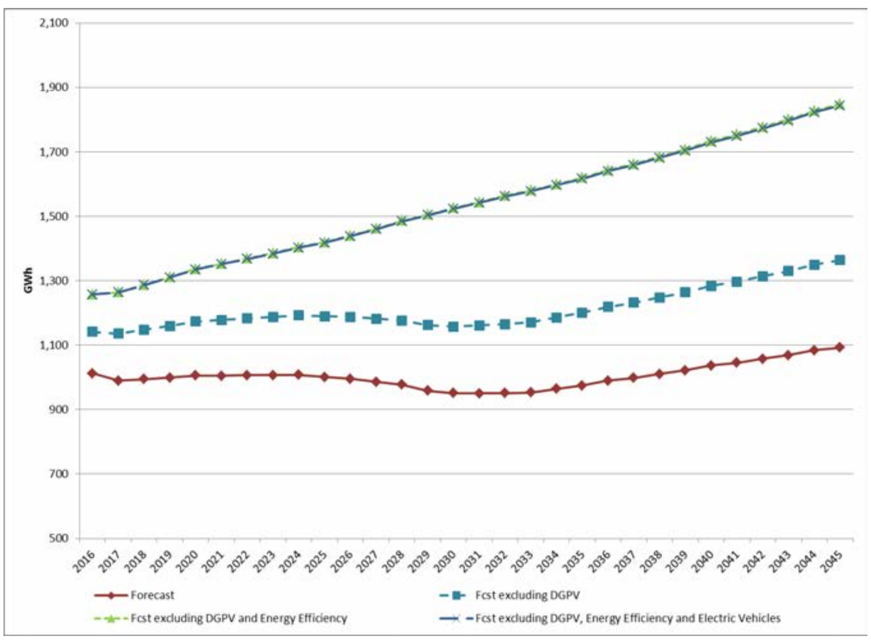


Figure J-9. Hawai'i Island Customer Level Sales Forecast

DG-PV Energy Sales Forecasts

Table J-6 depicts the difference between our initial input assumptions and those assumed by Ulupono as a result of their suggested changes. Note that these Ulupono amounts are projected, and not necessarily the results of the revised NREL resource potential study.

Resources (MW)	Hawaiian Electric	Ulupono (Dr. Fripp)	Maui Electric	Hawai‘i Electric Light
Onshore Grid-Scale PV	2,756	6,583	783	30,484
Onshore Market DG-PV	1,308	n/a	206	184
Onshore High DG-PV	2,101	3,022	450	456
Onshore Grid-Scale Wind	162	2,680	840	3,532
Offshore Grid-Scale Wind	800	800	n/a	n/a

Table J-6. Renewable Energy Resource Potential

Underlying Forecast. The underlying forecast incorporates projections for key drivers of the economy prepared by the University of Hawai‘i Economic Research Organization (UHERO) in April 2015 such as job counts, personal income and resident population. Electricity price and weather variables are also included in the models.

Energy Efficiency. The preliminary projections for impacts associated with energy efficiency measures over the next five to ten years were assumed to be consistent with historical average annual impacts achieved by the Public Benefits Fund Administrator, Hawai‘i Energy. In addition to the impacts from Hawai‘i Energy's programs, changes to building and manufacturing codes and standards would be integrated into the marketplace over time contributing to market transformation. Collectively, these changes would support energy efficiency impacts growing at a faster pace in order to meet the longer term energy efficiency goal in 2030 (expressed in GWh). This pace is identified in the framework that governs the achievement of Energy Efficiency Portfolio Standards (EEPS) in the State of Hawai‘i as prescribed in Hawai‘i Revised Statutes § 269-96, and set by the Commission in Decision and Order No. 30089 in Docket No. 2010-0037. It was assumed the 30% sales reduction goal would continue beyond 2030. These projections did not consider participation in DR programs. DR program participation is taken into consideration in later steps of the analysis process.

To determine the peak demand savings from energy efficiency, an average annual ratio between historical efficiency sales and peak impacts was applied to the projected annual energy impacts.

There is a significant uncertainty regarding the degree customers will engage in the adoption of energy efficiency measures, building practices and participation in DR programs. This will have a direct impact on projected sales and peak demand levels. If customer adoption is lower than projected, then demand for energy could exceed the forecasted levels and conversely, higher than projected would lower customer demand for energy. Over the 30-year planning period, participation may be higher or lower than the forecast depending on factors such as customer preferences, general economic conditions and availability of affordable technology. Although all future unknowns cannot be identified, the Company will work together with Hawaiʻi Energy to develop alternative energy efficiency forecasts to better understand and address potential uncertainties.

Distributed Generation. In support of the December 2016 updated PSIP, an iteration of the DER optimization cycle was completed. The projections for impacts associated with distributed generation photovoltaic (DG-PV) systems installed under the Company's tariffed programs (legacy NEM, SIA, grid-supply to cap, self-supply and potential future grid-supply) were developed separately by program for residential and commercial customers and aggregated into an overall forecast for DG-PV systems. For the self-supply portion of the forecasts, residential and small commercial DG-PV systems were paired with distributed energy storage systems (DESS). The paired DG-PV and DESS system sizes were based on optimal customer economics determined by maximizing the NPV of the customer investment via the Boston Consulting Group ("BCG") customer adoption model. Residential and some small commercial load shapes on average have relatively lower daytime load and higher evening loads. Therefore in a self-supply program the use of a DESS allows them to self-generate a much larger portion of their energy needs than they would be able to otherwise if their PV system size was limited to not exceed their daytime load. Larger commercial customers on average have larger daytime loads that enable them to benefit significantly from a self-supply program without the need to invest in DESS. Additional stand-alone DESS, not necessarily paired with PV, were projected to participate in Demand Response programs since it is possible for customers and the grid to benefit from stand-alone DESS as well.

In the near term (through 2018) assumptions based on recent historical activity and known projects were made regarding the timing of system installations associated with the remaining applications in the legacy NEM queue, Customer Grid Supply up to the cap, and near term SIA projections. For additional future quantities of self-supply, SIA and potential future grid-supply DG-PV systems, the Company used a customer adoption model developed by BCG. The model examines the relationship between economics and adoption of DG-PV and DG-PV with DESS based on payback time, net present value (NPV) and internal rate of return (IRR) from the customer's perspective. For the potential future grid-supply program, it was assumed that energy exported to the grid would be compensated at utility-scale PV LCOE.

Figure J-10 through Figure J-14 depicts the market DG-PV forecasts for Oʻahu, Hawaiʻi Island, Maui, Lanai, and Molokai developed to support the December 2016 PSIP update. Table J-15 through Table J-19 depicts the customer self-supply DESS forecasts for the respective islands. Data corresponding to the DESS forecast figures are detailed in Table J-27 through Table J-31.

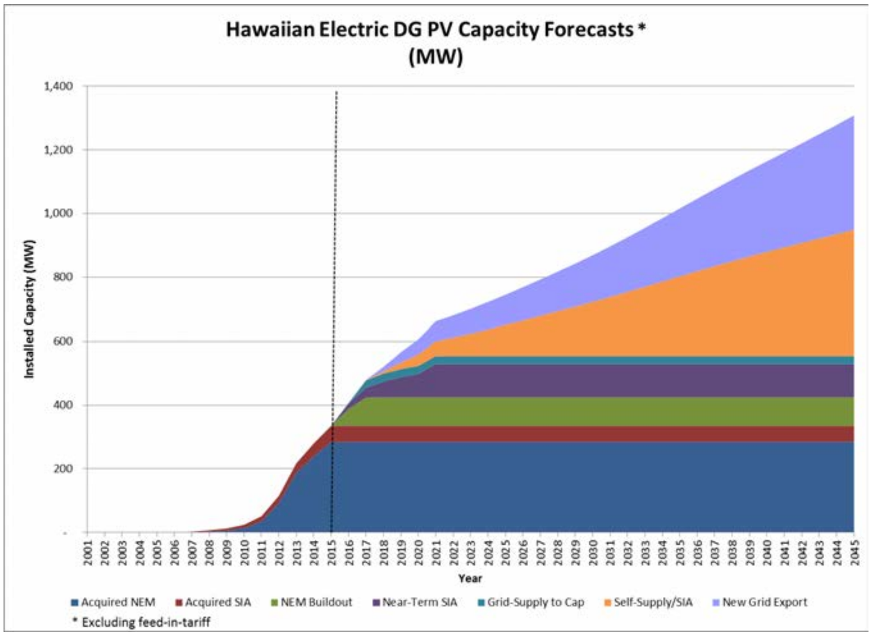


Figure J-10. O'ahu Market DG-PV Capacity Forecasts

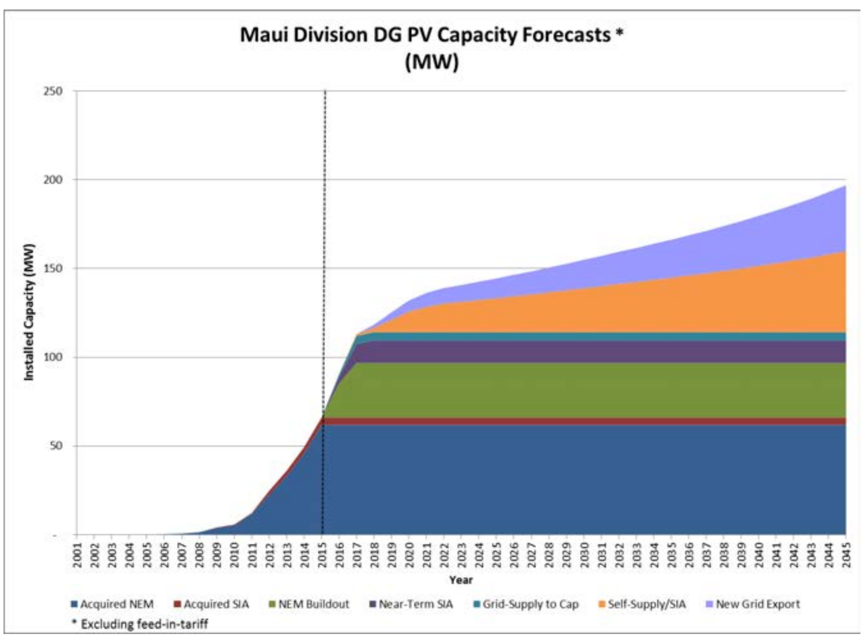


Figure J-11. Maui Island Market DG-PV Capacity Forecasts

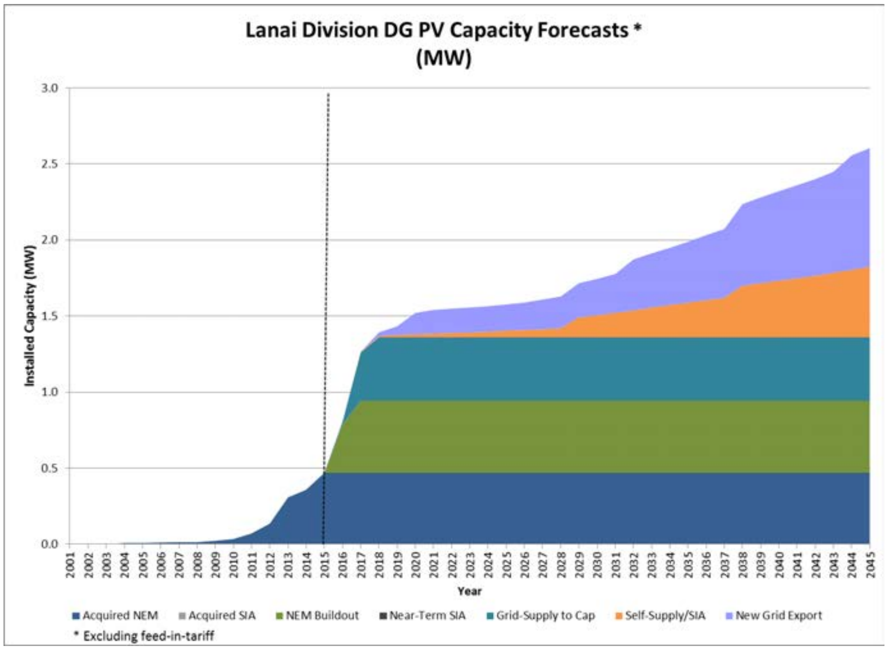


Figure J-12. Lana'i Market DG-PV Capacity Forecasts

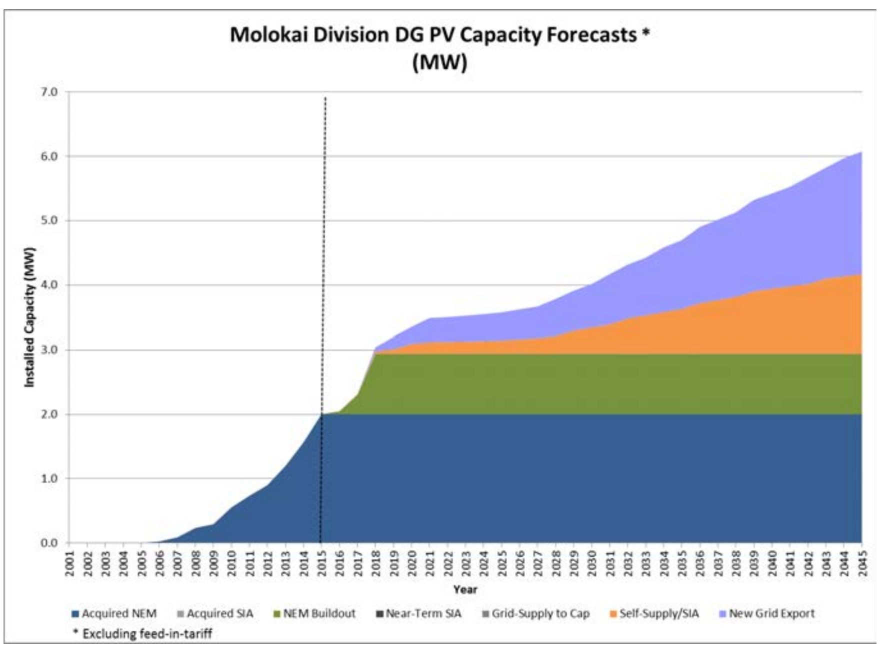


Figure J-13. Moloka'i Market DG-PV Capacity Forecasts

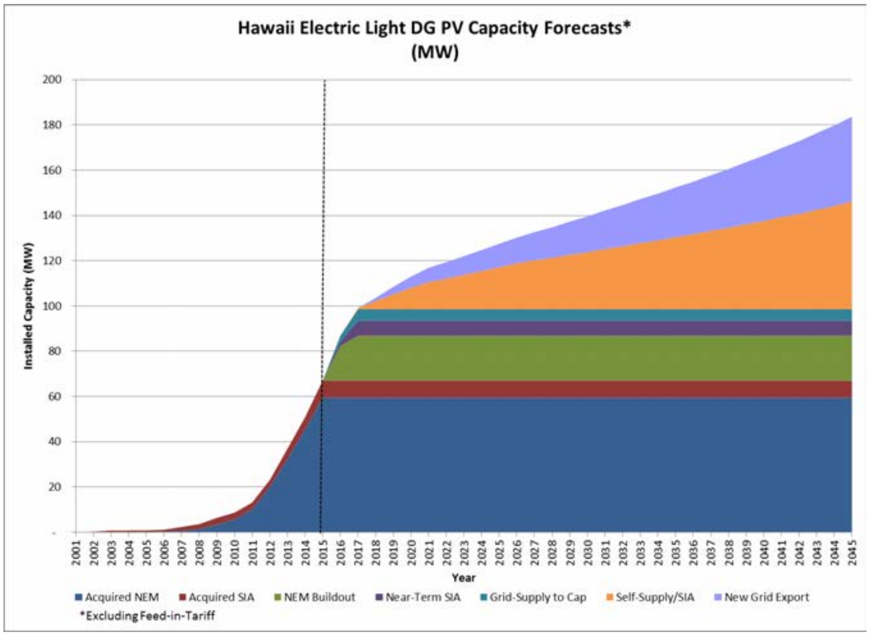


Figure J-14. Hawai'i Island Market DG-PV Capacity Forecasts

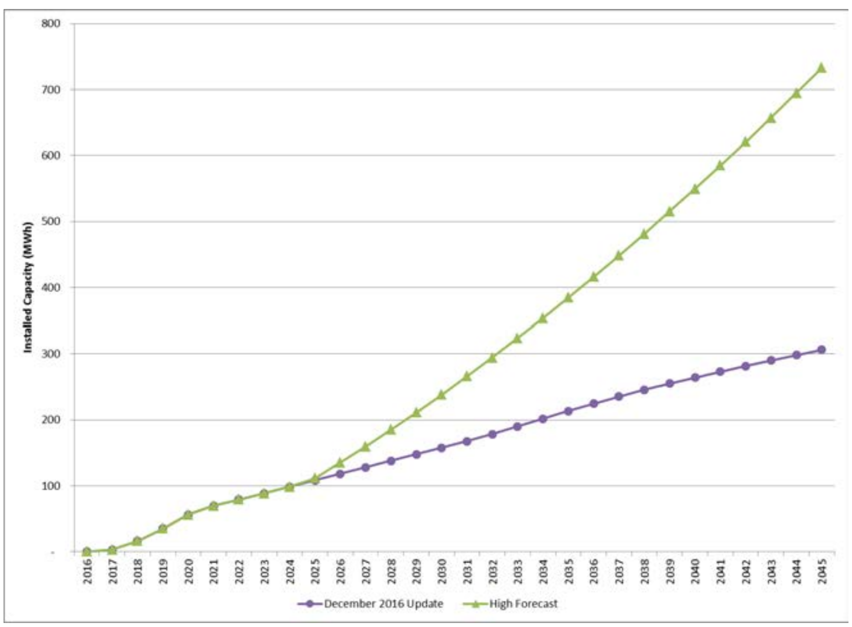


Figure J-15. O'ahu Market Self-Supply DESS Capacity Forecasts

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

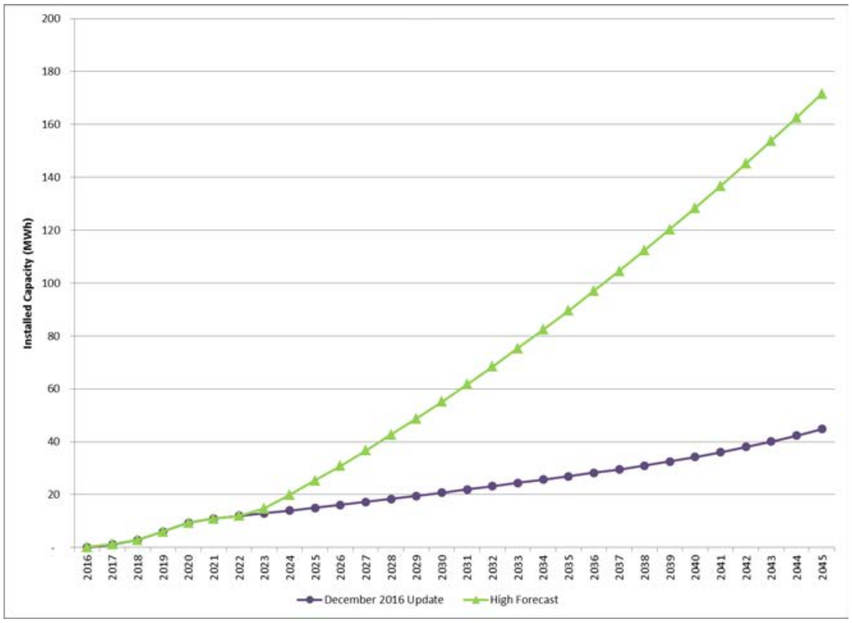


Figure J-16. Maui Market Self-Supply DESS Capacity Forecasts

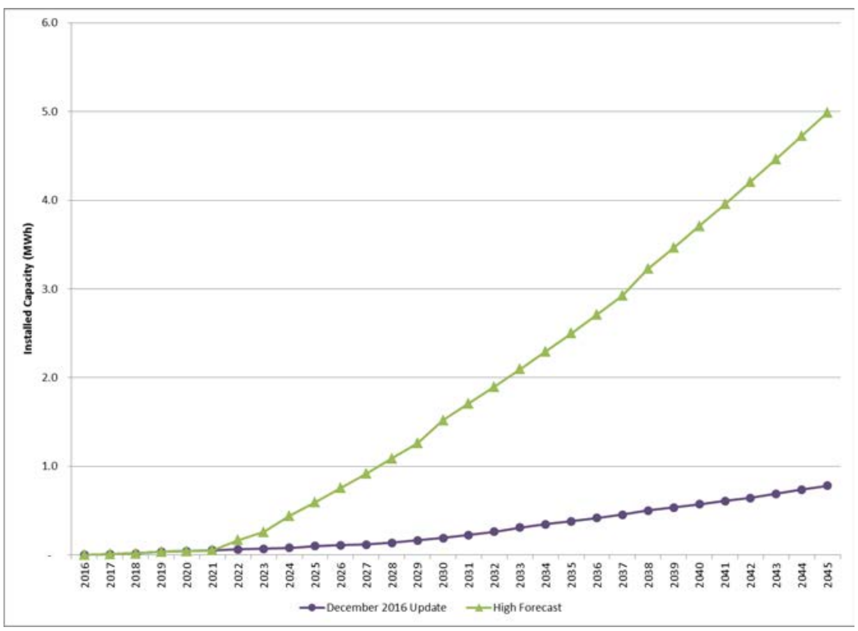


Figure J-17. Lana‘i Market Self-Supply DESS Capacity Forecasts

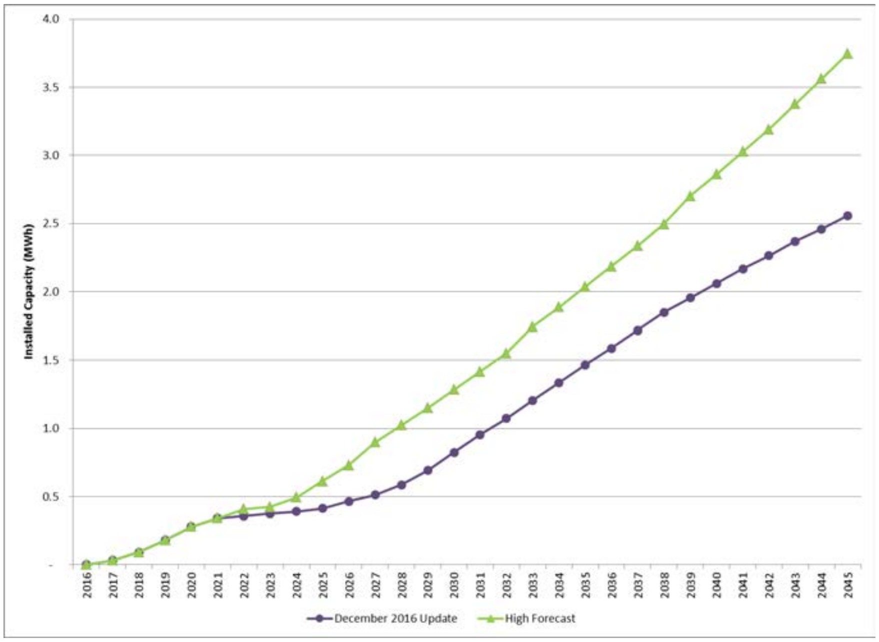


Figure J-18. Moloka'i Market Self-Supply DESS Capacity Forecasts

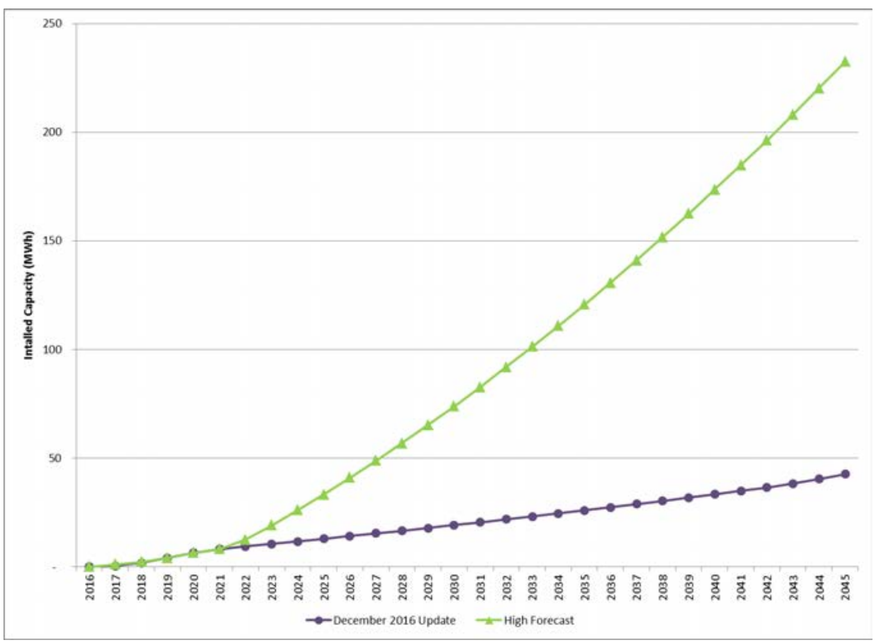


Figure J-19. Hawai'i Island Market Self-Supply DESS Capacity Forecasts

High DG-PV Market Potential

The high DG-PV market potential forecast scenario was also updated to include DESS paired with self-supply PV systems. For the residential customers the Company assumed that 100% of the single-family residential electricity sales would be offset by DG-PV by 2045. The Company assumed that it was unlikely to offset 100% of the commercial customers' load given the amount of rooftop space required and challenges arising from property ownership, and therefore focused on business sectors that currently participate or are likely to participate in a Company program. Roughly, 20-25% of the total commercial sales would be offset by DG-PV in 2045 for all islands with the exception of Lanai (7%) which has fairly low participation to date.

The Company recognized that reaching the high DG-PV market potential by 2045 still required projections that reflect achievable near term potentials before taking off on the path to 2045. There is lead-time involved when standing up new programs, financial incentives and/or the development and deployment of technology solutions. As such, the Company used similar projections of total PV and DESS capacity as the market DG-PV forecast in the near term before ramping up to the high DG-PV market potential. It was also assumed that under the high DG-PV market potential scenario, all residential, small and medium commercial customers would require a DESS for systems installed under the self-supply program since their daytime loads on average may be lower than their evening loads. Therefore in a self-supply program the use of a DESS allows them to self-generate a much larger portion of their energy needs than they would be able to otherwise if their PV system size was limited to not exceed their daytime load. The larger commercial customers on average have larger daytime loads that enable them to benefit significantly from a self-supply program without the need to invest in DESS.

The forecast was not done from a maximum rooftop potential perspective and did not consider whether it was cost effective from a customer or system level perspective. To achieve this higher level of DG-PV and DESS adoption will likely require mandates or significant additional customer incentives.

The Company is continuing efforts to estimate the technical potential for rooftop DG-PV through discussions with companies such as Google and Mapdwell that are developing tools to address this question. More details on the Google and Mapdwell opportunities are described in Appendix H: Renewable Resource Options for O‘ahu.

See Figure J-20 through Figure J-24 for a comparison between four DG-PV forecasts used in the 2016 PSIP updates. Data corresponding to the DG-PV forecast figures are detailed in Table J-22 through Table J-26.

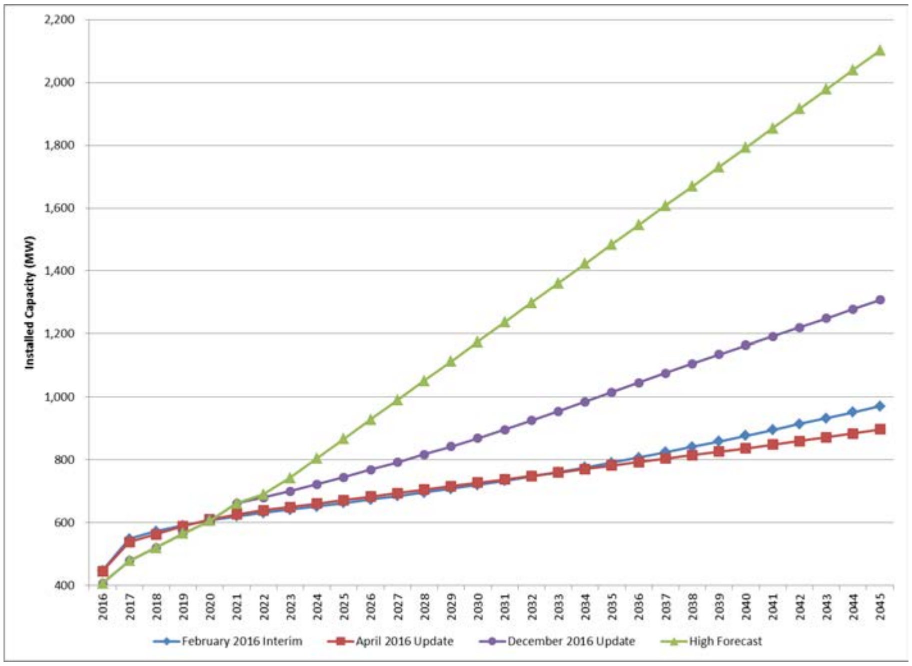


Figure J-20. O‘ahu DG-PV Capacity Forecast Comparison

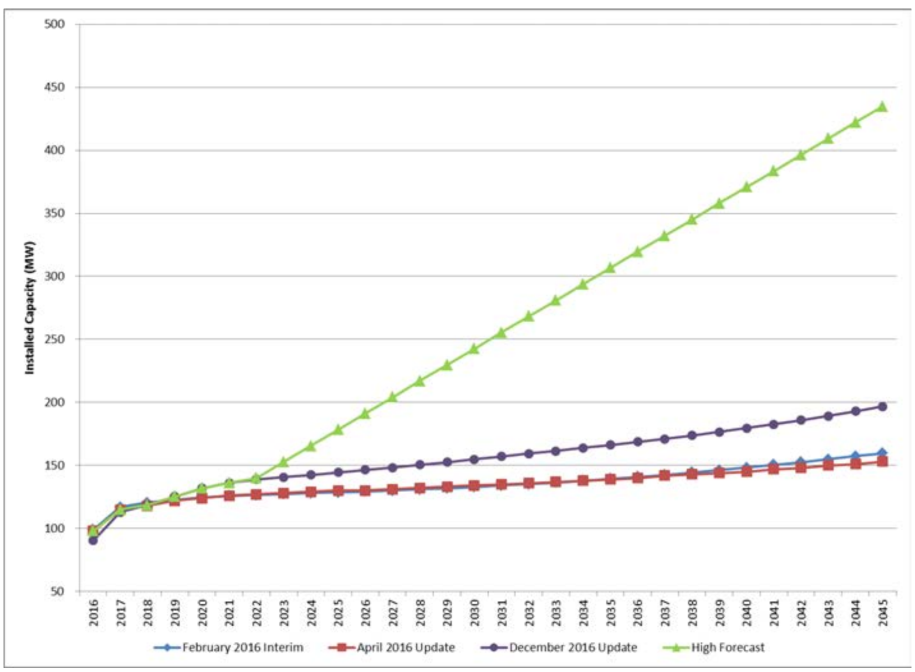


Figure J-21. Maui Island DG-PV Capacity Forecast Comparison

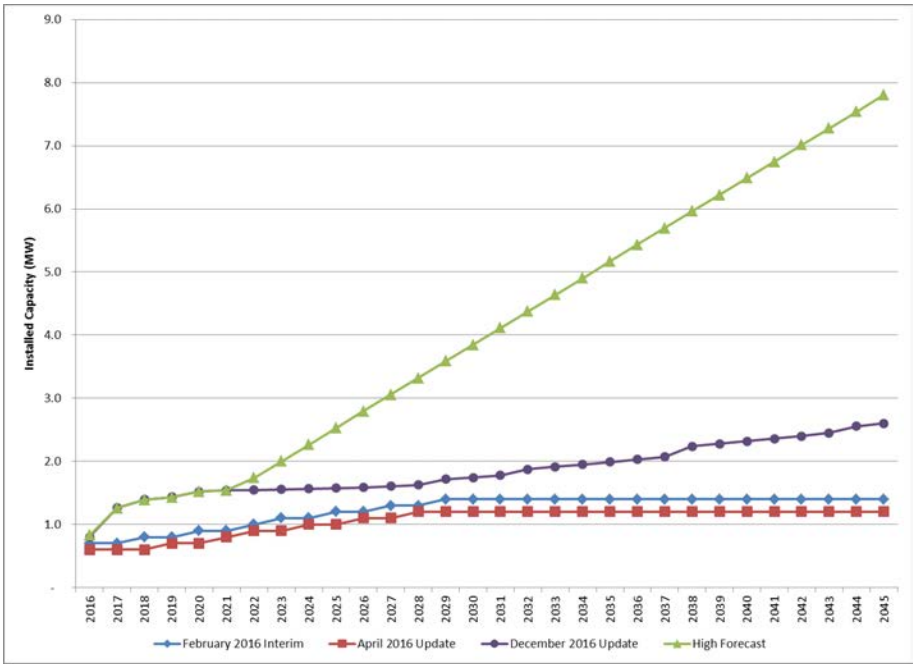


Figure J-22. Lana'i Island DG-PV Capacity Forecast Comparison

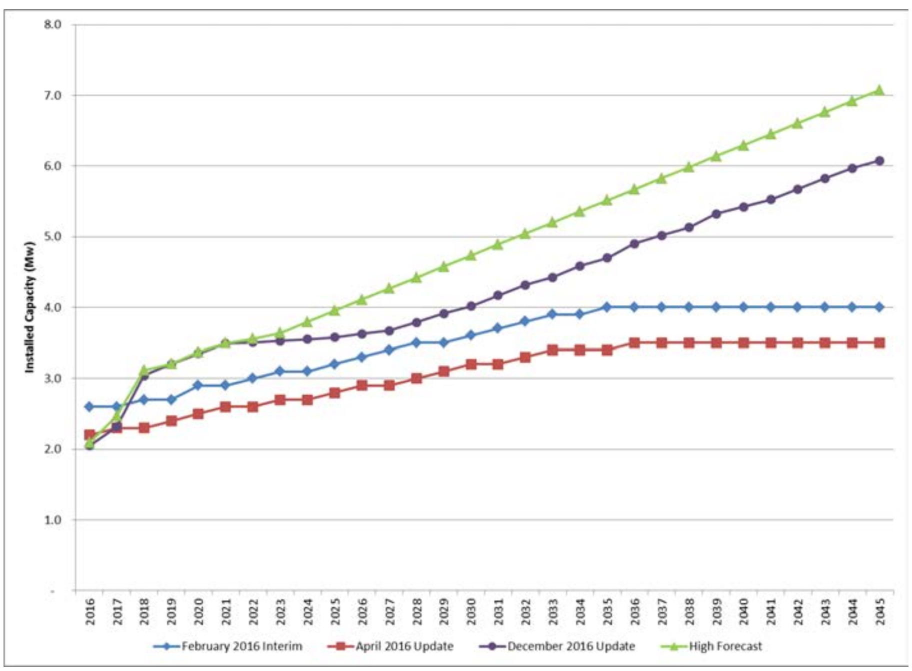


Figure J-23. Moloka'i Island DG-PV Capacity Forecast Comparison

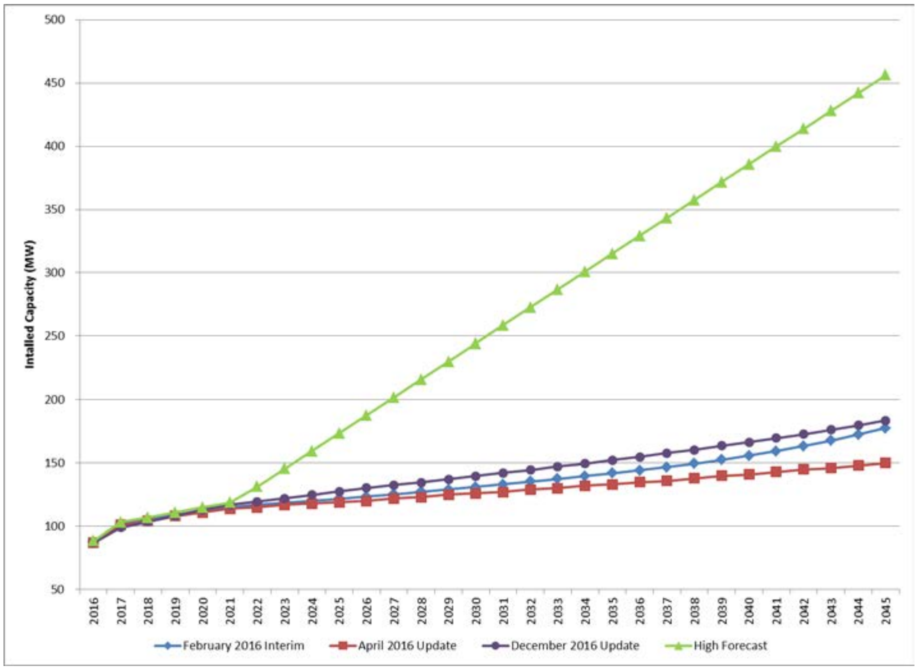


Figure J-24. Hawai‘i Island DG-PV Capacity Forecast Comparison

Electric Vehicles. The development of the electric vehicles forecast was based on estimating the number of electric vehicles purchased per year using a historical average annual growth rate then multiplying by an estimate of the annual energy used per vehicle. The annual energy used per vehicle was based on the average miles driven per year as stated in the Hawai‘i Data Book multiplied by the energy required per mile averaged over a 2015 Nissan Leaf, Chevy Volt, Chevy Spark, and Tesla Model S.

Peak Demand Forecast

The peak demand forecast was derived using Itron’s proprietary modeling software, MetrixLT. The software utilizes load profiles by rate schedule from class load studies conducted by the Company and the underlying sales forecast derived by rate schedule. The rate schedule load profiles adjusted for forecasted sales are aggregated to produce system profiles. The Company employed the highest system demands to calculate the underlying annual system. After determining the underlying peak forecast, the Company made adjustments that were outside of the underlying forecasts, for example impacts from energy efficiency measures. No adjustments were made to the underlying system peak forecast for DG-PV or electric vehicles as forecasted system peaks are expected to occur during the evening.

The underlying peak forecast for Lana‘i and Moloka‘i Divisions were derived by employing a sales load factor method which compares the annual sales in MWh against the peak load in MW multiplied by the number of hours during the year.

The peak demands of each operating company forecasted through the study period expressed at the net generation level are in Figure J-25 through Figure J-29 and do not include the impacts of customers' distributed storage systems or the effects of DR programs on the peaks. Behind the meter DESS impacts to evening peaks are accounted for in the DR peak reduction impacts to allow optimization of the use of the resources and to avoid the possibility of double-counting the impacts. Inclusion of the DESS impacts in the DR analysis allows the DR modeling to potentially increase the value of these DESS resources by incenting DESS energy outflow based on grid system needs, which may differ from the customer's native usage profile. Data for the peak forecast projections are detailed in Table J-12 through Table J-16.

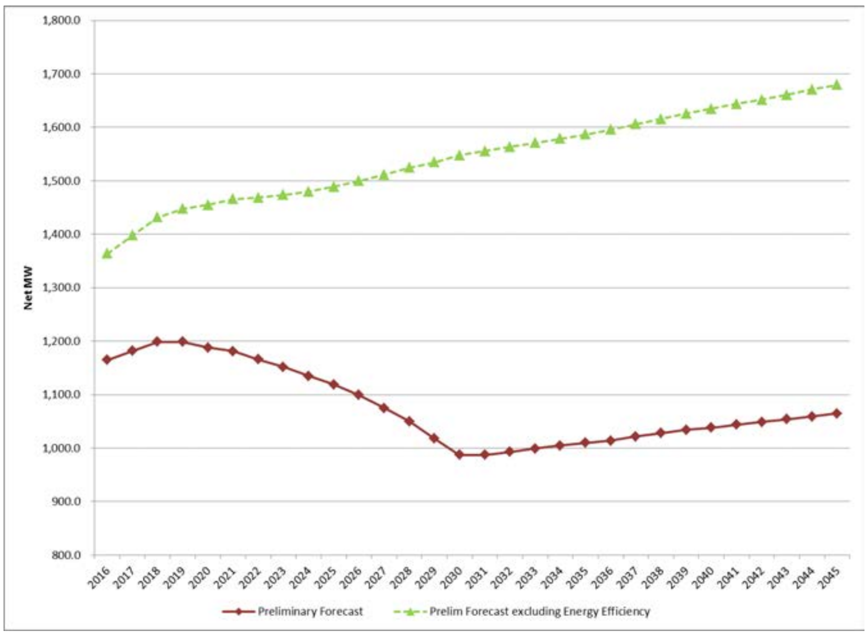


Figure J-25. O'ahu Generation Level Peak Demand

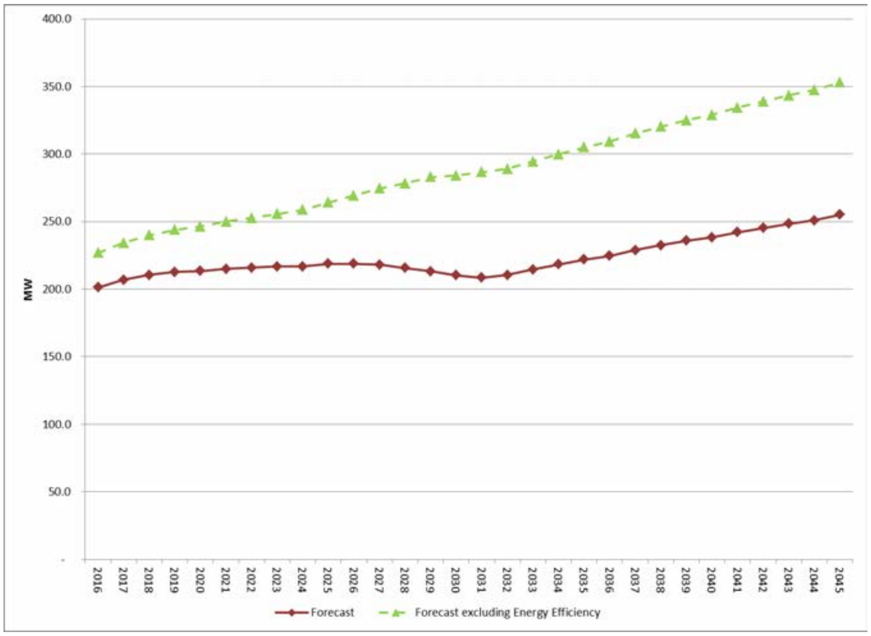


Figure J-26. Maui Island Generation Level Peak Demand

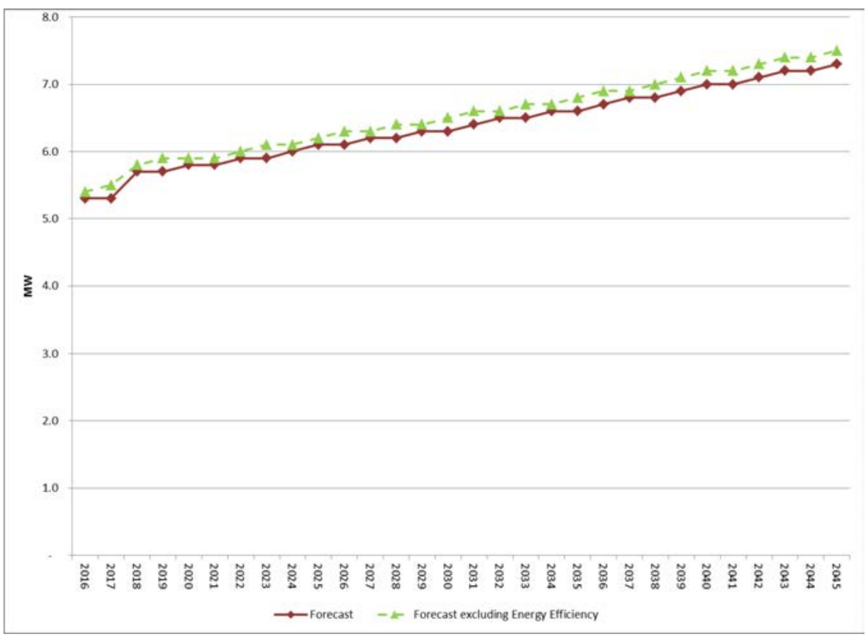


Figure J-27. Lana‘i Generation Level Peak Demand

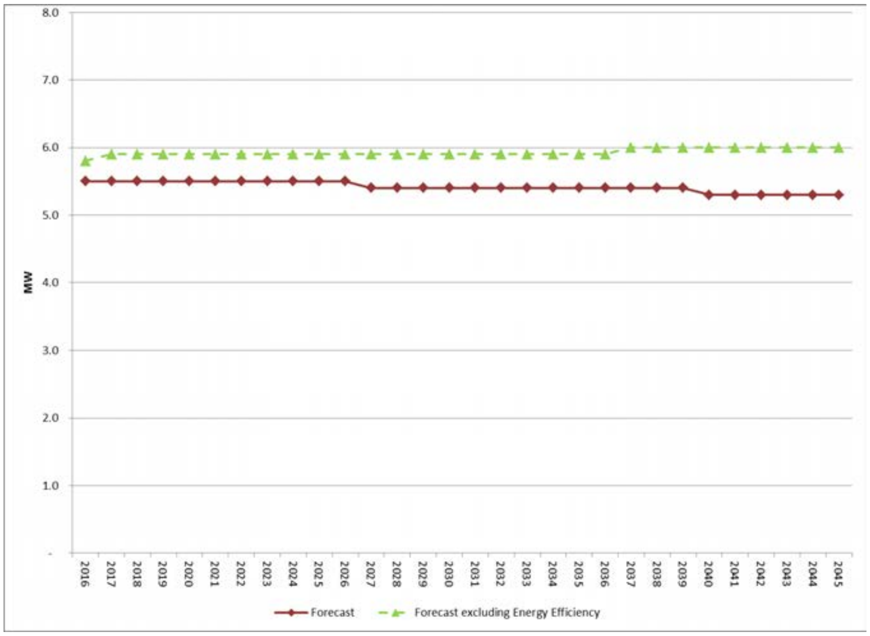


Figure J-28. Moloka'i Generation Level Peak Demand

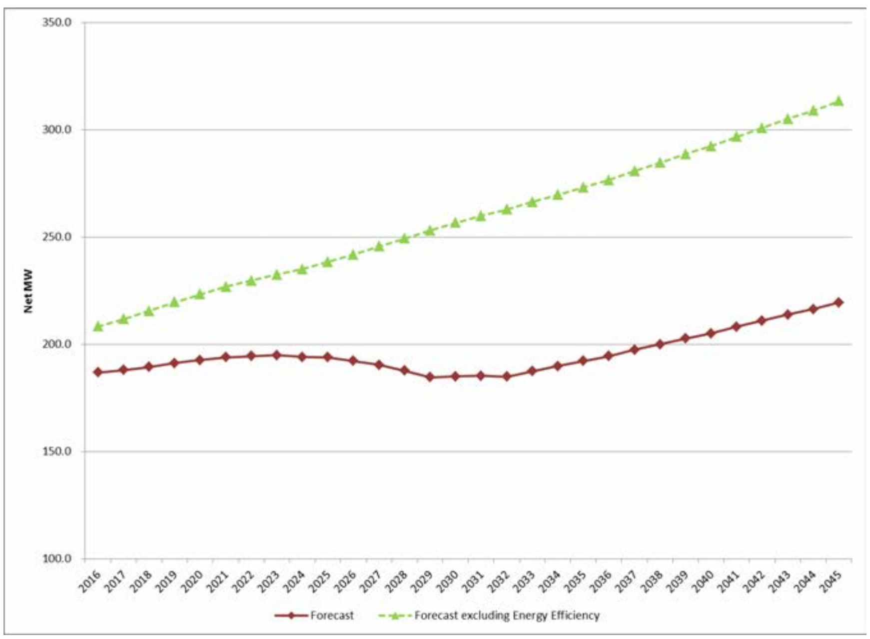


Figure J-29. Hawai'i Island Generation Level Peak Demand

Comparison to the April 2016 PSIP Update Forecast

The forecasts used in this December 2016 update differ from the April 2016 update only in the amount of sales offset by customer-sited DG-PV generation due to the updated DG-PV forecasts (Table J-17 and Table J-21).

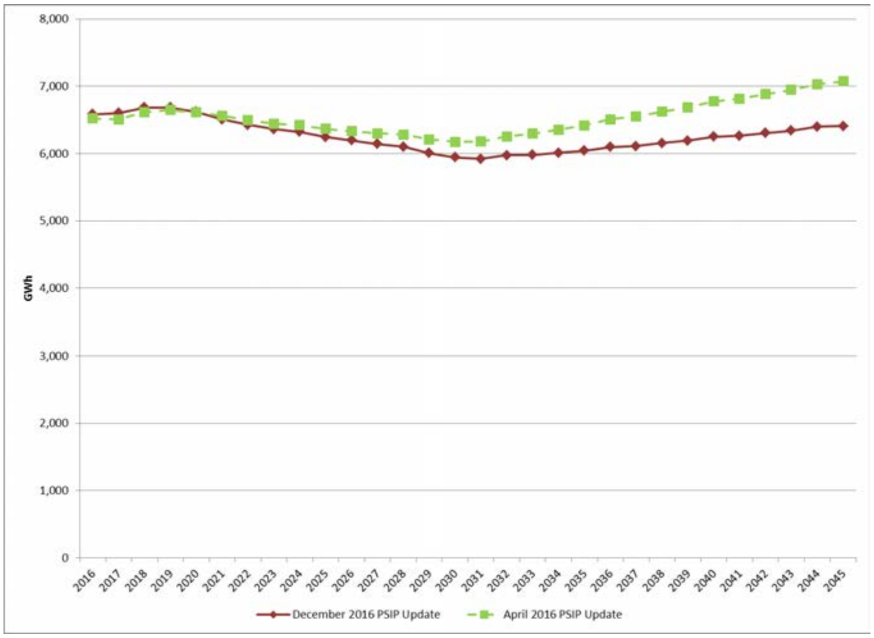


Figure J-30. O'ahu Sales Forecast Comparison

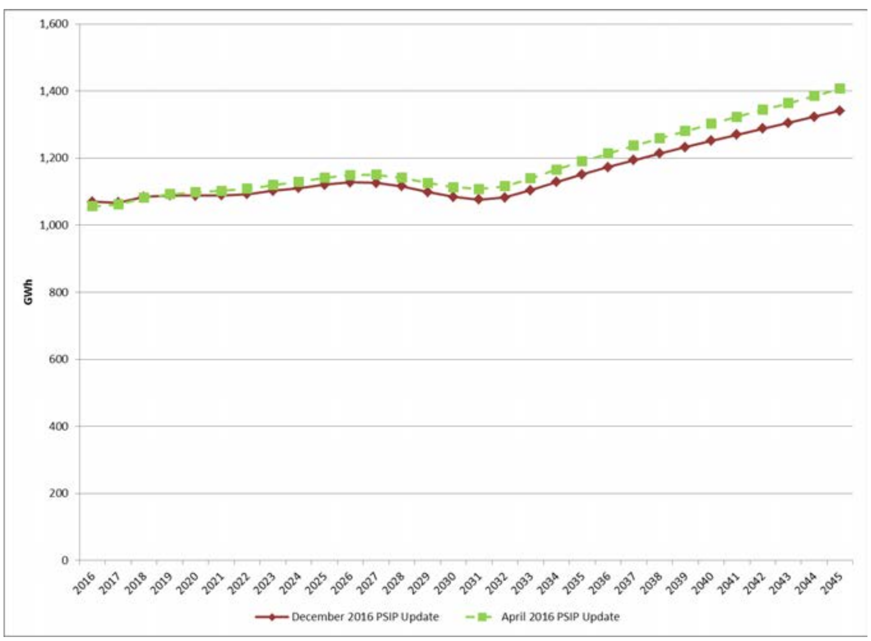


Figure J-31. Maui Island Sales Forecast Comparison

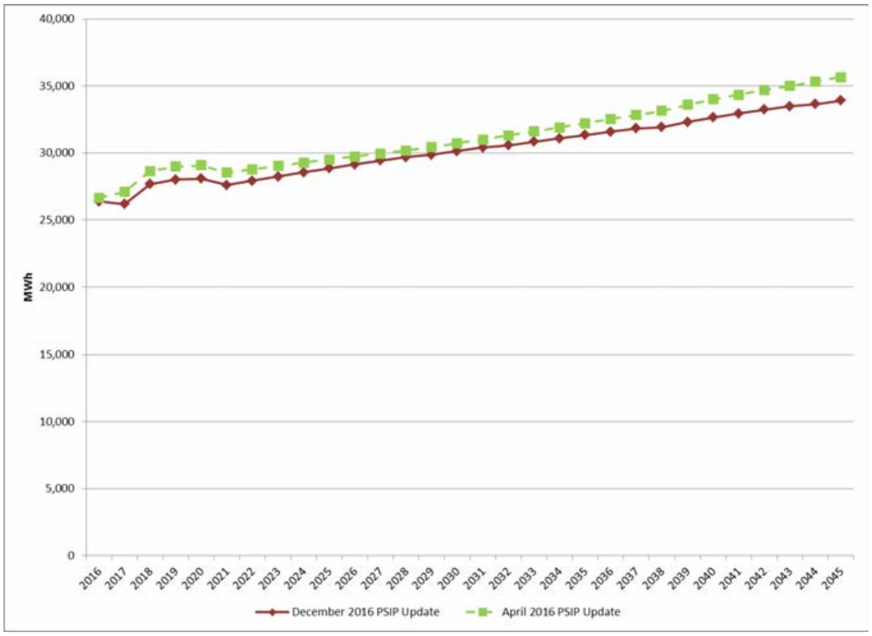


Figure J-32. Lana'i Sales Forecast Comparison

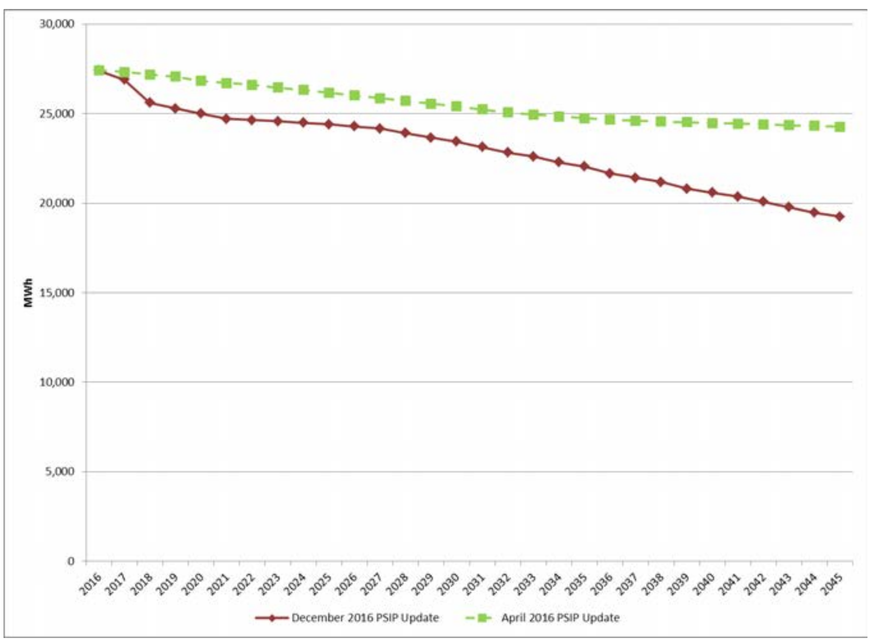


Figure J-33. Moloka'i Sales Forecast Comparison

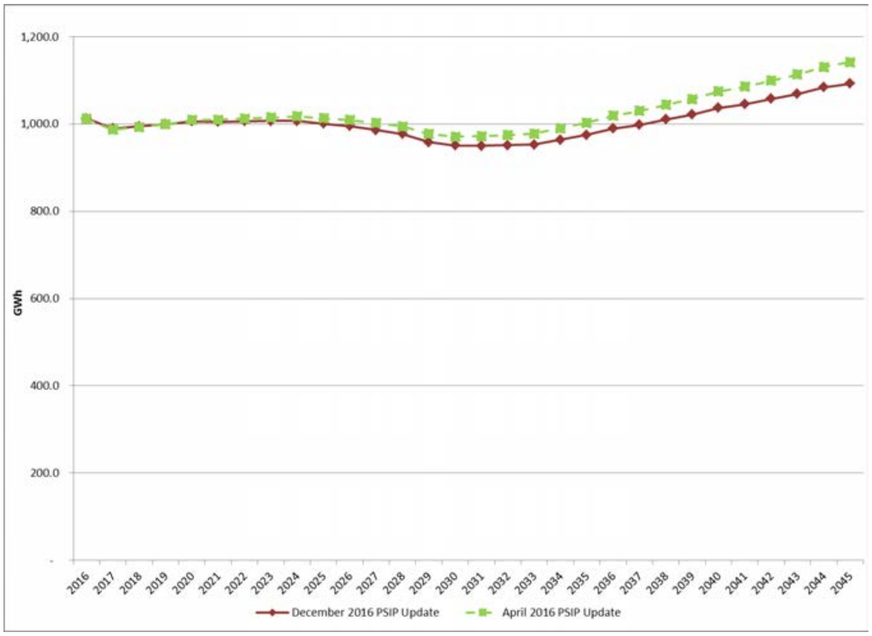


Figure J-34. Hawai'i Island Sales Forecast Comparison

See Table J-17 through Table J-21 for the detailed sales comparison between the sales forecasts used for the December 2016 PSIP update and the April 2016 PSIP update.

Note that the peak forecasts were developed using the method described in the prior page. There is no change to the peak forecasts since the April 2016 PSIP update. Self-supply program DESS energy outflows can reduce the peak loads in the future, however for reasons explained earlier those impacts are reflected in the DR impacts rather than the peak forecast.

UHERO's Economic Forecasts

UHERO's forecasts for non-farm jobs, personal income, and visitor arrivals were used in developing the sales forecasts. Figure J-35 through Figure J-37 compare the economic forecasts developed by UHERO in 2015 against the forecast developed in 2014, illustrating the less optimistic outlook between the two forecasts. See also Table J-32 through Table J-34 for a comparison between UHERO's April 2014 and April 2015 economic forecasts.

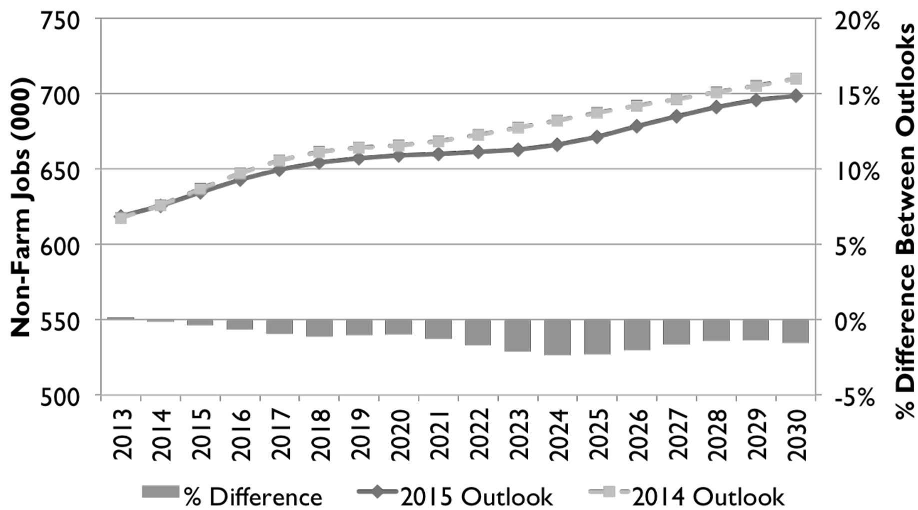


Figure J-35. Hawai'i Non-Farm Job Count Forecast Comparison

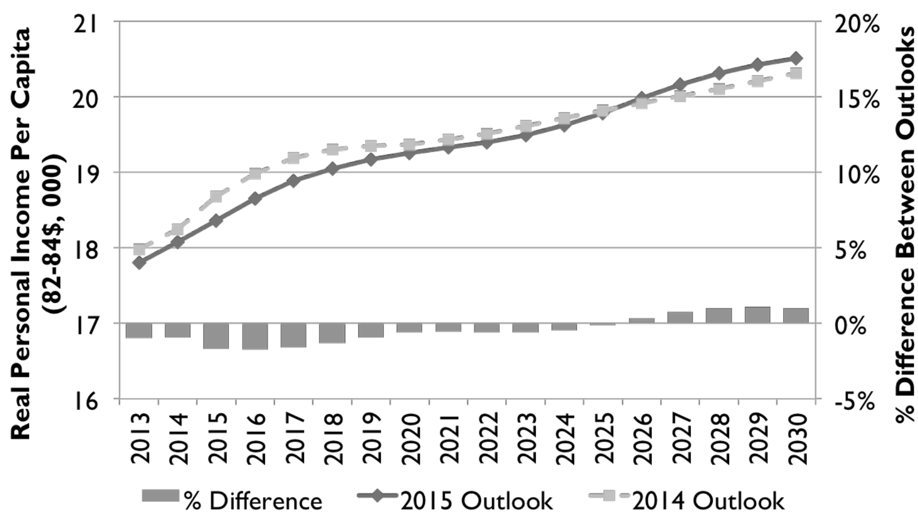


Figure J-36. Hawai'i Real Personal Income per Capita Forecast Comparison

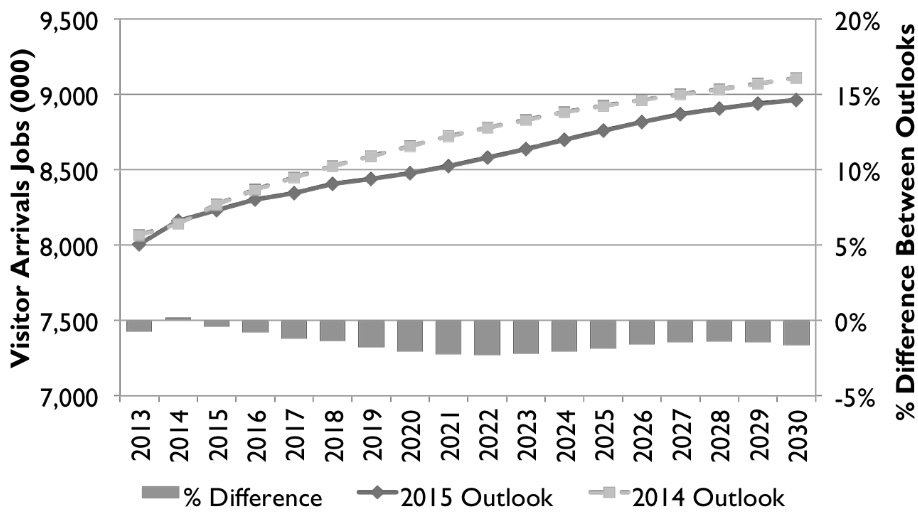


Figure J-37. Hawai'i Visitor Arrival Forecast Comparison

Load Profiles

Available generating resources must be able to meet a demand profile over a period of time that doesn't include customer-sited distributed generation. Our analysis used a demand profile in two ways:

- An annual hourly load profile (8,760 data points: 365 days at 24 hours a day).
- A sub-hourly load profile data, which model intra-hour issues associated with ramping of generating resources and energy storage in response to variable renewable generation.

Because of the proliferation of customer-sited distributed generation, the net load profile has changed dramatically over the past few years. Our analysis assumed a system gross load profile. The model includes the profile of customer-sited distributed generation, which results in the net load to be served.

Sub-Hourly Profile

Black & Veatch has developed sub-hourly profiles for variable generation that includes rooftop solar panels, and utility-scale solar and wind. These profiles form the backbone for evaluating the impacts of variable generation and the fleet's ability to meet demand.

Black & Veatch's model is based on historical changes in minute-to-minute generation by asset type and island. Using historical data, the model creates a probability distribution function based on time of day and current generation levels. The probability, then, is a distribution of all the possible changes in demand for an asset type. Combining this probability with random number generation results in the change in output for the next time step for that asset.

The model "fills in" the sub-hourly generation of each asset in between the hourly generation profiles provided by the Hawaiian Electric planning group. Black & Veatch's model ensures that energy production over each day with the sub-hourly profiles matches the production from the hourly model. This daily energy matching aligns total production with models that employ only hourly data.

The difference between the modeling data for sub-hourly versus hourly is dramatic. Figure J-38 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

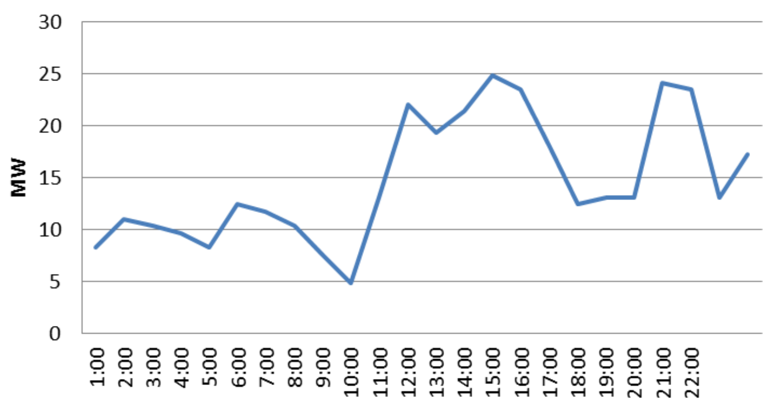


Figure J-38. Wind Unit Day Hourly Profile Example

Figure J-39 depicts an example day of an hourly profile on the Hawaiian Electric grid and the output profile from the Black & Veatch model.

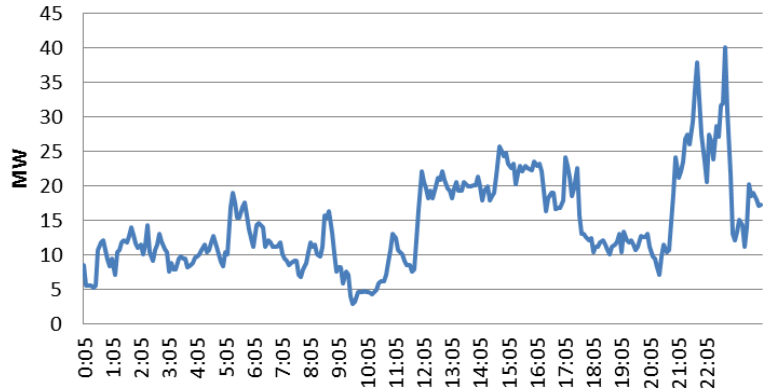


Figure J-39. Wind Unit Day Sub-Hourly Profile Example

SALES FORECASTS

O'ahu Customer Level Sales Forecast

GWh	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	8,286	(1,077)	(656)	31	6,585
2017	8,481	(1,149)	(772)	42	6,602
2018	8,691	(1,224)	(839)	55	6,684
2019	8,817	(1,288)	(912)	69	6,686
2020	8,886	(1,375)	(977)	86	6,620
2021	8,933	(1,466)	(1,067)	106	6,507
2022	8,953	(1,557)	(1,097)	129	6,428
2023	8,987	(1,647)	(1,129)	153	6,363
2024	9,054	(1,744)	(1,164)	179	6,325
2025	9,087	(1,846)	(1,201)	207	6,247
2026	9,154	(1,957)	(1,239)	236	6,194
2027	9,230	(2,080)	(1,277)	267	6,140
2028	9,329	(2,209)	(1,317)	300	6,103
2029	9,377	(2,346)	(1,358)	334	6,007
2030	9,460	(2,486)	(1,400)	370	5,944
2031	9,513	(2,553)	(1,445)	407	5,923
2032	9,581	(2,561)	(1,491)	444	5,973
2033	9,605	(2,568)	(1,539)	482	5,981
2034	9,652	(2,574)	(1,588)	521	6,011
2035	9,704	(2,584)	(1,637)	560	6,042
2036	9,785	(2,601)	(1,686)	599	6,097
2037	9,823	(2,615)	(1,735)	639	6,112
2038	9,886	(2,628)	(1,783)	679	6,154
2039	9,947	(2,644)	(1,830)	719	6,192
2040	10,032	(2,665)	(1,875)	759	6,250
2041	10,066	(2,680)	(1,921)	799	6,264
2042	10,122	(2,692)	(1,966)	841	6,305
2043	10,178	(2,707)	(2,013)	883	6,342
2044	10,257	(2,726)	(2,060)	927	6,397
2045	10,288	(2,741)	(2,108)	971	6,409

Table J-7. O'ahu Customer Level Sales Forecast

Maui Island Customer Level Sales Forecast

GWh	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	1,351	(142)	(141)	2	1,070
2017	1,392	(152)	(176)	3	1,067
2018	1,426	(163)	(185)	5	1,084
2019	1,450	(173)	(195)	7	1,089
2020	1,468	(183)	(206)	9	1,088
2021	1,483	(194)	(212)	12	1,089
2022	1,499	(204)	(217)	14	1,093
2023	1,518	(214)	(219)	17	1,102
2024	1,541	(229)	(222)	21	1,110
2025	1,568	(247)	(225)	24	1,121
2026	1,599	(270)	(228)	28	1,127
2027	1,626	(301)	(231)	32	1,126
2028	1,649	(334)	(235)	35	1,116
2029	1,668	(371)	(238)	39	1,099
2030	1,684	(401)	(242)	43	1,084
2031	1,698	(424)	(245)	47	1,076
2032	1,717	(437)	(249)	51	1,082
2033	1,743	(442)	(252)	55	1,104
2034	1,775	(450)	(256)	59	1,128
2035	1,805	(458)	(259)	63	1,151
2036	1,835	(467)	(263)	67	1,173
2037	1,865	(476)	(267)	72	1,194
2038	1,893	(484)	(271)	76	1,214
2039	1,920	(492)	(275)	80	1,233
2040	1,948	(500)	(280)	85	1,252
2041	1,974	(508)	(285)	89	1,270
2042	2,000	(516)	(290)	94	1,288
2043	2,026	(524)	(295)	98	1,305
2044	2,053	(532)	(301)	103	1,323
2045	2,080	(540)	(307)	108	1,341

Table J-8. Maui Island Customer Level Sales Forecast

Lana'i Customer Level Sales Forecast

MWh	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	28,114	(585)	(1,150)	–	26,379
2017	28,596	(602)	(1,805)	–	26,189
2018	30,273	(618)	(1,988)	–	27,666
2019	30,701	(635)	(2,045)	–	28,021
2020	30,910	(652)	(2,171)	–	28,087
2021	30,472	(668)	(2,200)	–	27,604
2022	30,811	(685)	(2,211)	–	27,915
2023	31,158	(702)	(2,222)	–	28,234
2024	31,510	(719)	(2,234)	–	28,558
2025	31,846	(735)	(2,251)	–	28,860
2026	32,169	(752)	(2,268)	–	29,149
2027	32,493	(769)	(2,297)	–	29,428
2028	32,801	(785)	(2,325)	–	29,691
2029	33,122	(802)	(2,451)	–	29,869
2030	33,449	(819)	(2,491)	–	30,140
2031	33,771	(835)	(2,537)	–	30,398
2032	34,102	(852)	(2,674)	–	30,577
2033	34,438	(869)	(2,731)	–	30,838
2034	34,753	(885)	(2,782)	–	31,085
2035	35,076	(902)	(2,839)	–	31,335
2036	35,409	(919)	(2,902)	–	31,589
2037	35,731	(935)	(2,959)	–	31,837
2038	36,062	(952)	(3,193)	–	31,917
2039	36,539	(969)	(3,256)	–	32,314
2040	36,949	(985)	(3,313)	–	32,651
2041	37,319	(1,002)	(3,370)	–	32,947
2042	37,676	(1,019)	(3,428)	–	33,229
2043	38,008	(1,035)	(3,496)	–	33,476
2044	38,348	(1,052)	(3,650)	–	33,646
2045	38,690	(1,069)	(3,719)	–	33,902

Table J-9. Lana'i Customer Level Sales Forecast

Moloka‘i Customer Level Sales Forecast

MWh	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	32,779	(1,829)	(3,550)	–	27,400
2017	32,810	(1,896)	(4,015)	–	26,899
2018	32,837	(1,963)	(5,270)	–	25,604
2019	32,864	(2,030)	(5,545)	–	25,289
2020	32,891	(2,097)	(5,808)	–	24,986
2021	32,918	(2,164)	(6,042)	–	24,712
2022	32,945	(2,231)	(6,068)	–	24,646
2023	32,972	(2,298)	(6,106)	–	24,568
2024	32,999	(2,365)	(6,148)	–	24,486
2025	33,027	(2,433)	(6,195)	–	24,399
2026	33,052	(2,500)	(6,276)	–	24,277
2027	33,078	(2,567)	(6,354)	–	24,158
2028	33,104	(2,634)	(6,557)	–	23,913
2029	33,130	(2,701)	(6,777)	–	23,652
2030	33,156	(2,768)	(6,957)	–	23,431
2031	33,182	(2,835)	(7,224)	–	23,123
2032	33,208	(2,902)	(7,480)	–	22,826
2033	33,235	(2,969)	(7,666)	–	22,599
2034	33,261	(3,036)	(7,943)	–	22,282
2035	33,287	(3,103)	(8,139)	–	22,045
2036	33,313	(3,170)	(8,492)	–	21,651
2037	33,340	(3,237)	(8,688)	–	21,414
2038	33,366	(3,305)	(8,884)	–	21,178
2039	33,393	(3,372)	(9,222)	–	20,799
2040	33,419	(3,439)	(9,391)	–	20,589
2041	33,446	(3,506)	(9,572)	–	20,368
2042	33,472	(3,573)	(9,831)	–	20,068
2043	33,499	(3,640)	(10,090)	–	19,769
2044	33,525	(3,707)	(10,344)	–	19,474
2045	33,552	(3,774)	(10,524)	–	19,254

Table J-10. Moloka‘i Customer Level Sales Forecast

Hawai'i Island Customer Level Sales Forecast

GWh	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Customer Level Sales Forecast
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	1,257	(116)	(129)	0.5	1,012
2017	1,264	(128)	(147)	0.7	989
2018	1,287	(140)	(153)	0.8	994
2019	1,310	(151)	(161)	1.0	999
2020	1,335	(163)	(167)	1.1	1,006
2021	1,351	(174)	(173)	1.2	1,005
2022	1,368	(186)	(177)	1.3	1,007
2023	1,384	(198)	(181)	1.4	1,007
2024	1,403	(212)	(185)	1.6	1,007
2025	1,418	(230)	(189)	1.7	1,001
2026	1,438	(252)	(193)	1.9	995
2027	1,460	(279)	(196)	2.0	986
2028	1,484	(310)	(199)	2.2	977
2029	1,503	(343)	(203)	2.3	959
2030	1,523	(368)	(207)	2.5	951
2031	1,542	(383)	(211)	2.6	950
2032	1,562	(400)	(214)	2.8	951
2033	1,578	(410)	(218)	2.9	953
2034	1,597	(414)	(222)	3.1	964
2035	1,616	(419)	(226)	3.2	975
2036	1,640	(425)	(229)	3.4	989
2037	1,659	(431)	(234)	3.6	998
2038	1,681	(437)	(238)	3.7	1,010
2039	1,704	(444)	(242)	3.9	1,022
2040	1,730	(450)	(247)	4.1	1,037
2041	1,750	(457)	(251)	4.3	1,045
2042	1,773	(464)	(256)	4.4	1,058
2043	1,796	(471)	(261)	4.6	1,069
2044	1,823	(478)	(266)	4.8	1,084
2045	1,844	(485)	(272)	5.0	1,092

Table J-11. Hawai'i Island Customer Level Sales Forecast

PEAK DEMAND FORECASTS

O'ahu Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Net Peak Forecast*
Year	*a*	*b*	*c*	*d*	e = *a* + *b* + *c* + *d*
2016	1,363.7	(198.7)	0	0	1,165.0
2017	1,397.7	(215.7)	0	0	1,182.0
2018	1,431.7	(232.7)	0	0	1,199.0
2019	1,447.7	(248.7)	0	0	1,199.0
2020	1,454.7	(266.7)	0	0	1,188.0
2021	1,465.7	(284.7)	0	0	1,181.0
2022	1,468.7	(302.7)	0	0	1,166.0
2023	1,473.7	(321.7)	0	0	1,152.0
2024	1,479.7	(344.7)	0	0	1,135.0
2025	1,488.7	(369.7)	0	0	1,119.0
2026	1,499.7	(400.7)	0	0	1,099.0
2027	1,511.7	(436.7)	0	0	1,075.0
2028	1,524.7	(474.7)	0	0	1,050.0
2029	1,534.7	(516.7)	0	0	1,018.0
2030	1,547.7	(560.7)	0	0	987.0
2031	1,555.7	(568.7)	0	0	987.0
2032	1,563.7	(570.7)	0	0	993.0
2033	1,570.7	(571.7)	0	0	999.0
2034	1,578.7	(573.7)	0	0	1,005.0
2035	1,586.7	(576.7)	0	0	1,010.0
2036	1,595.7	(581.7)	0	0	1,014.0
2037	1,605.7	(583.7)	0	0	1,022.0
2038	1,615.7	(587.7)	0	0	1,028.0
2039	1,625.7	(591.7)	0	0	1,034.0
2040	1,634.7	(596.7)	0	0	1,038.0
2041	1,643.7	(599.7)	0	0	1,044.0
2042	1,651.7	(602.7)	0	0	1,049.0
2043	1,660.7	(606.7)	0	0	1,054.0
2044	1,670.7	(611.7)	0	0	1,059.0
2045	1,679.7	(614.7)	0	0	1,065.0

* System peak occurs in the evening.

Table J-12. O'ahu Generation Level Peak Demand Forecast (MW)

Maui Island Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Net Peak Forecast*
Year	a	b	c	d	e = a + b + c + d
2016	226.7	(25.6)	0	0.2	201.3
2017	234.0	(27.5)	0	0.3	206.8
2018	239.4	(29.3)	0	0.4	210.5
2019	243.4	(31.3)	0	0.6	212.7
2020	245.7	(33.2)	0	0.8	213.3
2021	248.9	(35.0)	0	1.0	214.9
2022	251.5	(37.0)	0	1.3	215.8
2023	254.7	(38.8)	0	0.8	216.7
2024	257.8	(42.1)	0	0.9	216.7
2025	263.0	(45.4)	0	1.1	218.7
2026	268.1	(50.6)	0	1.2	218.7
2027	273.0	(56.2)	0	1.4	218.2
2028	276.7	(62.6)	0	1.6	215.6
2029	281.2	(69.8)	0	1.7	213.2
2030	282.2	(73.9)	0	1.9	210.2
2031	284.5	(78.1)	0	2.1	208.6
2032	286.9	(78.8)	0	2.3	210.4
2033	291.9	(79.9)	0	2.5	214.5
2034	297.1	(81.5)	0	2.6	218.2
2035	302.1	(83.1)	0	2.8	221.9
2036	306.3	(84.6)	0	3.0	224.7
2037	312.1	(86.3)	0	3.2	229.0
2038	316.8	(87.8)	0	3.4	232.5
2039	321.4	(89.2)	0	3.6	235.8
2040	325.2	(90.7)	0	3.8	238.3
2041	330.3	(92.2)	0	4.0	242.2
2042	334.7	(93.5)	0	4.2	245.3
2043	339.0	(95.0)	0	4.4	248.4
2044	342.8	(96.5)	0	4.6	250.9
2045	348.2	(97.9)	0	4.8	255.1

* System peak occurs in the evening.

Table J-13. Maui Island Generation Level Peak Demand Forecast (MW)

Lana'i Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Net Peak Forecast*
Year	*a*	*b*	*c*	*d*	e = *a* + *b* + *c* + *d*
2016	5.4	(0.1)	0	0	5.3
2017	5.5	(0.2)	0	0	5.3
2018	5.8	(0.1)	0	0	5.7
2019	5.9	(0.2)	0	0	5.7
2020	5.9	(0.1)	0	0	5.8
2021	5.9	(0.1)	0	0	5.8
2022	6.0	(0.1)	0	0	5.9
2023	6.1	(0.2)	0	0	5.9
2024	6.1	(0.1)	0	0	6.0
2025	6.2	(0.1)	0	0	6.1
2026	6.3	(0.2)	0	0	6.1
2027	6.3	(0.1)	0	0	6.2
2028	6.4	(0.2)	0	0	6.2
2029	6.4	(0.1)	0	0	6.3
2030	6.5	(0.2)	0	0	6.3
2031	6.6	(0.2)	0	0	6.4
2032	6.6	(0.1)	0	0	6.5
2033	6.7	(0.2)	0	0	6.5
2034	6.7	(0.1)	0	0	6.6
2035	6.8	(0.2)	0	0	6.6
2036	6.9	(0.2)	0	0	6.7
2037	6.9	(0.1)	0	0	6.8
2038	7.0	(0.2)	0	0	6.8
2039	7.1	(0.2)	0	0	6.9
2040	7.2	(0.2)	0	0	7.0
2041	7.2	(0.2)	0	0	7.0
2042	7.3	(0.2)	0	0	7.1
2043	7.4	(0.2)	0	0	7.2
2044	7.4	(0.2)	0	0	7.2
2045	7.5	(0.2)	0	0	7.3

* System peak occurs in the evening.

Table J-14. Lana'i Generation Level Peak Demand Forecast (MW)

Moloka'i Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Net Peak Forecast*
Year	*a*	*b*	*c*	*d*	e = *a* + *b* + *c* + *d*
2016	5.8	(0.3)	0	0	5.5
2017	5.9	(0.4)	0	0	5.5
2018	5.9	(0.4)	0	0	5.5
2019	5.9	(0.4)	0	0	5.5
2020	5.9	(0.4)	0	0	5.5
2021	5.9	(0.4)	0	0	5.5
2022	5.9	(0.4)	0	0	5.5
2023	5.9	(0.4)	0	0	5.5
2024	5.9	(0.4)	0	0	5.5
2025	5.9	(0.4)	0	0	5.5
2026	5.9	(0.4)	0	0	5.5
2027	5.9	(0.5)	0	0	5.4
2028	5.9	(0.5)	0	0	5.4
2029	5.9	(0.5)	0	0	5.4
2030	5.9	(0.5)	0	0	5.4
2031	5.9	(0.5)	0	0	5.4
2032	5.9	(0.5)	0	0	5.4
2033	5.9	(0.5)	0	0	5.4
2034	5.9	(0.5)	0	0	5.4
2035	5.9	(0.5)	0	0	5.4
2036	5.9	(0.5)	0	0	5.4
2037	6.0	(0.6)	0	0	5.4
2038	6.0	(0.6)	0	0	5.4
2039	6.0	(0.6)	0	0	5.4
2040	6.0	(0.7)	0	0	5.3
2041	6.0	(0.7)	0	0	5.3
2042	6.0	(0.7)	0	0	5.3
2043	6.0	(0.7)	0	0	5.3
2044	6.0	(0.7)	0	0	5.3
2045	6.0	(0.7)	0	0	5.3

* System peak occurs in the evening.

Table J-15. Moloka'i Generation Level Peak Demand Forecast (MW)

Hawai'i Island Generation Level Peak Demand Forecast

MW	Underlying Forecast	Energy Efficiency	DG-PV	Electric Vehicles	Net Peak Forecast*
Year	a	b	c	d	e = a + b + c + d
2016	208.2	(21.4)	0	0	186.8
2017	211.6	(23.7)	0	0	187.9
2018	215.4	(26.0)	0	0	189.4
2019	219.5	(28.3)	0	0	191.2
2020	223.2	(30.6)	0	0	192.6
2021	226.7	(32.9)	0	0	193.8
2022	229.6	(35.2)	0	0	194.4
2023	232.4	(37.5)	0	0	194.9
2024	235.0	(41.0)	0	0	194.0
2025	238.3	(44.5)	0	0	193.8
2026	241.8	(49.6)	0	0	192.2
2027	245.6	(55.3)	0	0	190.3
2028	249.2	(61.6)	0	0	187.6
2029	253.1	(68.6)	0	0	184.5
2030	256.6	(71.6)	0	0	185.0
2031	259.9	(74.7)	0	0	185.2
2032	262.8	(78.0)	0	0	184.8
2033	266.3	(78.9)	0	0	187.4
2034	269.6	(79.8)	0	0	189.8
2035	273.1	(80.9)	0	0	192.2
2036	276.5	(82.1)	0	0	194.4
2037	280.7	(83.3)	0	0	197.4
2038	284.6	(84.6)	0	0	200.0
2039	288.6	(85.9)	0	0	202.7
2040	292.3	(87.2)	0	0	205.1
2041	296.7	(88.5)	0	0	208.2
2042	300.8	(89.8)	0	0	211.0
2043	305.0	(91.2)	0	0	213.8
2044	308.9	(92.6)	0	0	216.3
2045	313.4	(94.0)	0	0	219.4

* System peak occurs in the evening.

Table J-16. Hawai'i Island Generation Level Peak Demand Forecast (MW)

SALES FORECAST COMPARISONS

O'ahu December 2016 PSIP Update vs April 2016 PSIP Update Sales Forecast Comparisons

GWh	Underlying Forecast Differential	Energy Efficiency Differential	DG-PV Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	0.0	0.0	61.7	0.0	61.7
2017	0.0	0.0	95.6	0.0	95.6
2018	0.0	0.0	69.1	0.0	69.1
2019	0.0	0.0	37.8	0.0	37.8
2020	0.0	0.0	5.9	0.0	5.9
2021	0.0	0.0	(57.3)	0.0	(57.3)
2022	0.0	0.0	(66.8)	0.0	(66.8)
2023	0.0	0.0	(81.9)	0.0	(81.9)
2024	0.0	0.0	(99.1)	0.0	(99.1)
2025	0.0	0.0	(118.2)	0.0	(118.2)
2026	0.0	0.0	(138.4)	0.0	(138.4)
2027	0.0	0.0	(159.2)	0.0	(159.2)
2028	0.0	0.0	(180.8)	0.0	(180.8)
2029	0.0	0.0	(203.8)	0.0	(203.8)
2030	0.0	0.0	(228.6)	0.0	(228.6)
2031	0.0	0.0	(255.3)	0.0	(255.3)
2032	0.0	0.0	(283.8)	0.0	(283.8)
2033	0.0	0.0	(313.9)	0.0	(313.9)
2034	0.0	0.0	(345.3)	0.0	(345.3)
2035	0.0	0.0	(376.7)	0.0	(376.7)
2036	0.0	0.0	(408.4)	0.0	(408.4)
2037	0.0	0.0	(439.3)	0.0	(439.3)
2038	0.0	0.0	(469.1)	0.0	(469.1)
2039	0.0	0.0	(498.3)	0.0	(498.3)
2040	0.0	0.0	(525.6)	0.0	(525.6)
2041	0.0	0.0	(552.7)	0.0	(552.7)
2042	0.0	0.0	(579.5)	0.0	(579.5)
2043	0.0	0.0	(606.6)	0.0	(606.6)
2044	0.0	0.0	(634.2)	0.0	(634.2)
2045	0.0	0.0	(662.5)	0.0	(662.5)

Table J-17. O'ahu December 2016 PSIP Update versus April 2016 PSIP Update Sales Forecast Comparisons (GWh)

Maui Island December 2016 PSIP Update vs April 2016 PSIP Update Sales Forecast Comparisons

GWh	Underlying Forecast Differential	Energy Efficiency Differential	DG-PV Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	–	–	14.0	–	14.0
2017	–	–	5.6	–	5.6
2018	–	–	2.3	–	2.3
2019	–	–	(3.3)	–	(3.3)
2020	–	–	(9.8)	–	(9.8)
2021	–	–	(13.6)	–	(13.6)
2022	–	–	(16.0)	–	(16.0)
2023	–	–	(17.3)	–	(17.3)
2024	–	–	(19.0)	–	(19.0)
2025	–	–	(20.5)	–	(20.5)
2026	–	–	(22.3)	–	(22.3)
2027	–	–	(23.8)	–	(23.8)
2028	–	–	(25.8)	–	(25.8)
2029	–	–	(27.5)	–	(27.5)
2030	–	–	(29.6)	–	(29.6)
2031	–	–	(31.4)	–	(31.4)
2032	–	–	(33.5)	–	(33.5)
2033	–	–	(35.1)	–	(35.1)
2034	–	–	(37.2)	–	(37.2)
2035	–	–	(38.9)	–	(38.9)
2036	–	–	(41.1)	–	(41.1)
2037	–	–	(43.0)	–	(43.0)
2038	–	–	(45.5)	–	(45.5)
2039	–	–	(47.7)	–	(47.7)
2040	–	–	(50.5)	–	(50.5)
2041	–	–	(53.0)	–	(53.0)
2042	–	–	(55.9)	–	(55.9)
2043	–	–	(58.8)	–	(58.8)
2044	–	–	(62.5)	–	(62.5)
2045	–	–	(65.9)	–	(65.9)

Table J-18. Maui Island December 2016 PSIP Update versus April 2016 PSIP Update Sales Forecast Comparisons (GWh)

Lana'i December 2016 PSIP Update vs April 2016 PSIP Update Sales Forecast Comparisons

MWh	Underlying Forecast Differential	Energy Efficiency Differential	DG-PV Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	–	–	(0.3)	–	(0.3)
2017	–	–	(0.9)	–	(0.9)
2018	–	–	(1.0)	–	(1.0)
2019	–	–	(1.0)	–	(1.0)
2020	–	–	(1.0)	–	(1.0)
2021	–	–	(0.9)	–	(0.9)
2022	–	–	(0.9)	–	(0.9)
2023	–	–	(0.8)	–	(0.8)
2024	–	–	(0.7)	–	(0.7)
2025	–	–	(0.6)	–	(0.6)
2026	–	–	(0.6)	–	(0.6)
2027	–	–	(0.5)	–	(0.5)
2028	–	–	(0.5)	–	(0.5)
2029	–	–	(0.6)	–	(0.6)
2030	–	–	(0.6)	–	(0.6)
2031	–	–	(0.6)	–	(0.6)
2032	–	–	(0.7)	–	(0.7)
2033	–	–	(0.8)	–	(0.8)
2034	–	–	(0.8)	–	(0.8)
2035	–	–	(0.9)	–	(0.9)
2036	–	–	(0.9)	–	(0.9)
2037	–	–	(1.0)	–	(1.0)
2038	–	–	(1.2)	–	(1.2)
2039	–	–	(1.3)	–	(1.3)
2040	–	–	(1.3)	–	(1.3)
2041	–	–	(1.4)	–	(1.4)
2042	–	–	(1.5)	–	(1.5)
2043	–	–	(1.5)	–	(1.5)
2044	–	–	(1.7)	–	(1.7)
2045	–	–	(1.8)	–	(1.8)

Table J-19. Lana'i December 2016 PSIP Update versus April 2016 PSIP Update Sales Forecast Comparisons (MWh)

Moloka'i December 2016 PSIP Update vs April 2016 PSIP Update Sales Forecast Comparisons

MWh	Underlying Forecast Differential	Energy Efficiency Differential	DG-PV Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	–	–	(0.0)	–	(0.0)
2017	–	–	(0.4)	–	(0.4)
2018	–	–	(1.6)	–	(1.6)
2019	–	–	(1.8)	–	(1.8)
2020	–	–	(1.8)	–	(1.8)
2021	–	–	(2.0)	–	(2.0)
2022	–	–	(2.0)	–	(2.0)
2023	–	–	(1.9)	–	(1.9)
2024	–	–	(1.8)	–	(1.8)
2025	–	–	(1.8)	–	(1.8)
2026	–	–	(1.7)	–	(1.7)
2027	–	–	(1.7)	–	(1.7)
2028	–	–	(1.8)	–	(1.8)
2029	–	–	(1.9)	–	(1.9)
2030	–	–	(2.0)	–	(2.0)
2031	–	–	(2.1)	–	(2.1)
2032	–	–	(2.2)	–	(2.2)
2033	–	–	(2.3)	–	(2.3)
2034	–	–	(2.6)	–	(2.6)
2035	–	–	(2.7)	–	(2.7)
2036	–	–	(3.0)	–	(3.0)
2037	–	–	(3.2)	–	(3.2)
2038	–	–	(3.4)	–	(3.4)
2039	–	–	(3.7)	–	(3.7)
2040	–	–	(3.9)	–	(3.9)
2041	–	–	(4.1)	–	(4.1)
2042	–	–	(4.3)	–	(4.3)
2043	–	–	(4.6)	–	(4.6)
2044	–	–	(4.8)	–	(4.8)
2045	–	–	(5.0)	–	(5.0)

Table J-20. Moloka'i December 2016 PSIP Update versus April 2016 PSIP Update Sales Forecast Comparisons (MWh)

Hawai'i Island December 2016 PSIP Update vs April 2016 PSIP Update Sales Forecast Comparison

GWh	Underlying Forecast Differential	Energy Efficiency Differential	DG-PV Differential	Electric Vehicles Differential	Customer Level Sales Forecast Differential
Year	*a*	*b*	*c*	*d*	*e = a + b + c + d*
2016	–	–	0.4	–	0.4
2017	–	–	2.6	–	2.6
2018	–	–	1.0	–	1.0
2019	–	–	(0.5)	–	(0.5)
2020	–	–	(2.8)	–	(2.8)
2021	–	–	(4.8)	–	(4.8)
2022	–	–	(5.9)	–	(5.9)
2023	–	–	(7.9)	–	(7.9)
2024	–	–	(10.1)	–	(10.1)
2025	–	–	(12.3)	–	(12.3)
2026	–	–	(14.4)	–	(14.4)
2027	–	–	(16.1)	–	(16.1)
2028	–	–	(17.1)	–	(17.1)
2029	–	–	(18.8)	–	(18.8)
2030	–	–	(20.1)	–	(20.1)
2031	–	–	(22.0)	–	(22.0)
2032	–	–	(23.3)	–	(23.3)
2033	–	–	(25.2)	–	(25.2)
2034	–	–	(26.5)	–	(26.5)
2035	–	–	(28.3)	–	(28.3)
2036	–	–	(29.8)	–	(29.8)
2037	–	–	(31.7)	–	(31.7)
2038	–	–	(33.5)	–	(33.5)
2039	–	–	(35.6)	–	(35.6)
2040	–	–	(37.5)	–	(37.5)
2041	–	–	(39.9)	–	(39.9)
2042	–	–	(41.9)	–	(41.9)
2043	–	–	(44.6)	–	(44.6)
2044	–	–	(46.9)	–	(46.9)
2045	–	–	(49.9)	–	(49.9)

Table J-21. Hawai'i Island December 2016 PSIP Update versus April 2016 PSIP Update Sales Forecast Comparisons (GWh)

O'ahu DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	April 2016 PSIP Update	December 2016 PSIP Update	High DG-PV
Year	*MW*	*MW*	*MW*	*MW*
2016	447	445	407	407
2017	548	538	479	479
2018	572	563	520	520
2019	591	589	566	566
2020	608	610	606	606
2021	620	626	662	662
2022	631	639	680	690
2023	642	650	701	743
2024	652	661	722	805
2025	663	672	745	867
2026	674	683	769	928
2027	685	694	793	990
2028	696	705	817	1,052
2029	708	716	842	1,114
2030	720	727	869	1,175
2031	733	738	896	1,237
2032	747	749	925	1,299
2033	761	760	955	1,361
2034	776	771	985	1,422
2035	791	782	1,015	1,484
2036	808	793	1,046	1,546
2037	824	804	1,076	1,607
2038	841	815	1,106	1,669
2039	859	826	1,135	1,731
2040	877	837	1,163	1,793
2041	895	849	1,192	1,854
2042	914	860	1,220	1,916
2043	933	872	1,249	1,978
2044	952	884	1,278	2,040
2045	971	897	1,308	2,101

Table J-22. O'ahu DG-PV Forecast Cumulative Installed Capacity

Maui DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	April 2016 PSIP Update	December 2016 PSIP Update	High DG-PV
Year	*MW*	*MW*	*MW*	*MW*
2016	99	98	90	98
2017	117	115	113	115
2018	120	118	118	118
2019	123	122	125	125
2020	125	124	132	132
2021	126	126	136	136
2022	127	127	139	140
2023	127	128	141	153
2024	128	129	143	166
2025	129	130	144	178
2026	129	130	146	191
2027	130	131	148	204
2028	131	132	151	217
2029	132	133	153	230
2030	133	134	155	243
2031	134	135	157	255
2032	135	136	159	268
2033	136	137	162	281
2034	138	138	164	294
2035	139	139	166	307
2036	141	140	169	319
2037	143	142	171	332
2038	144	143	174	345
2039	146	144	177	358
2040	148	145	180	371
2041	150	147	183	384
2042	153	148	186	396
2043	155	150	189	409
2044	157	151	193	422
2045	160	153	197	435

Table J-23. Maui DG-PV Forecast Cumulative Installed Capacity

Lana'i DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	April 2016 PSIP Update	December 2016 PSIP Update	High DG-PV
Year	*MW*	*MW*	*MW*	*MW*
2016	0.7	0.6	0.8	0.8
2017	0.7	0.6	1.3	1.3
2018	0.8	0.6	1.4	1.4
2019	0.8	0.7	1.4	1.4
2020	0.9	0.7	1.5	1.5
2021	0.9	0.8	1.5	1.5
2022	1.0	0.9	1.5	1.7
2023	1.1	0.9	1.6	2.0
2024	1.1	1.0	1.6	2.3
2025	1.2	1.0	1.6	2.5
2026	1.2	1.1	1.6	2.8
2027	1.3	1.1	1.6	3.1
2028	1.3	1.2	1.6	3.3
2029	1.4	1.2	1.7	3.6
2030	1.4	1.2	1.7	3.8
2031	1.4	1.2	1.8	4.1
2032	1.4	1.2	1.9	4.4
2033	1.4	1.2	1.9	4.6
2034	1.4	1.2	1.9	4.9
2035	1.4	1.2	2.0	5.2
2036	1.4	1.2	2.0	5.4
2037	1.4	1.2	2.1	5.7
2038	1.4	1.2	2.2	6.0
2039	1.4	1.2	2.3	6.2
2040	1.4	1.2	2.3	6.5
2041	1.4	1.2	2.4	6.7
2042	1.4	1.2	2.4	7.0
2043	1.4	1.2	2.4	7.3
2044	1.4	1.2	2.6	7.5
2045	1.4	1.2	2.6	7.8

Table J-24. Lana'i DG-PV Forecast Cumulative Installed Capacity

Moloka'i DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	April 2016 PSIP Update	December 2016 PSIP Update	High DG-PV
Year	*MW*	*MW*	*MW*	*MW*
2016	2.6	2.2	2.0	2.1
2017	2.6	2.3	2.3	2.5
2018	2.7	2.3	3.0	3.1
2019	2.7	2.4	3.2	3.2
2020	2.9	2.5	3.4	3.4
2021	2.9	2.6	3.5	3.5
2022	3.0	2.6	3.5	3.6
2023	3.1	2.7	3.5	3.6
2024	3.1	2.7	3.5	3.8
2025	3.2	2.8	3.6	4.0
2026	3.3	2.9	3.6	4.1
2027	3.4	2.9	3.7	4.3
2028	3.5	3.0	3.8	4.4
2029	3.5	3.1	3.9	4.6
2030	3.6	3.2	4.0	4.7
2031	3.7	3.2	4.2	4.9
2032	3.8	3.3	4.3	5.0
2033	3.9	3.4	4.4	5.2
2034	3.9	3.4	4.6	5.4
2035	4.0	3.4	4.7	5.5
2036	4.0	3.5	4.9	5.7
2037	4.0	3.5	5.0	5.8
2038	4.0	3.5	5.1	6.0
2039	4.0	3.5	5.3	6.1
2040	4.0	3.5	5.4	6.3
2041	4.0	3.5	5.5	6.4
2042	4.0	3.5	5.7	6.6
2043	4.0	3.5	5.8	6.8
2044	4.0	3.5	6.0	6.9
2045	4.0	3.5	6.1	7.1

Table J-25. Moloka'i DG-PV Forecast Cumulative Installed Capacity

Hawai'i Island DG-PV Forecast Cumulative Installed Capacity

	February 2016 Interim Filing	April 2016 PSIP Update	December 2016 PSIP Update	High DG-PV
Year	*MW*	*MW*	*MW*	*MW*
2016	88	87	87	88
2017	102	101	99	103
2018	106	104	104	107
2019	109	108	108	111
2020	112	111	113	115
2021	115	114	117	119
2022	117	115	119	131
2023	118	117	122	145
2024	120	118	125	160
2025	122	119	127	174
2026	124	120	130	188
2027	125	122	133	202
2028	127	123	135	216
2029	129	125	137	230
2030	131	126	140	244
2031	133	127	142	258
2032	135	129	145	273
2033	137	130	147	287
2034	140	132	150	301
2035	142	133	152	315
2036	144	135	155	329
2037	147	136	158	343
2038	149	138	161	357
2039	152	140	164	372
2040	156	141	167	386
2041	159	143	170	400
2042	163	145	173	414
2043	168	146	176	428
2044	172	148	180	442
2045	178	150	184	456

Table J-26. Hawai'i Island DG-PV Forecast Cumulative Installed Capacity

O'ahu Self-Supply DESS Forecast Cumulative Installed Capacity

	December 2016 PSIP Update	High DG-PV
Year	*MWh*	*MWh*
2016	–	–
2017	3	3
2018	16	16
2019	35	35
2020	56	56
2021	70	70
2022	79	79
2023	89	89
2024	98	98
2025	108	111
2026	118	135
2027	128	160
2028	138	185
2029	148	211
2030	157	238
2031	168	266
2032	178	294
2033	190	324
2034	202	354
2035	213	384
2036	225	416
2037	235	448
2038	246	481
2039	255	515
2040	264	549
2041	273	585
2042	282	621
2043	290	657
2044	298	695
2045	306	733

Table J-27. O'ahu Self-Supply DESS Forecast Cumulative Installed Capacity

Maui Self-Supply DESS Forecast Cumulative Installed Capacity

	December 2016 PSIP Update	High DG-PV
Year	*MWh*	*MWh*
2016	–	–
2017	1	1
2018	3	3
2019	6	6
2020	9	9
2021	11	11
2022	12	12
2023	13	15
2024	14	20
2025	15	25
2026	16	31
2027	17	37
2028	18	43
2029	20	49
2030	21	55
2031	22	62
2032	23	68
2033	24	75
2034	26	82
2035	27	90
2036	28	97
2037	30	105
2038	31	112
2039	33	120
2040	34	128
2041	36	137
2042	38	145
2043	40	154
2044	42	163
2045	45	172

Table J-28. Maui Self-Supply DESS Forecast Cumulative Installed Capacity

Lana‘i Self-Supply DESS Forecast Cumulative Installed Capacity

	December 2016 PSIP Update	High DG-PV
Year	*MWh*	*MWh*
2016	–	–
2017	0.0	0.0
2018	0.0	0.0
2019	0.0	0.0
2020	0.0	0.0
2021	0.1	0.1
2022	0.1	0.2
2023	0.1	0.3
2024	0.1	0.4
2025	0.1	0.6
2026	0.1	0.8
2027	0.1	0.9
2028	0.1	1.1
2029	0.2	1.3
2030	0.2	1.5
2031	0.2	1.7
2032	0.3	1.9
2033	0.3	2.1
2034	0.3	2.3
2035	0.4	2.5
2036	0.4	2.7
2037	0.5	2.9
2038	0.5	3.2
2039	0.5	3.5
2040	0.6	3.7
2041	0.6	4.0
2042	0.6	4.2
2043	0.7	4.5
2044	0.7	4.7
2045	0.8	5.0

Table J-29. Lana‘i Self-Supply DESS Forecast Cumulative Installed Capacity

Moloka'i Self-Supply DESS Forecast Cumulative Installed Capacity

	December 2016 PSIP Update	High DG-PV
Year	*MWh*	*MWh*
2016	–	–
2017	0.0	0.0
2018	0.1	0.1
2019	0.2	0.2
2020	0.3	0.3
2021	0.3	0.3
2022	0.4	0.4
2023	0.4	0.4
2024	0.4	0.5
2025	0.4	0.6
2026	0.5	0.7
2027	0.5	0.9
2028	0.6	1.0
2029	0.7	1.2
2030	0.8	1.3
2031	1.0	1.4
2032	1.1	1.6
2033	1.2	1.7
2034	1.3	1.9
2035	1.5	2.0
2036	1.6	2.2
2037	1.7	2.3
2038	1.8	2.5
2039	2.0	2.7
2040	2.1	2.9
2041	2.2	3.0
2042	2.3	3.2
2043	2.4	3.4
2044	2.5	3.6
2045	2.6	3.7

Table J-30. Moloka'i Self-Supply DESS Forecast Cumulative Installed Capacity

Hawai'i Island Self-Supply DESS Forecast Cumulative Installed Capacity

	December 2016 PSIP Update	High DG-PV
Year	*MWh*	*MWh*
2016	–	–
2017	0	1
2018	2	2
2019	4	4
2020	6	6
2021	8	8
2022	9	12
2023	10	19
2024	12	26
2025	13	33
2026	14	41
2027	15	49
2028	17	57
2029	18	65
2030	19	74
2031	20	83
2032	22	92
2033	23	101
2034	25	111
2035	26	121
2036	27	131
2037	29	141
2038	30	152
2039	32	163
2040	33	174
2041	35	185
2042	36	196
2043	38	208
2044	40	220
2045	43	232

Table J-31. Hawai'i Island Self-Supply DESS Forecast Cumulative Installed Capacity

UHERO STATE OF HAWAI'I FORECASTS

State of Hawai'i 2014 and 2015 Non-Agricultural Job Forecasts

Year	2015 Outlook	2014 Outlook	% Difference (15/14)
2013	618,600	617,600	0.2%
2014	625,300	626,200	–0.1%
2015	634,500	636,900	–0.4%
2016	642,800	647,100	–0.7%
2017	649,500	655,700	–0.9%
2018	654,100	661,400	–1.1%
2019	657,200	664,100	–1.0%
2020	658,900	665,600	–1.0%
2021	660,100	668,400	–1.2%
2022	661,100	672,500	–1.7%
2023	663,000	677,100	–2.1%
2024	666,200	682,200	–2.3%
2025	671,500	687,300	–2.3%
2026	678,200	692,000	–2.0%
2027	685,000	696,400	–1.6%
2028	691,000	700,800	–1.4%
2029	695,600	705,200	–1.4%
2030	698,600	709,700	–1.6%

Table J-32. State of Hawai'i 2014 and 2015 Non-Agricultural Job Forecasts

State of Hawai'i 2014 and 2015 Real Personal Income per Capita Forecasts

Year	2015 Outlook	2014 Outlook	% Difference (15/14)
2013	17.8	18.0	–1.0%
2014	18.1	18.2	–0.9%
2015	18.4	18.7	–1.7%
2016	18.7	19.0	–1.7%
2017	18.9	19.2	–1.6%
2018	19.1	19.3	–1.3%
2019	19.2	19.3	–0.9%
2020	19.3	19.4	–0.6%
2021	19.3	19.4	–0.5%
2022	19.4	19.5	–0.6%
2023	19.5	19.6	–0.6%
2024	19.6	19.7	–0.5%
2025	19.8	19.8	–0.1%
2026	20.0	19.9	0.3%
2027	20.2	20.0	0.8%
2028	20.3	20.1	1.0%
2029	20.4	20.2	1.1%
2030	20.5	20.3	1.0%

Table J-33. State of Hawai'i 2014 and 2015 Real Personal Income per Capita Forecasts (thousands)

State of Hawaiʻi 2014 and 2015 Visitor Arrivals Forecasts

Year	2015 Outlook	2014 Outlook	% Difference (15/14)
2013	8,003.5	8,064.3	–0.8%
2014	8,159.6	8,141.6	0.2%
2015	8,233.5	8,268.7	–0.4%
2016	8,302.4	8,366.9	–0.8%
2017	8,345.6	8,447.7	–1.2%
2018	8,404.6	8,521.5	–1.4%
2019	8,439.8	8,591.6	–1.8%
2020	8,477.4	8,657.7	–2.1%
2021	8,524.9	8,720.6	–2.2%
2022	8,578.1	8,778.8	–2.3%
2023	8,636.4	8,832.1	–2.2%
2024	8,696.6	8,880.3	–2.1%
2025	8,758.0	8,923.4	–1.9%
2026	8,817.5	8,962.3	–1.6%
2027	8,866.8	8,998.3	–1.5%
2028	8,906.7	9,033.6	–1.4%
2029	8,936.5	9,069.1	–1.5%
2030	8,960.9	9,108.3	–1.6%

Table J-34. State of Hawaiʻi 2014 and 2015 Visitor Arrivals Forecasts (thousands)

RESOURCE CAPITAL COSTS

Resource costs and potential are key foundational assumptions for developing the PSIP. We have re-evaluated our resource costs since filing our April 2016 PSIP update.

New Resource Cost Assumptions: O'ahu

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$, without an Allowance for Funds Used During Construction (AFUDC)[7]

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): O'ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	< 10 kW	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O'ahu	O'ahu	Maui to O'ahu	Maui to O'ahu	O'ahu	O'ahu	O'ahu
2016	$2,215	$6,340	n/a	n/a	$2,293	$3,945	$12,304
2017	$2,254	$6,255	n/a	n/a	$2,127	$3,716	$12,525
2018	$2,193	$6,165	n/a	n/a	$2,047	$3,573	$11,681
2019	$2,178	$6,070	n/a	n/a	$1,984	$3,457	$10,781
2020	$2,230	$5,969	$4,847	$4,322	$1,932	$3,360	$9,848
2021	$2,520	$5,880	$5,207	$4,672	$1,892	$3,285	$8,874
2022	$2,586	$5,720	$5,324	$4,778	$2,099	$3,218	$7,867
2023	$2,644	$5,553	$5,456	$4,899	$2,064	$3,160	$7,813
2024	$2,691	$5,571	$5,560	$4,992	$2,035	$3,111	$7,756
2025	$2,722	$5,587	$5,664	$5,085	$2,012	$3,068	$7,694
2026	$2,753	$5,602	$5,758	$5,166	$1,995	$3,034	$7,627
2027	$2,773	$5,616	$5,851	$5,248	$1,980	$3,004	$7,555
2028	$2,805	$5,629	$5,948	$5,333	$1,966	$2,976	$7,478
2029	$2,830	$5,640	$6,049	$5,422	$1,955	$2,952	$7,396
2030	$2,867	$5,650	$6,154	$5,514	$1,946	$2,933	$7,309

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-35. Replacement Resource Capital Cost Assumptions: O'ahu 2016–2030 (1a of 2)

[7] Solar PV costs are typically quoted based on the price per kW of Direct Current (DC) output (that is, the total capacity of the PV panels). These utility-scale solar PV costs has been converted to the price per kW of Alternating Current (AC) output supplied to the grid using a DC to AC 1.5:1 ratio.

New Resource Cost Assumptions: O‘ahu (1b of 2)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): O‘ahu						
Technology	Onshore Wind*	Offshore Wind Floating Platform*	Onshore Wind + Cable*	Onshore Wind + Cable*	Utility-Scale Solar PV*	Solar DG-PV	CSP w/ 10 Hours Storage
Size (MW)	30	400	200	400	20	< 10 kW	100
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS Energy RSMeans	NREL	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans Vendor Quotes	IHS Energy RSMeans	IHS Energy RSMeans	NREL
Island	O‘ahu	O‘ahu	Maui to O‘ahu	Maui to O‘ahu	O‘ahu	O‘ahu	O‘ahu
2031	$2,891	$5,705	$6,257	$5,604	$1,937	$2,925	$7,216
2032	$2,925	$5,760	$6,362	$5,696	$1,928	$2,917	$7,117
2033	$2,949	$5,815	$6,468	$5,789	$1,920	$2,910	$7,245
2034	$2,984	$5,871	$6,577	$5,884	$1,910	$2,902	$7,375
2035	$3,010	$5,926	$6,688	$5,981	$1,902	$2,894	$7,508
2036	$3,045	$5,982	$6,800	$6,079	$1,893	$2,887	$7,643
2037	$3,071	$6,037	$6,915	$6,179	$1,884	$2,879	$7,781
2038	$3,107	$6,093	$7,031	$6,281	$1,875	$2,872	$7,921
2039	$3,134	$6,149	$7,150	$6,385	$1,867	$2,864	$8,064
2040	$3,171	$6,205	$7,270	$6,490	$1,857	$2,856	$8,209
2041	$3,199	$6,266	$7,393	$6,598	$1,849	$2,849	$8,356
2042	$3,237	$6,328	$7,518	$6,707	$1,839	$2,841	$8,507
2043	$3,265	$6,390	$7,646	$6,818	$1,831	$2,834	$8,660
2044	$3,303	$6,452	$7,775	$6,931	$1,821	$2,827	$8,816
2045	$3,333	$6,514	$7,907	$7,046	$1,813	$2,819	$8,975

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-36. Replacement Resource Capital Cost Assumptions: O‘ahu 2031–2045 (1b of 2)

New Resource Cost Assumptions: O'ahu (2a of 2)

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): O'ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O'ahu	O'ahu	O'ahu	O'ahu, Maui, Hawai'i Island	O'ahu, Maui, Hawai'i Island	O'ahu, Maui, Hawai'i Island	O'ahu
2016	$1,758	$1,660	$1,237	$6,296	$3,177	$2,493	$1,323
2017	$1,783	$1,683	$1,253	$6,092	$3,219	$2,526	$1,347
2018	$1,797	$1,697	$1,261	$6,178	$3,238	$2,541	$1,371
2019	$1,822	$1,720	$1,277	$6,269	$3,280	$2,574	$1,396
2020	$1,845	$1,742	$1,292	$6,354	$3,319	$2,604	$1,421
2021	$1,870	$1,766	$1,309	$6,446	$3,362	$2,638	$1,447
2022	$1,896	$1,790	$1,326	$6,541	$3,406	$2,672	$1,473
2023	$1,921	$1,813	$1,342	$6,633	$3,448	$2,705	$1,499
2024	$1,944	$1,836	$1,358	$6,725	$3,487	$2,736	$1,526
2025	$1,969	$1,859	$1,373	$6,826	$3,527	$2,768	$1,554
2026	$1,992	$1,881	$1,388	$6,918	$3,564	$2,797	$1,582
2027	$2,021	$1,909	$1,408	$7,019	$3,617	$2,838	$1,610
2028	$2,051	$1,937	$1,428	$7,121	$3,668	$2,878	$1,639
2029	$2,079	$1,963	$1,447	$7,222	$3,716	$2,916	$1,669
2030	$2,108	$1,991	$1,466	$7,323	$3,766	$2,955	$1,699

Table J-37. Replacement Resource Capital Cost Assumptions: O'ahu 2016–2030 (2a of 2)

New Resource Cost Assumptions: O‘ahu (2b of 2)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$, without AFUDC

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): O‘ahu						
Technology	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
Size (MW)	383 (3 x 1)	152 (1 x 1)	100	20	27 (3 x 9 MW)	54 (6 x 9 MW)	100 (6 x 16.8 MW) Power Barge
Fuel	Gas / Oil	Gas / Oil	Gas / Oil	Biomass	Gas / Oil	Gas / Oil	Gas / Oil
Source	NextEra	NextEra	Gas Turbine World RSMeans	NREL	Hawaiian Electric	Hawaiian Electric Schofield Application	Hawaiian Electric
Island	O‘ahu	O‘ahu	O‘ahu	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu, Maui, Hawai‘i Island	O‘ahu
2031	$2,139	$2,019	$1,487	$7,425	$3,819	$2,997	$1,729
2032	$2,169	$2,048	$1,507	$7,528	$3,872	$3,038	$1,761
2033	$2,202	$2,079	$1,530	$7,638	$3,930	$3,083	$1,792
2034	$2,234	$2,110	$1,552	$7,743	$3,986	$3,127	$1,825
2035	$2,270	$2,143	$1,577	$7,850	$4,050	$3,178	$1,857
2036	$2,304	$2,176	$1,601	$7,952	$4,112	$3,226	$1,891
2037	$2,342	$2,211	$1,627	$8,062	$4,179	$3,279	$1,925
2038	$2,379	$2,246	$1,653	$8,166	$4,246	$3,331	$1,959
2039	$2,419	$2,284	$1,681	$8,267	$4,317	$3,387	$1,995
2040	$2,455	$2,318	$1,706	$8,361	$4,382	$3,439	$2,031
2041	$2,499	$2,360	$1,737	$8,512	$4,461	$3,501	$2,067
2042	$2,544	$2,403	$1,768	$8,665	$4,542	$3,564	$2,104
2043	$2,590	$2,446	$1,800	$8,821	$4,623	$3,628	$2,142
2044	$2,637	$2,490	$1,832	$8,979	$4,707	$3,693	$2,181
2045	$2,684	$2,535	$1,865	$9,141	$4,791	$3,760	$2,220

Table J-38. Replacement Resource Capital Cost Assumptions: O‘ahu 2031–2045 (2b of 2)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island

Hawai'i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): Maui, Lana'i, Moloka'i, Hawai'i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui	Lana'i Moloka'i	Lana'i Moloka'i	Hawai'i Maui	Hawai'i Maui	Hawai'i Maui
2016	$3,921	$2,718	$2,215	$3,510	$3,523	$2,762	$2,349	$2,074
2017	$3,987	$2,765	$2,254	$3,603	$3,283	$2,568	$2,180	$1,921
2018	$3,884	$2,691	$2,193	$4,111	$3,169	$2,476	$2,099	$1,848
2019	$3,858	$2,673	$2,178	$4,380	$3,077	$2,401	$2,034	$1,789
2020	$3,948	$2,737	$2,230	$4,803	$3,003	$2,341	$1,981	$1,741
2021	$4,266	$3,035	$2,520	$5,588	$2,946	$2,295	$1,941	$1,705
2022	$4,377	$3,114	$2,586	$5,734	$3,056	$2,414	$2,066	$1,833
2023	$4,475	$3,184	$2,644	$5,916	$3,018	$2,384	$2,040	$1,810
2024	$4,553	$3,240	$2,691	$6,020	$2,987	$2,360	$2,019	$1,792
2025	$4,606	$3,277	$2,722	$6,122	$2,961	$2,340	$2,002	$1,776
2026	$4,659	$3,315	$2,753	$6,192	$2,943	$2,325	$1,989	$1,765
2027	$4,693	$3,339	$2,773	$6,258	$2,926	$2,312	$1,978	$1,755
2028	$4,747	$3,377	$2,805	$6,330	$2,913	$2,301	$1,969	$1,747
2029	$4,789	$3,407	$2,830	$6,410	$2,902	$2,292	$1,961	$1,740
2030	$4,853	$3,453	$2,867	$6,495	$2,894	$2,286	$1,956	$1,736

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-39. Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island 2016–2030 (1a of 2)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (1b of 2)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): Maui, Lana‘i, Moloka‘i, Hawai‘i Island							
Technology	Onshore Wind*	Onshore Wind*	Onshore Wind*	Onshore Wind*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*	Utility-Scale Solar PV*
Size (MW)	10	20	30	1 (10 x 100 kW)	1	5	10	20
Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Source	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	Indicative quote from NPS + install estimate	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans	IHS, RSMeans
Island	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui	Lana‘i Moloka‘i	Lana‘i Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Hawai‘i Maui
2031	$4,892	$3,481	$2,891	$6,571	$2,886	$2,280	$1,951	$1,731
2032	$4,950	$3,522	$2,925	$6,649	$2,879	$2,274	$1,946	$1,727
2033	$4,992	$3,552	$2,949	$6,727	$2,871	$2,268	$1,941	$1,722
2034	$5,051	$3,594	$2,984	$6,807	$2,864	$2,262	$1,936	$1,718
2035	$5,093	$3,624	$3,010	$6,887	$2,856	$2,256	$1,931	$1,713
2036	$5,154	$3,667	$3,045	$6,968	$2,849	$2,250	$1,925	$1,709
2037	$5,198	$3,698	$3,071	$7,051	$2,841	$2,244	$1,920	$1,704
2038	$5,259	$3,742	$3,107	$7,134	$2,834	$2,239	$1,915	$1,700
2039	$5,304	$3,774	$3,134	$7,218	$2,826	$2,233	$1,910	$1,695
2040	$5,367	$3,819	$3,171	$7,303	$2,819	$2,227	$1,905	$1,691
2041	$5,414	$3,852	$3,199	$7,389	$2,811	$2,221	$1,900	$1,686
2042	$5,478	$3,897	$3,237	$7,477	$2,804	$2,215	$1,895	$1,682
2043	$5,525	$3,931	$3,265	$7,565	$2,796	$2,209	$1,890	$1,677
2044	$5,591	$3,978	$3,303	$7,654	$2,789	$2,203	$1,885	$1,673
2045	$5,640	$4,013	$3,333	$7,744	$2,782	$2,198	$1,880	$1,669

* = Amounts have been reduced by the $500,000 state tax credit cap

Table J-40. Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2031–2045 (1b of 2)

New Resource Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island (2a of 2)

Hawai‘i specific nominal overnight capital cost $/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): Maui, Lana‘i, Moloka‘i, Hawai‘i Island						
Technology	Solar DG-PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	Varies	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai‘i, Maui, Lana‘i, Moloka‘i	Hawai‘i Maui	Lana‘i, Moloka‘i	Hawai‘i Maui	Hawai‘i Maui	Lana‘i, Moloka‘i	Hawai‘i Maui
2016	$3,985	$3,586	$8,334	$6,296	$8,804	$10,394	$5,407
2017	$3,753	$3,634	$8,064	$6,092	$8,963	$10,532	$5,479
2018	$3,609	$3,655	$8,179	$6,178	$9,124	$10,593	$5,510
2019	$3,492	$3,702	$8,298	$6,269	$9,289	$10,731	$5,582
2020	$3,394	$3,747	$8,411	$6,354	$9,456	$10,859	$5,649
2021	$3,318	$3,795	$8,533	$6,446	$9,626	$11,000	$5,722
2022	$3,251	$3,844	$8,659	$6,541	$9,799	$11,142	$5,796
2023	$3,192	$3,892	$8,781	$6,633	$9,976	$11,280	$5,868
2024	$3,142	$3,936	$8,902	$6,725	$10,155	$11,408	$5,935
2025	$3,100	$3,981	$9,036	$6,826	$10,338	$11,540	$6,003
2026	$3,065	$4,023	$9,158	$6,918	$10,524	$11,661	$6,066
2027	$3,034	$4,082	$9,291	$7,019	$10,713	$11,832	$6,155
2028	$3,007	$4,140	$9,427	$7,121	$10,906	$12,000	$6,243
2029	$2,982	$4,194	$9,560	$7,222	$11,103	$12,157	$6,324
2030	$2,962	$4,251	$9,694	$7,323	$11,302	$12,322	$6,410

Table J-41. Replacement Resource Capital Cost Assumptions: Maui, Lana‘i, Moloka‘i, Hawai‘i Island 2016–2030 (2a of 2)

New Resource Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island (2b of 2)

Hawai'i specific nominal overnight capital cost \$/kW$_{AC}$ (without AFUDC)

Nominal $/kW	Replacement Resource Capital Cost Assumptions (without AFUDC): Maui, Lana'i, Moloka'i, Hawai'i Island						
Technology	Solar DG-PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
Size (MW)	Varies	20.5	1	20	20	1	9
Fuel	n/a	Gas / Oil	Biomass	Biomass	n/a	Oil	Gas / Oil
Source	IHS, RSMeans	NextEra	HECO Research of Comparable Plants	NREL	NREL	NextEra	NextEra
Island	Hawai'i, Maui, Lana'i, Moloka'i	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui	Hawai'i Maui	Lana'i, Moloka'i	Hawai'i Maui
2031	$2,955	$4,311	$9,829	$7,425	$11,506	$12,494	$6,500
2032	$2,947	$4,371	$9,966	$7,528	$11,713	$12,668	$6,590
2033	$2,939	$4,436	$10,111	$7,638	$11,924	$12,856	$6,688
2034	$2,931	$4,499	$10,250	$7,743	$12,138	$13,040	$6,783
2035	$2,924	$4,571	$10,391	$7,850	$12,357	$13,250	$6,893
2036	$2,916	$4,641	$10,527	$7,952	$12,579	$13,453	$6,998
2037	$2,908	$4,717	$10,673	$8,062	$12,806	$13,672	$7,112
2038	$2,901	$4,792	$10,810	$8,166	$13,036	$13,890	$7,226
2039	$2,893	$4,873	$10,944	$8,267	$13,271	$14,123	$7,347
2040	$2,885	$4,947	$11,068	$8,361	$13,510	$14,338	$7,459
2041	$2,878	$5,036	$11,267	$8,512	$13,753	$14,596	$7,593
2042	$2,870	$5,126	$11,470	$8,665	$14,001	$14,859	$7,730
2043	$2,863	$5,219	$11,677	$8,821	$14,253	$15,126	$7,869
2044	$2,855	$5,313	$11,887	$8,979	$14,509	$15,398	$8,010
2045	$2,848	$5,408	$12,101	$9,141	$14,770	$15,676	$8,154

Table J-42. Replacement Resource Capital Cost Assumptions: Maui, Lana'i, Moloka'i, Hawai'i Island 2031–2045 (2b of 2)

Replacement Resource Construction Expenditure Profiles: O'ahu

	Replacement Resource Construction Expenditure Profiles: O'ahu						
Years Before Commercial Operation Date	Onshore Wind	Offshore Wind Floating Platform	Onshore Wind + Cable	Onshore Wind + Cable	Utility-Scale Solar PV	Solar DG-PV	CSP w/ 10 Hours Storage
–5	00%	00%	00%	00%	00%	n/a	00%
–4	00%	00%	00%	00%	00%	n/a	00%
–3	00%	20%	20%	20%	00%	n/a	00%
–2	10%	40%	40%	40%	10%	n/a	10%
–1	90%	40%	40%	40%	90%	n/a	90%
Total COD	100%	100%	100%	100%	100%	n/a	100%

Table J-43. Replacement Resource Construction Expenditure Profiles: O'ahu (1 of 2)

	Replacement Resource Construction Expenditure Profiles: O'ahu						
Years Before Commercial Operation Date	Combined Cycle Gas	Combined Cycle Gas	Simple Cycle Gas	Biomass	Internal Combustion	Internal Combustion	Internal Combustion
–5	00%	00%	00%	00%	00%	00%	00%
–4	15%	10%	00%	00%	00%	00%	00%
–3	35%	35%	15%	00%	15%	15%	00%
–2	35%	40%	65%	10%	65%	65%	65%
–1	15%	15%	20%	90%	20%	20%	35%
Total COD	100%	100%	100%	100%	100%	100%	100%

Table J-44. Replacement Resource Construction Expenditure Profiles: O'ahu (2 of 2)

Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island

	Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island							
Years Before Commercial Operation Date	Onshore Wind	Onshore Wind	Onshore Wind	Onshore Wind	Utility-Scale Solar PV	Utility-Scale Solar PV	Utility-Scale Solar PV	Utility-Scale Solar PV
–5	00%	00%	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%	00%	00%
–2	10%	10%	10%	00%	00%	10%	10%	10%
–1	90%	90%	90%	100%	100%	90%	90%	90%
Total COD	100%	100%	100%	100%	100%	100%	100%	100%

Table J-45. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (1 of 2)

	Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island						
Years Before Commercial Operation Date	Solar DG-PV	Simple Cycle Gas	Biomass	Biomass	Geothermal	Internal Combustion	Internal Combustion
–5	n/a	00%	00%	00%	00%	00%	00%
–4	n/a	00%	00%	00%	00%	00%	00%
–3	n/a	20%	25%	20%	00%	25%	20%
–2	n/a	65%	60%	65%	40%	60%	65%
–1	n/a	15%	15%	15%	60%	15%	15%
Total COD	n/a	100%	100%	100%	100%	100%	100%

Table J-46. Replacement Resource Construction Expenditure Profiles: Maui, Lana'i, Moloka'i, Hawai'i Island (2 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium-Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15%	15				
2016	$9,400	$1,506	$1,506	$1,506	$1,506	$1,506
2017	$8,632	$1,383	$1,383	$1,383	$1,383	$1,383
2018	$7,877	$1,262	$1,262	$1,262	$1,262	$1,262
2019	$7,253	$1,162	$1,162	$1,162	$1,162	$1,162
2020	$6,729	$1,078	$1,078	$1,078	$1,078	$1,078
2021	$6,317	$1,012	$1,012	$1,012	$1,012	$1,012
2022	$5,972	$957	$957	$957	$957	$957
2023	$5,678	$910	$910	$910	$910	$910
2024	$5,429	$870	$870	$870	$870	$870
2025	$5,214	$835	$835	$835	$835	$835
2026	$5,029	$806	$806	$806	$806	$806
2027	$4,869	$780	$780	$780	$780	$780
2028	$4,730	$758	$758	$758	$758	$758
2029	$4,609	$738	$738	$738	$738	$738
2030	$4,503	$721	$721	$721	$721	$721

Table J-47. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Inertia and Contingency Applications (2 of 2)

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Size (MW)	10	1	5	20	50	100
Technology	Flywheel	Lithium-Ion				
Duration Hours	0.25	0.5				
Turnaround Efficiency	85%	81%				
Discharge Cycles Per Year	15,000	Up to 10				
Depth of Discharge	100%	Up to 100%				
Plant Life Years	15%	15				
2031	$4,409	$706	$706	$706	$706	$706
2032	$4,327	$693	$693	$693	$693	$693
2033	$4,255	$682	$682	$682	$682	$682
2034	$4,190	$671	$671	$671	$671	$671
2035	$4,133	$662	$662	$662	$662	$662
2036	$4,083	$654	$654	$654	$654	$654
2037	$4,038	$647	$647	$647	$647	$647
2038	$3,998	$641	$641	$641	$641	$641
2039	$3,962	$635	$635	$635	$635	$635
2040	$3,930	$630	$630	$630	$630	$630
2041	$3,902	$625	$625	$625	$625	$625
2042	$3,876	$621	$621	$621	$621	$621
2043	$3,854	$617	$617	$617	$617	$617
2044	$3,833	$614	$614	$614	$614	$614
2045	$3,815	$611	$611	$611	$611	$611

Table J-48. Energy Storage Cost Assumptions: Inertia and Contingency Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications				
Size (MW)	1	5	20	50	100
Technology	Lithium-Ion				
Duration Hours	1.0				
Turnaround Efficiency	81%				
Discharge Cycles Per Year	Up to 15,000				
Depth of Discharge	Up to 20%				
Plant Life Years	15				
2016	$1,083	$1,083	$1,083	$1,083	$1,083
2017	$999	$999	$999	$999	$999
2018	$914	$914	$914	$914	$914
2019	$843	$843	$843	$843	$843
2020	$782	$782	$782	$782	$782
2021	$737	$737	$737	$737	$737
2022	$698	$698	$698	$698	$698
2023	$666	$666	$666	$666	$666
2024	$638	$638	$638	$638	$638
2025	$614	$614	$614	$614	$614
2026	$594	$594	$594	$594	$594
2027	$576	$576	$576	$576	$576
2028	$560	$560	$560	$560	$560
2029	$547	$547	$547	$547	$547
2030	$535	$535	$535	$535	$535

Table J-49. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications (2 of 2)

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications				
Size (MW)	1	5	20	50	100
Technology	Lithium-Ion				
Duration Hours	1.0				
Turnaround Efficiency	81%				
Discharge Cycles Per Year	Up to 15,000				
Depth of Discharge	Up to 20%				
Plant Life Years	15				
2031	$525	$525	$525	$525	$525
2032	$516	$516	$516	$516	$516
2033	$508	$508	$508	$508	$508
2034	$500	$500	$500	$500	$500
2035	$494	$494	$494	$494	$494
2036	$488	$488	$488	$488	$488
2037	$483	$483	$483	$483	$483
2038	$479	$479	$479	$479	$479
2039	$475	$475	$475	$475	$475
2040	$471	$471	$471	$471	$471
2041	$468	$468	$468	$468	$468
2042	$465	$465	$465	$465	$465
2043	$463	$463	$463	$463	$463
2044	$461	$461	$461	$461	$461
2045	$459	$459	$459	$459	$459

Table J-50. Energy Storage Cost Assumptions: Regulation / Renewable Smoothing Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications					
Application	Load Shifting					Grid Support
Size (MW)	1	5	20	50	100	5
Technology	Lithium-Ion					Lithium-Ion
Duration Hours	4.0					2.0
Turnaround Efficiency	88%					81%
Discharge Cycles Per Year	Up to 365					Up to 365
Depth of Discharge	Up to 100%					Up to 100%
Plant Life Years	15					15
2016	$660	$660	$660	$660	$660	$1,083
2017	$615	$615	$615	$615	$615	$999
2018	$565	$565	$565	$565	$565	$914
2019	$524	$524	$524	$524	$524	$843
2020	$487	$487	$487	$487	$487	$782
2021	$461	$461	$461	$461	$461	$737
2022	$440	$440	$440	$440	$440	$698
2023	$422	$422	$422	$422	$422	$666
2024	$406	$406	$406	$406	$406	$638
2025	$393	$393	$393	$393	$393	$614
2026	$382	$382	$382	$382	$382	$594
2027	$372	$372	$372	$372	$372	$576
2028	$363	$363	$363	$363	$363	$560
2029	$355	$355	$355	$355	$355	$547
2030	$349	$349	$349	$349	$349	$535

Table J-51. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications (2 of 2)

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications					
Application	Load Shifting					Grid Support
Size (MW)	1	5	20	50	100	5
Technology	Lithium-Ion					Lithium-Ion
Duration Hours	4.0					2.0
Turnaround Efficiency	88%					81%
Discharge Cycles Per Year	Up to 365					Up to 365
Depth of Discharge	Up to 100%					Up to 100%
Plant Life Years	15					15
2031	$343	$343	$343	$343	$343	$525
2032	$338	$338	$338	$338	$338	$516
2033	$333	$333	$333	$333	$333	$508
2034	$329	$329	$329	$329	$329	$500
2035	$326	$326	$326	$326	$326	$494
2036	$323	$323	$323	$323	$323	$488
2037	$320	$320	$320	$320	$320	$483
2038	$317	$317	$317	$317	$317	$479
2039	$315	$315	$315	$315	$315	$475
2040	$313	$313	$313	$313	$313	$471
2041	$312	$312	$312	$312	$312	$468
2042	$310	$310	$310	$310	$310	$465
2043	$309	$309	$309	$309	$309	$463
2044	$307	$307	$307	$307	$307	$461
2045	$306	$306	$306	$306	$306	$459

Table J-52. Energy Storage Cost Assumptions: Load Shifting and Grid Support Applications 2031–2045 (2 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050	1.000	30.000	30.000	50.000
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	
2016	$506	$1,026	$553	$553	$530	$583	$583
2017	$465	$961	$511	$511	$493	$594	$594
2018	$416	$884	$461	$461	$454	$605	$605
2019	$373	$817	$417	$417	$421	$615	$615
2020	$335	$757	$378	$378	$391	$626	$626
2021	$317	$729	$359	$359	$371	$638	$638
2022	$303	$706	$342	$342	$353	$649	$649
2023	$290	$687	$328	$328	$339	$661	$661
2024	$280	$670	$316	$316	$326	$673	$673
2025	$270	$655	$305	$305	$316	$685	$685
2026	$262	$643	$296	$296	$306	$697	$697
2027	$256	$632	$289	$289	$298	$710	$710
2028	$250	$623	$282	$282	$291	$723	$723
2029	$245	$615	$276	$276	$285	$736	$736
2030	$240	$608	$271	$271	$280	$749	$749

Table J-53. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2016–2030 (1 of 2)

Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications (2 of 2)

Capital cost in nominal $/kWh (without AFUDC or interconnection costs)

Nominal $/kWh	Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Size (MW)	0.002		0.050	1.000	30.000	30.000	50.000
Technology	Lithium-Ion w/o inverter	Lithium-Ion w/ inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Duration Hours	4.0		2.0		6.0		
Turnaround Efficiency	88%		88%		80%		
Discharge Cycles Per Year	Up to 365		Up to 365		Up to 365		
Depth of Discharge	Up to 100%		Up to 100%		Up to 100%		
Plant Life Years	10		10		15	40	
2031	$236	$601	$267	$267	$275	$762	$762
2032	$232	$596	$263	$263	$271	$776	$776
2033	$229	$591	$259	$259	$268	$790	$790
2034	$227	$587	$256	$256	$264	$804	$804
2035	$224	$583	$253	$253	$262	$819	$819
2036	$222	$579	$251	$251	$259	$833	$833
2037	$220	$576	$249	$249	$257	$848	$848
2038	$218	$574	$247	$247	$255	$864	$864
2039	$217	$571	$245	$245	$253	$879	$879
2040	$216	$569	$243	$243	$252	$895	$895
2041	$214	$567	$242	$242	$250	$911	$911
2042	$213	$565	$241	$241	$249	$928	$928
2043	$212	$564	$240	$240	$248	$944	$944
2044	$211	$563	$239	$239	$247	$961	$961
2045	$211	$561	$238	$238	$246	$979	$979

Table J-54. Energy Storage Cost Assumptions: Residential, Commercial, and Long Duration Load Shifting Applications 2030–2045 (2 of 2)

Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications					
Application	Inertia	Contingency				
Years Before Commercial Operation Date	10 MW	1 MW	5 MW	20 MW	50 MW	100 MW
–6	00%	00%	00%	00%	00%	00%
–5	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%
–2	20%	00%	00%	20%	20%	20%
–1	80%	100%	100%	80%	80%	80%
Total COD	100%	100%	100%	100%	100%	100%

Table J-55. Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications

Energy Storage Construction Expenditure Profiles: Regulation/Renewable Smoothing Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Inertia and Contingency Applications				
Application	Regulation/Renewable Smoothing				
Years Before Commercial Operation Date	1 MW	5 MW	20 MW	50 MW	100 MW
–6	00%	00%	00%	00%	00%
–5	0%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%
–2	00%	00%	20%	20%	20%
–1	100%	100%	80%	80%	80%
Total COD	100%	100%	100%	100%	100%

Table J-56. Energy Storage Construction Expenditure Profiles: Regulation/Renewable Smoothing Applications

Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications

All costs are for lithium-ion batteries.

	Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications					
Application	Load Shifting					Grid Support
Years Before Commercial Operation Date	1 MW	5 MW	20 MW	50 MW	100 MW	5 MW
–6	00%	00%	00%	00%	00%	00%
–5	00%	00%	00%	00%	00%	00%
–4	00%	00%	00%	00%	00%	00%
–3	00%	00%	00%	00%	00%	00%
–2	00%	00%	20%	20%	30%	00%
–1	100%	100%	80%	80%	70%	100%
Total COD	100%	100%	100%	100%	100%	100%

Table J-57. Energy Storage Construction Expenditure Profiles: Load Shifting and Grid Support Applications

Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications

	Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications						
Application	Residential		Commercial		Long Duration Load Shifting		
Technology	Lithium-Ion w/o Inverter	Lithium-Ion w/ Inverter & Balance of Plant	Lithium-Ion		Lithium-Ion	Pumped-Storage Hydro	
Years Before Commercial Operation Date	0.002 MW		0.050 MW		30.000 MW		50.000 MW
–6	n/a	n/a	n/a	n/a	00%	5%	5%
–5	n/a	n/a	n/a	n/a	00%	10%	10%
–4	n/a	n/a	n/a	n/a	00%	10%	10%
–3	n/a	n/a	n/a	n/a	00%	20%	20%
–2	n/a	n/a	n/a	n/a	30%	30%	30%
–1	n/a	n/a	n/a	n/a	70%	25%	25%
Total COD	n/a	n/a	n/a	n/a	100%	100%	100%

Table J-58. Energy Storage Construction Expenditure Profiles: Residential, Commercial, and Long Duration Load Shifting Applications

DEMAND RESPONSE DATA

The Black & Veatch AP for Production Simulation model produces Demand Response (DR) modeling data to evaluate DR for reducing energy production costs, deferring capital expenditures, and improving grid stability. There are a number of key inputs and constraints unique to the Demand Response modeling data.

The primary modeling data assumptions originated from the Navigant Potential Study. The study forecasted the quantity of MW by customer class and end use device that the Companies can target in each DR program.

The end uses are identified in the following tables. Table J-59 lists the DR end uses for residential customers; Table J-60 lists the DR end uses for commercial, industrial, and small business customers.

Building Type	End Uses
Electric Vehicles	EV
Photovoltaics	PV
Residential	Cooling, water heating, and other
Storage	Storage paired with PV and Standalone Storage

Table J-59. DR End Uses for Residential Customers

Customer Storage is an End Use for Residential customers, as well as other building types. Storage was not forecasted in the gross load profile. In the interim DR filing, the gross load profile did include customer storage, but the PSIP modeling assumed no customer storage as the base case, the case to build on. BCG has created a econometrics model to better forecast customer uptake of customer storage based on the customers payback period, provided DR incentives or reduced price and other state and federal incentives. The forecasted number for customer storage is added into each DR portfolio case, but because each case is different, we were not able to consistently settle on one case for DR or storage. Once all inputs for the Preferred Case are accepted, the forecasted Customer Storage potential will be locked in with the entire DR portfolio potential.

Building Type	End Uses
Storage	Storage paired with PV and Standalone Storage
Education	Cooling, lighting, ventilation, water heating, and other
Electric Vehicles	EV
Grocery	Cooling, lighting, ventilation, water heating, and other
Health	Cooling, lighting, ventilation, water heating, and other
Hotel	Cooling, lighting, ventilation, water heating, and other
Industrial	Whole facility
Large Multi-Family	Cooling, lighting, water heating, and other
Military	Cooling, heating, lighting, ventilation, water heating, and other
Office	Cooling, heating, lighting, ventilation, water heating, and other
Photovoltaics	PV
Restaurant	Cooling, lighting, ventilation, water heating, and other
Retail	Cooling, heating, lighting, ventilation, water heating, and other
Warehouse	Whole facility
Water Pumping	Whole facility

Table J-60. DR End Uses for Commercial, Industrial, and Small Business Customers

The Navigant Potential Study determined the maximum achievable potential of end-use devices to provide specific services (fast frequency response, non-spin auto response, regulating reserves, load building, and load reduction) through specific DR programs (time of use, day ahead load shift, real-time pricing, critical peak incentive, minimum load building, fast frequency response, non-spin auto response, and regulating reserves). AP for Production Simulation uses annual weekday and weekend potential data by DR program, customer class, building type, and end use. Figure J-33 shows the potential, under available programs, to decrease load using the cooling end use available from military buildings on O'ahu. It is a snapshot based on a weekday during September 2030.

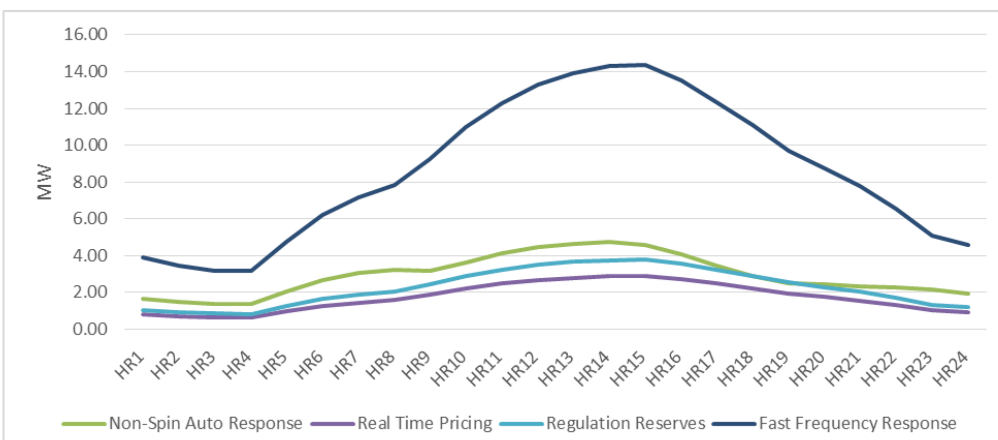


Figure J-33. Example Load Decrease Potential Supporting DR Programs

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

In general, DR programs grow over time. Figure J-34 shows how Regulation Reserves potential considering all customer classes and all end uses on O'ahu is expected to increase between 2018 (the first year available) and 2045. This data also represents a September weekday snapshot.

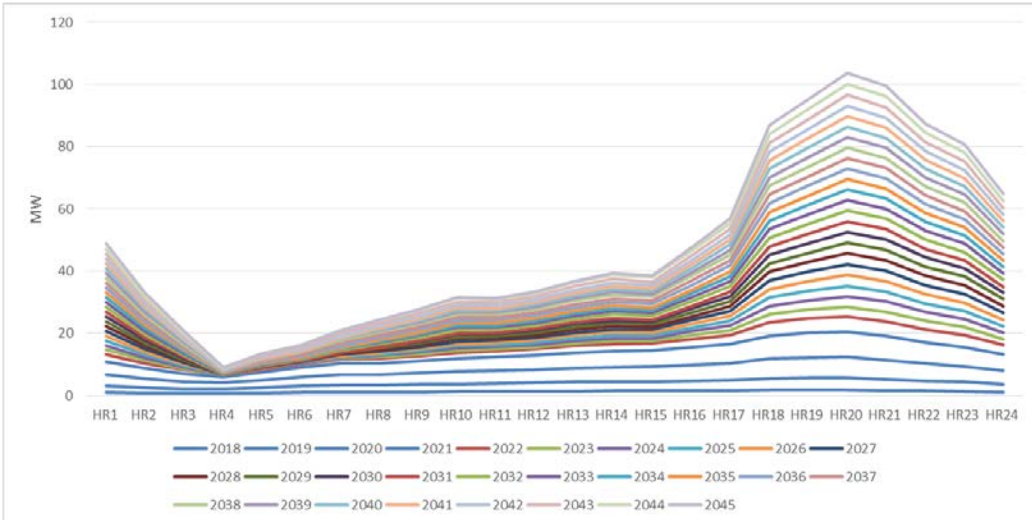


Figure J-34. Example O'ahu Regulating Reserve DR Program Growth over Time

The projected demand profiles (provided by the Companies) are another key input to the DR evaluation. Daily demand dictates the potential for DR programs. For example, air conditioning loads increase on hot days, thereby providing greater potential for air conditioners to participate in a DR program.

AP for Production Simulation also includes system security constraints (provided by the Companies) for DR to improve grid stability specifically for O'ahu. These constraints focus on eliminating under-frequency load shedding (UFLS) after a contingency event such as a unit trip. The constraints include data on net system load, kinetic energy, and the largest contingency. This data enables AP for Production Simulation to determine the amount of Grid Service Fast Frequency Response and segregated customer end-use devices necessary to handle a contingency. Kinetic energy by unit is included in Table J-61. O'ahu's largest contingency unit is, prior to retirement, AES, Kahe 5, then Kahe 6.

Unit	Kinetic Energy (MW-Sec)	Unit	Kinetic Energy (MW-sec)
HPOWER-1	209	Waiau 3	259
HPOWER-2	144	Waiau 4	259
AES	615	Waiau 5	261
Kalaeloa CT-1	591	Waiau 6	256
Kalaeloa ST	287	Waiau 7	426
Kalaeloa CT-2	591	Waiau 8	426
Kahe 1	426	Waiau 9	447
Kahe 2	426	Waiau 10	447
Kahe 3	357	Schofield 1	11
Kahe 4	357	Schofield 2	11
Kahe 5	692	Schofield 3	11
Kahe 6	692	Schofield 4	11
CIP1	765	Schofield 5	11
Honolulu 8	124	Schofield 6	11
Honolulu 9	125	n/a	n/a

Table J-61. Kinetic Energy by Unit for O‘ahu in 2019

Demand Response Portfolio

A portfolio of DR programs is under development. While a preliminary, interim program portfolio application was filed on December 30, 2015, that portfolio is currently being revised, an updated application will be filed February 10, 2017. The information below reflects both the current state of the DR portfolio, pending final refinements prior to the final DR program portfolio application. The sections that follow describe each proposed DR program, the methodology for calculating program costs, the methodology for determining the avoided costs associated with the portfolio (the means of reducing system costs if replaced with DR), and the targeted MWs to be utilized by the Companies.

Demand Response Programs

The DR program portfolio application presented a suite of DR programs that are candidates for the portfolio. Each of the nine DR programs was designed to deliver a specific grid service. The figure below has been updated since the last PSIP filing and interim DR application,[8] to reflect the new grid service naming convention (FFR2 and Replacement Reserves).

[8] See Docket No. 2015-0412, Interim DR Program Portfolio Application filing, filed December 30, 2015.

DR Program	Grid Service Delivered
Real-Time Pricing (RTP)	Capacity
Time-of-Use (TOU)	
Day-Ahead Load Shift (DALS)	
Minimum Load (ML)	
PV Curtailment (PVC)	
Critical Peak Incentive (CPI)	
Fast Frequency Response (FRR)	Fast Frequency Response 1 and 2
Regulating Reserve (RegUp)	Regulating Reserve (RegUp)
Non-Spin Auto Response (NSAR)	Replacement Reserve (RR) (10-Minute)

Table J-62. DR Program to Grid Service Mapping

Descriptions of these programs follow.

Real-Time Pricing. RTP is a capacity grid service resource capable of providing hourly retail rate prices to customers up to six hours before the event day starts. Retail rates will be based on weather, system resource availability, and forecasted load profile. As mentioned earlier, the most operationally and cost-efficient way to deliver Residential RTP programs is with an AMI infrastructure in place.

Time-of-Use. TOU is a capacity grid service resource capable of providing a static period pricing rate for on-peak, off-peak, and mid-day times of the day to residential customers only. Customers are encouraged, through the price differential, to shift their energy usage from the peak time of day to the night or middle of the day, when solar PV is at its peak. Once RTP becomes available, TOU programs are expected to end and the participants will have an opportunity to transition into RTP.

Day-Ahead Load Shift. DALS is a capacity grid service resource capable of providing a static period pricing rate are delivered six hours before the event start day for on-peak, off-peak, and mid-day times of the day to commercial customers only. Customers are encouraged, through the price differential, to shift their energy usage from the peak time of day to the night or middle of the day, when solar PV is at its peak.

Minimum Load. ML is a capacity grid service resource capable of providing increased load in the middle of the day by incentivizing customers to shift their usage to the middle of the day. While identified as an option, this program was not used in any of the portfolios' analysis because the benefits of load shifting programs, such as TOU, DALS, or RTP, were already fulfilling the load flattening benefits.

PV Curtailment. PVC is a capacity grid service resource capable of issuing curtailment of customer's PV during times when minimum must run generators are within a specified threshold limit that requires more load on the system in order to prevent sudden shut down of an online generator. Additionally, PVC is expected to offer circuit-level value in helping to address back-feeding risks as well as power quality and voltage issues. The Demand Response team will collaborate on the development of DER Phase 2 program design to help identify opportunities to incorporate specific PVC options.

Critical Peak Pricing. CPI is a capacity grid service resource capable of providing peak load reduction during emergency situations when not enough generation resources are available. The current existing Commercial DLC program could be re-classified under this program as part of the initial migration.

Fast Frequency Response. FFR program is a FFR grid service resource capable of responding to contingency events within 30 cycles or less.[9] A customer who enrolls in this program would have to be able to offer load resources that could respond to a local discrete response in 30 cycles or less.

Regulating Reserve. RegUp is a grid service resource capable of providing up and down reserves to balance the variability of the system given high renewable penetration. A customer who enrolls in this program must be able to provide a load resource that could initiate a response within two seconds. The Companies examined RegDown as an additional program option, and while there are sufficient resources projected to be capable of delivering such a service, the modeling efforts undertaken did not demonstrate a significant value of this service based on the current resource mix expected to deliver that RegDown service.

Non-Spin Auto Response. NSAR is a 10-minute reserve capable of replacing other resources that are used for Replacement Reserves. Replacement Reserves may be used for restoring regulation or contingency reserves. A customer who is enrolled in this NSAR program would have 10-minutes to respond and reduce their enrolled load resource.

Methodology for Determining Cost of DR Programs

For this PSIP Update, and subsequently for the updated DR program portfolio application, program costs have been developed using a bottom-up approach. This represents a change from the levelized, top-down approach taken during the DR interim application. These costs are embedded into the production cost models when performing optimization of base cases. The Companies will continue to refine cost assumptions in advance of the final DR application; providing the best possible 2-year proposed budget and 15-year avoided cost analysis.

[9] 30 cycles is the maximum FFR response requirement dependent on total MW available. The requirement may be less than 30 cycles after further analysis.

Finally, an inflation rate of 1.8% and annual replacement rate of 5% was used to calculate costs. The following is an excerpt from the Companies response to PSIP IR-40[10] regarding the method of calculating costs:

> In the DR Interim Application, costs were determined using the levelized costs as part of the Potential Study (See Exhibit A of the DR Interim Application). In order to estimate and assess the cost effectiveness of the programs in its current status, a top down approach of levelized cost was used for the DR Interim Application. For the April PSIP Update and final DR Program Portfolio Application filing to be filed in Docket No. 2015-0412 later this year, a bottom-up approach will be used for a more accurate representation of the cost of each of the programs. Key to the bottom-up approach will be estimating the enabling cost of each customer, quantifying their material, incentive, and installation costs. The cost will then be multiplied by the number of customers expected to be enrolled in each program. Followed by additional costs such as labor, marketing, evaluation, and general outside services will then be added to complete the overall cost of the DR program portfolio. The MWs determined through the avoided cost analysis supports the number of customer appliances that are needed on each program. The number of expected customers will be derived and supported from the potential study and the avoided cost analysis update. These updates will be filed as exhibits in the upcoming final DR Program Portfolio Application to be filed in Docket No. 2015-0412 later this year.
>
> Foundationally, historical DR costs incurred by the Companies have been used to calculate the necessary program costs for programs similar to those in the Companies' current portfolio. For program costs associated with proposed programs that are new to the Companies, such as RR[11], responses to the Companies' Grid Services request for proposals, as well as data derived from mainland markets have been used to derive cost estimates."
>
> The key to an accurate program cost projection is the DR Potential Study, which will continue to be updated during the process. While certain costs remain uncertain, such as incentive structures, the Companies have derived incentives from the avoided costs of the programs, less the anticipated administrative and operational costs. The Companies will continue to modify costs over time as programs are implemented and actual costs are tracked.

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[10] Docket 2014-0183; *Companies' Response to Commission Information Requests*, at 7–8.

[11] RR has been renamed "RegUp".

The approach described above has already been undertaken, and the new program costs resulting from that process are as follows:

Island	NPV Cost
O'ahu	$447,357,789
Maui	$60,857,964
Hawai'i Island	$75,679,815
Moloka'i	$817,531
Lana'i	$1,509,259
DRMS	$13,414,991

Table J-63. DR Program Net Present Value Costs

These cost projections are for the E3 cases, but the DR Final Application may include multiple cost projections depending on a variety of resource plans.

Methodology for Determining Avoided Costs of DR Programs

Avoided cost analysis for DR programs allows the Companies to compare the system costs of a base case with DR programs against the system costs of a base case without DR programs.

The following is an excerpt from the Demand Response Interim application:

> Each program will be designed to provide resources that can either directly or in combination with other programs, replace a more costly resource. An iteration analyzing which combination presented the best cost-effective DR programs was performed in the Avoided Cost Analysis. The Avoided Cost analysis resulted in advancing programs that were beneficial for each island in terms of their relative benefit and ultimately their contribution to a cost beneficial portfolio… The cost-effectiveness analysis determined which islands were capable of implementing a cost-effective DR Portfolio, although further analysis is required before finalizing the entire portfolio of programs for each island.[12]

The Companies, in tandem with Black & Veatch modelers, have developed specific modeling techniques to evaluate the range of services provided by DR based on the characteristics of each service combined with the performance characteristics of the individual end uses. The methodology for calculating the avoided cost, as well as the specific modeling techniques is described in Appendix H, under the Adaptive Planning for Production Simulation description.

The avoided cost for a grid service is the cost of an alternative resource (energy storage or a generator) to provide the equivalent service. Avoided costs are based on several factors,

[12] Section IX of Docket 2015-0412 filed December 30, 2015

including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Additionally, alterations to a base case capital plan promote meaningful avoided costs opportunities. In the context of the PSIP Update, the following represent examples of potential avoided cost values of DR across the different systems:

O'ahu: The DR portfolio enables reduction in size of the Contingency battery, improved heat rate performance and reduced fuel costs.

Maui: The DR portfolio enables improved heat rate performance and reduced fuel costs.

Moloka'i: The DR portfolio enables improved heat rate performance and reduced fuel costs.

Lana'i: The DR portfolio enables improved heat rate performance and reduced fuel costs.

Hawai'i Island: The DR portfolio enables improved heat rate performance and reduced fuel costs.

During the PSIP modeling process, multiple base cases were created, generating multiple DR portfolios. The DR portfolios include varying amounts of end device potentials, including customer storage, by year and island. Customer storage uptake forecasting is synergistic with DR portfolio optimization, and the resource is considered as a DR end use capable of providing multiple grid services.

The DR portfolio development started with no DR resource base cases, then created the DR portfolio from each base case, but did not add that new portfolio into the base case, unless that base case would proceed towards a cost beneficial plan. Optimization of the DR portfolio will be performed in the next iteration. The final cost, avoided cost and cost effectiveness analysis will utilize the optimized DR portfolio and include it within the Final DR Application, anticipated for filing February 10, 2017.

DR Grid Service Portfolio: O'ahu

Customer	Commercial		
Program	*Regulating Reserves*	*Fast Frequency Response*	*Pricing*
Grid Service	RegUp	FFR	Capacity
Frequency	Continuous	Contingency Event	Daily
Event Length	30 minutes	10 minutes	24 hours
Year	MW	MW	MW
2016	–	–	–
2017	–	–	–
2018	0.45	18.40	-
2019	1.44	19.11	-
2020	3.10	17.27	27.18
2021	6.82	18.98	29.86
2022	9.92	21.25	32.42
2023	12.78	23.61	35.00
2024	15.82	26.21	37.85
2025	18.98	29.11	41.13
2026	22.27	32.11	44.83
2027	25.66	35.23	48.56
2028	29.21	38.86	52.50
2029	32.80	42.28	56.61
2030	36.52	45.88	61.12
2031	40.32	49.50	66.85
2032	44.21	52.87	72.44
2033	48.09	56.61	78.18
2034	52.11	60.35	83.43
2035	56.13	64.18	88.66
2036	60.18	68.67	94.12
2037	64.23	72.73	90.13
2038	68.33	76.83	94.82
2039	72.50	80.94	99.57
2040	76.78	85.08	104.16
2041	80.97	89.27	108.79
2042	85.21	93.48	113.34
2043	89.48	97.75	118.08
2044	93.74	102.05	122.88
2045	98.10	106.31	127.60

Table J-64. O'ahu DR Program Grid Service Portfolio (1 of 2)

DR Grid Service Portfolio: O'ahu (2 of 2)

Customer	Residential			Small Business		
Program	*Regulating Reserves*	*Fast Frequency Response*	*Pricing*	*Regulating Reserves*	*Fast Frequency Response*	*Pricing*
Grid Service	RegUp	FFR	Capacity	RegUp	FFR	Capacity
Frequency	Continuous	Contingency Event	Daily	Continuous	Contingency Event	Daily
Event Length	30 minutes	10 minutes	24 hours	30 minutes	10 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–
2017	–	0.77	0.77	–	0.04	–
2018	4.74	20.35	3.96	0.38	1.39	0.09
2019	12.02	35.71	8.58	1.12	2.55	0.14
2020	20.77	43.95	41.69	2.11	3.61	10.65
2021	28.51	48.37	47.50	3.09	4.00	11.38
2022	32.88	51.73	53.76	3.88	4.56	12.13
2023	36.21	48.50	60.60	4.19	3.97	12.62
2024	39.76	54.01	67.31	4.53	4.38	13.30
2025	44.05	57.72	74.80	4.89	4.77	14.29
2026	51.12	67.94	84.47	5.27	5.21	15.21
2027	58.39	77.61	93.97	5.66	5.68	16.44
2028	65.89	83.18	103.37	6.08	6.35	17.88
2029	73.43	92.91	106.34	6.51	7.00	19.34
2030	81.23	100.85	114.20	6.96	7.68	21.30
2031	89.46	108.98	122.41	7.44	8.36	23.87
2032	97.84	117.30	130.80	7.95	9.22	26.31
2033	106.40	125.78	139.16	8.44	10.82	29.24
2034	115.14	134.44	147.43	8.91	12.32	32.22
2035	124.00	141.70	155.56	9.43	13.81	35.41
2036	133.07	152.24	163.76	9.96	14.85	38.38
2037	142.15	161.37	171.97	10.52	14.10	31.21
2038	151.40	170.66	180.41	11.07	15.15	32.69
2039	160.98	179.76	189.03	11.63	16.22	34.19
2040	170.69	189.68	197.78	12.18	18.23	35.44
2041	180.38	199.40	206.69	12.77	19.75	36.81
2042	190.32	209.27	215.69	13.38	21.20	38.22
2043	200.30	219.29	224.96	14.03	22.78	39.34
2044	210.43	229.44	234.40	14.68	23.85	40.52
2045	220.94	239.74	244.09	15.27	24.96	41.68

Table J-65. O'ahu DR Program Grid Service Portfolio (2 of 2)

DR Grid Service Portfolio: Maui

Customer	Commercial		Small Business	
Program	*Regulating Reserves*	*Pricing*	*Regulating Reserves*	*Pricing*
Grid Service	RegUp	Capacity	RegUp	Capacity
Frequency	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW
2016	–	–	–	–
2017	–	–	–	–
2018	–	0.59	–	1.11
2019	–	1.15	–	1.87
2020	0.01	2.52	0.28	2.58
2021	0.03	2.50	0.35	2.73
2022	0.07	2.51	0.47	2.86
2023	0.11	2.67	0.60	2.93
2024	0.15	2.79	0.69	3.06
2025	0.19	3.11	0.78	3.19
2026	0.23	3.22	0.92	3.35
2027	0.28	3.22	0.99	3.59
2028	0.33	3.29	1.04	3.86
2029	0.38	3.36	1.14	4.08
2030	0.43	3.42	1.20	4.33
2031	0.48	3.49	1.31	4.57
2032	0.53	3.59	1.45	4.81
2033	0.58	3.73	1.57	5.11
2034	0.64	3.86	1.71	5.41
2035	0.69	3.97	1.86	5.69
2036	0.75	4.09	2.00	5.98
2037	0.80	3.74	2.14	5.39
2038	0.86	3.82	2.30	5.62
2039	0.91	3.91	2.50	5.83
2040	0.97	3.98	2.64	6.05
2041	1.02	4.07	2.78	6.27
2042	1.08	4.14	2.94	6.49
2043	1.14	4.22	3.14	6.74
2044	1.19	4.29	3.32	6.97
2045	1.25	4.37	3.49	7.18

Table J-66. Maui DR Program Grid Service Portfolio (1 of 2)

DR Grid Service Portfolio: Maui (2 of 2)

Customer	Residential				
Program	*Regulating Reserves*	*Fast Frequency Response*	*Pricing*	NSAR	CPI
Grid Service	RegUp	FFR	Capacity	Replacement Reserves	Capacity
Frequency	Continuous	Contingency Event	Daily	Contingency	Emergency
Event Length	30 minutes	10 minutes	24 hours	1 hour	4 hours
Year	MW	MW	MW	MW	MW
2016	–	–	–	–	–
2017	–	0.24	0.97	0.24	0.24
2018	0.60	0.60	2.84	0.60	0.60
2019	1.30	1.30	5.09	1.30	1.30
2020	2.10	2.10	8.72	2.10	2.10
2021	2.89	2.57	9.50	2.57	2.57
2022	3.52	2.88	10.34	2.88	2.88
2023	4.58	3.67	11.64	3.67	3.67
2024	6.34	5.01	13.22	5.01	5.01
2025	7.63	6.41	15.01	6.41	6.41
2026	9.09	7.86	16.87	7.86	7.86
2027	10.50	9.37	18.87	9.37	9.37
2028	11.90	10.92	20.86	10.92	10.92
2029	13.29	12.51	21.72	12.51	12.51
2030	15.22	14.15	23.55	14.15	14.15
2031	16.62	15.84	25.47	15.84	15.84
2032	18.64	17.57	27.45	17.57	17.57
2033	20.32	19.34	29.57	19.34	19.34
2034	21.86	21.15	31.77	21.15	21.15
2035	23.97	23.01	33.87	23.01	23.01
2036	25.96	24.90	36.08	24.90	24.90
2037	27.49	26.83	38.38	26.83	26.83
2038	30.06	28.80	40.64	28.80	28.80
2039	32.10	30.81	42.96	30.81	30.81
2040	34.12	32.85	45.23	32.85	32.85
2041	36.15	34.94	47.60	34.94	34.94
2042	37.80	37.06	50.03	37.06	37.06
2043	40.16	39.23	52.35	39.23	39.23
2044	42.15	41.43	54.83	41.43	41.43
2045	44.55	43.67	57.35	43.67	43.67

Table J-67. Maui DR Program Grid Service Portfolio (2 of 2)

DR Grid Service Portfolio: Lana‘i

Customer	Commercial		Residential		Small Business	
Program	*Regulating Reserves*	*Pricing*	*Regulating Reserves*	*Pricing*	*Regulating Reserves*	*Pricing*
Grid Service	RegUp	Capacity	RegUp	Capacity	RegUp	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–
2017	–	–	–	0.02	–	–
2018	0.00	0.02	0.00	0.05	0.00	0.02
2019	0.00	0.03	0.01	0.09	0.00	0.04
2020	0.01	0.05	0.03	0.11	0.01	0.05
2021	0.01	0.06	0.04	0.15	0.01	0.06
2022	0.01	0.07	0.04	0.18	0.01	0.07
2023	0.01	0.08	0.04	0.20	0.01	0.07
2024	0.01	0.08	0.04	0.21	0.01	0.07
2025	0.01	0.09	0.04	0.22	0.01	0.07
2026	0.01	0.09	0.04	0.23	0.01	0.08
2027	0.01	0.09	0.04	0.25	0.01	0.08
2028	0.01	0.09	0.05	0.27	0.01	0.09
2029	0.01	0.10	0.04	0.28	0.01	0.10
2030	0.01	0.10	0.04	0.26	0.01	0.10
2031	0.01	0.10	0.05	0.27	0.01	0.11
2032	0.01	0.10	0.03	0.29	0.01	0.11
2033	0.01	0.10	0.04	0.29	0.01	0.11
2034	0.01	0.11	0.04	0.30	0.01	0.12
2035	0.01	0.11	0.05	0.31	0.01	0.13
2036	0.01	0.11	0.04	0.32	0.01	0.13
2037	0.01	0.11	0.04	0.32	0.01	0.13
2038	0.01	0.10	0.04	0.32	0.01	0.10
2039	0.01	0.10	0.04	0.33	0.01	0.10
2040	0.01	0.10	0.05	0.34	0.01	0.11
2041	0.01	0.10	0.04	0.34	0.01	0.11
2042	0.01	0.10	0.05	0.35	0.01	0.11
2043	0.01	0.10	0.05	0.35	0.01	0.11
2044	0.01	0.10	0.04	0.36	0.01	0.11
2045	0.02	0.10	0.05	0.36	0.01	0.11

Table J-68. Lana‘i DR Program Grid Service Portfolio

DR Grid Service Portfolio: Molokaʻi

Customer	Commercial		Residential		Small Business	
Program	*Regulating Reserves*	*Pricing*	*Regulating Reserves*	*Pricing*	*Regulating Reserves*	*Pricing*
Grid Service	RegUp	Capacity	RegUp	Capacity	RegUp	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–
2017	–	–	–	0.02	–	–
2018	0.00	0.01	0.00	0.07	0.00	0.03
2019	0.00	0.02	0.01	0.12	0.01	0.06
2020	0.00	0.04	0.04	0.14	0.01	0.05
2021	0.01	0.05	0.06	0.18	0.02	0.06
2022	0.01	0.05	0.05	0.22	0.02	0.08
2023	0.01	0.05	0.04	0.23	0.02	0.08
2024	0.01	0.05	0.04	0.24	0.02	0.08
2025	0.01	0.06	0.05	0.24	0.02	0.08
2026	0.01	0.06	0.05	0.25	0.02	0.07
2027	0.01	0.06	0.05	0.27	0.02	0.08
2028	0.01	0.06	0.05	0.27	0.02	0.08
2029	0.01	0.06	0.05	0.28	0.02	0.09
2030	0.01	0.07	0.05	0.26	0.02	0.09
2031	0.01	0.07	0.05	0.27	0.02	0.10
2032	0.01	0.07	0.05	0.28	0.02	0.10
2033	0.01	0.07	0.05	0.28	0.02	0.10
2034	0.01	0.07	0.05	0.28	0.02	0.10
2035	0.01	0.07	0.05	0.28	0.02	0.10
2036	0.01	0.07	0.06	0.28	0.02	0.10
2037	0.01	0.07	0.05	0.28	0.02	0.10
2038	0.01	0.06	0.05	0.29	0.02	0.09
2039	0.01	0.06	0.06	0.29	0.02	0.09
2040	0.01	0.06	0.06	0.29	0.02	0.09
2041	0.01	0.06	0.06	0.29	0.02	0.09
2042	0.01	0.06	0.06	0.29	0.02	0.09
2043	0.01	0.06	0.05	0.29	0.02	0.08
2044	0.01	0.06	0.06	0.29	0.02	0.09
2045	0.01	0.06	0.06	0.28	0.02	0.09

Table J-69. Molokaʻi DR Program Grid Service Portfolio

DR Grid Service Portfolio: Hawai‘i Island

Customer	Commercial		Residential		Small Business	
Program	*Regulating Reserves*	*Pricing*	*Regulating Reserves*	*Pricing*	*Regulating Reserves*	*Pricing*
Grid Service	RegUp	Capacity	RegUp	Capacity	RegUp	Capacity
Frequency	Continuous	Daily	Continuous	Daily	Continuous	Daily
Event Length	30 minutes	24 hours	30 minutes	24 hours	30 minutes	24 hours
Year	MW	MW	MW	MW	MW	MW
2016	–	–	–	–	–	–
2017	–	–	–	1.01	–	–
2018	0.46	0.46	0.69	2.77	0.09	1.02
2019	0.77	0.77	1.46	4.72	0.21	1.70
2020	1.15	1.15	2.43	5.84	0.40	1.66
2021	1.39	1.39	3.35	7.22	0.54	2.02
2022	1.61	1.61	4.39	8.99	0.82	2.56
2023	1.61	1.61	5.87	10.51	1.03	2.76
2024	1.60	1.60	7.63	12.14	1.22	2.96
2025	1.58	1.58	9.24	13.83	1.45	3.18
2026	1.56	1.56	11.01	15.64	1.67	3.43
2027	1.53	1.53	12.71	17.42	1.98	3.69
2028	1.49	1.49	14.70	19.24	2.19	3.93
2029	1.45	1.45	16.58	21.05	2.49	4.17
2030	1.43	1.43	18.74	22.89	2.73	4.43
2031	1.43	1.43	20.69	24.97	3.04	4.74
2032	1.41	1.41	22.75	27.15	3.41	5.05
2033	1.41	1.41	25.15	29.37	3.62	5.37
2034	1.44	1.44	27.52	31.66	3.93	5.70
2035	1.45	1.45	29.75	34.08	4.29	6.05
2036	1.48	1.48	32.01	36.58	4.67	6.40
2037	1.48	1.48	34.60	39.20	5.05	6.80
2038	1.50	1.50	37.06	41.84	5.40	7.19
2039	1.51	1.51	39.85	44.56	5.77	7.58
2040	1.55	1.55	42.20	47.26	6.24	7.98
2041	1.57	1.57	45.30	50.08	6.55	8.39
2042	1.59	1.59	48.12	52.95	6.97	8.79
2043	1.60	1.60	51.02	55.94	7.37	9.24
2044	1.60	1.60	53.75	58.93	7.82	9.70
2045	1.65	1.65	56.76	61.96	8.25	10.14

Table J-70. Hawai‘i Island DR Program Grid Service Portfolio

K. Analytical Steps and Results

O'AHU ANALYTICAL STEPS AND RESULTS

The core cases analyzed for O'ahu outline different paths to achieving 100% renewable energy in 2045.

Energy Mix of O'ahu Plans

Figure K-1 summarizes the annual RPS for each year.

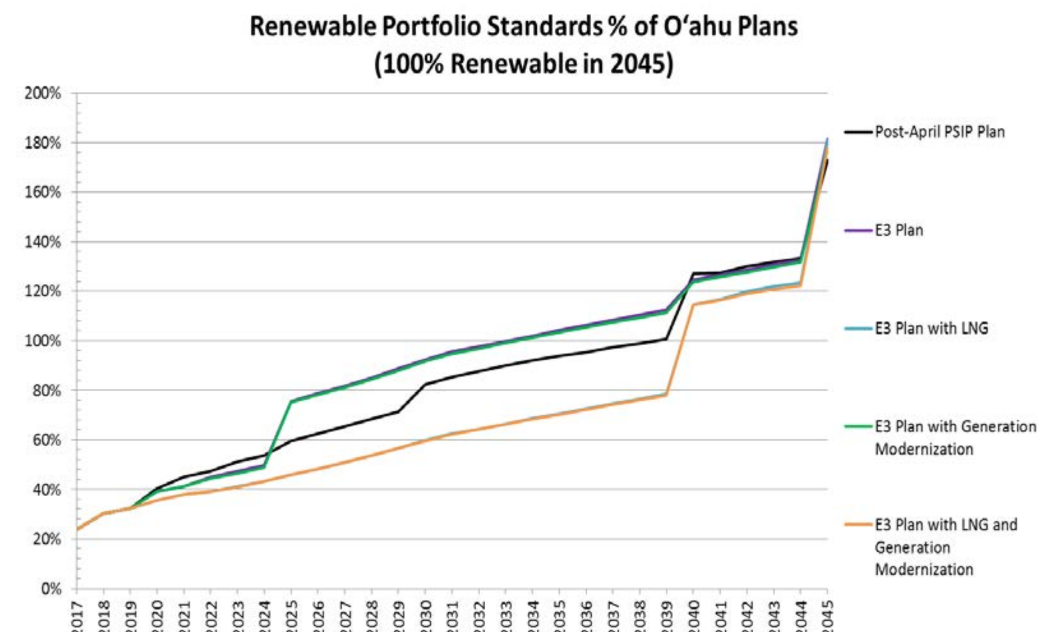

Figure K-1. Renewable Portfolio Standards Percent of O'ahu Plans

The calculation of the RPS per the law does result in values over 100%. To emphasize that we are committed to achieving 100% renewable energy in 2045, Figure K-2 shows the renewable energy as a percent of total energy including customer-sited generation.

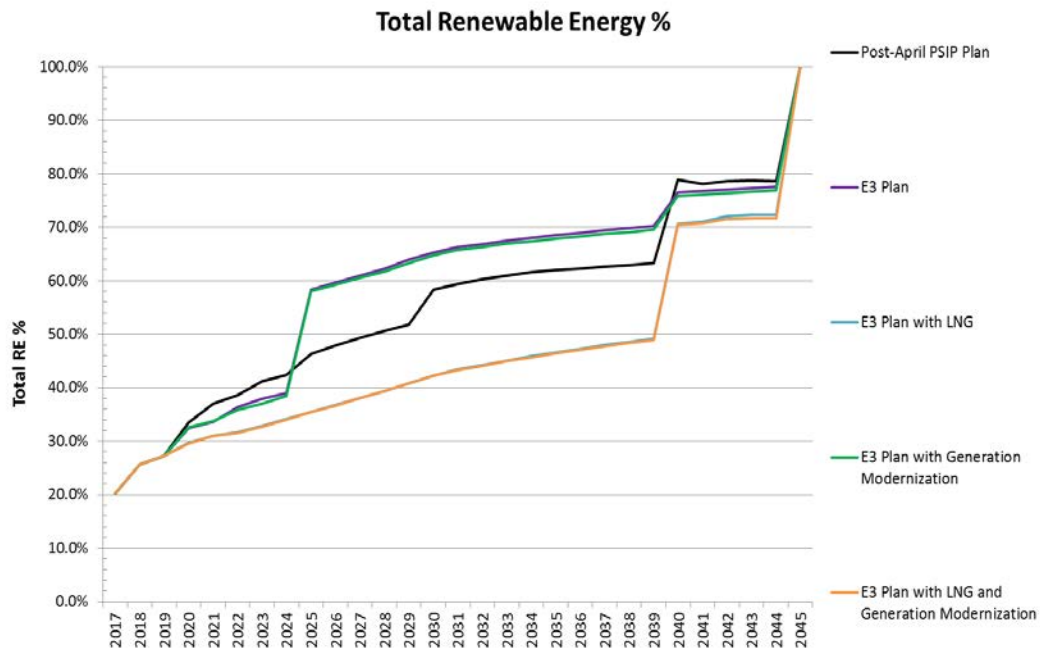

Figure K-2. Total Renewable Energy Percent of O'ahu Plans

The resource mix for the plans changes over time as it reaches 100% renewable in 2045. The figures below reveal how the energy mix in each plan grows to 100% renewable energy.

The annual energy served by resource type is shown in Figure K-3 for the Post-April PSIP Plan. The transition to renewable wind and solar can be easily seen as the fossil fuel (oil and coal) significantly decreases over time.

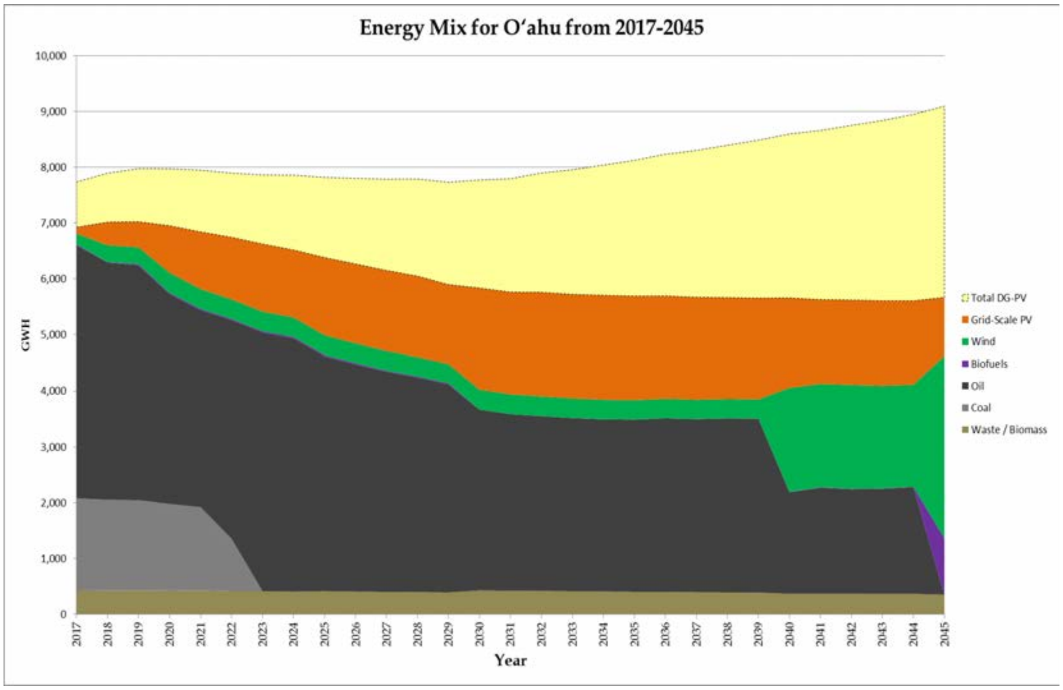

Figure K-3. Energy Mix for Post-April PSIP Plan on O'ahu

Figure K-4 shows the energy mix of the E3 Plan without LNG.

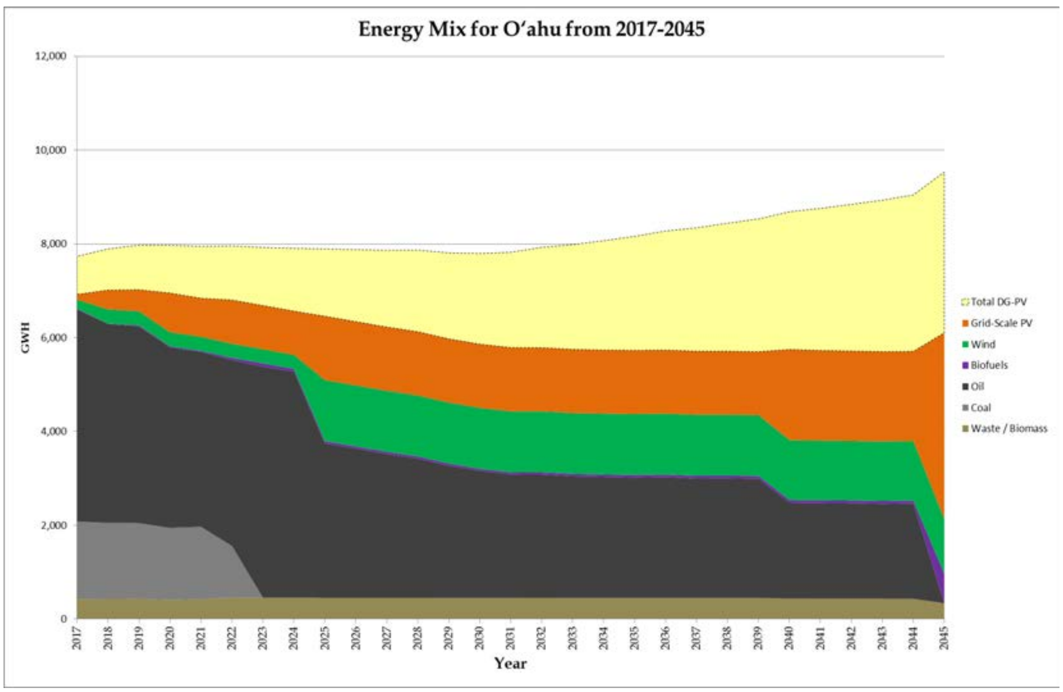

Figure K-4. Energy Mix for E3 Plan on O'ahu

The E3 Plan with LNG uses LNG as a transitional fuel from oil. Renewable energy is added economically to meet intermediate RPS targets and ultimately 100% renewable energy in 2045. The energy mix for E3 Plan with LNG is shown in Figure K-5. The

transition to LNG assumes a contract period of 2022–2041. During the last intervening years in the transition to 100% renewable energy, potential future resources at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

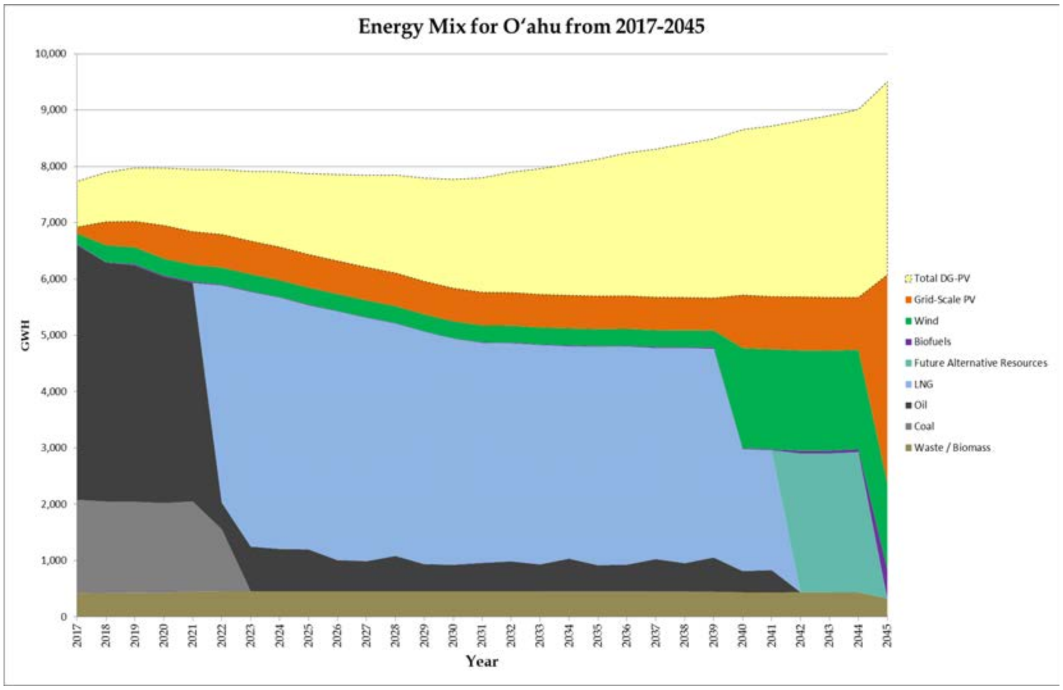

Figure K-5. Energy Mix for E3 Plan with LNG on O'ahu

Including generation modernization did not noticeably change the E3 Plan without LNG as shown in Figure K-6.

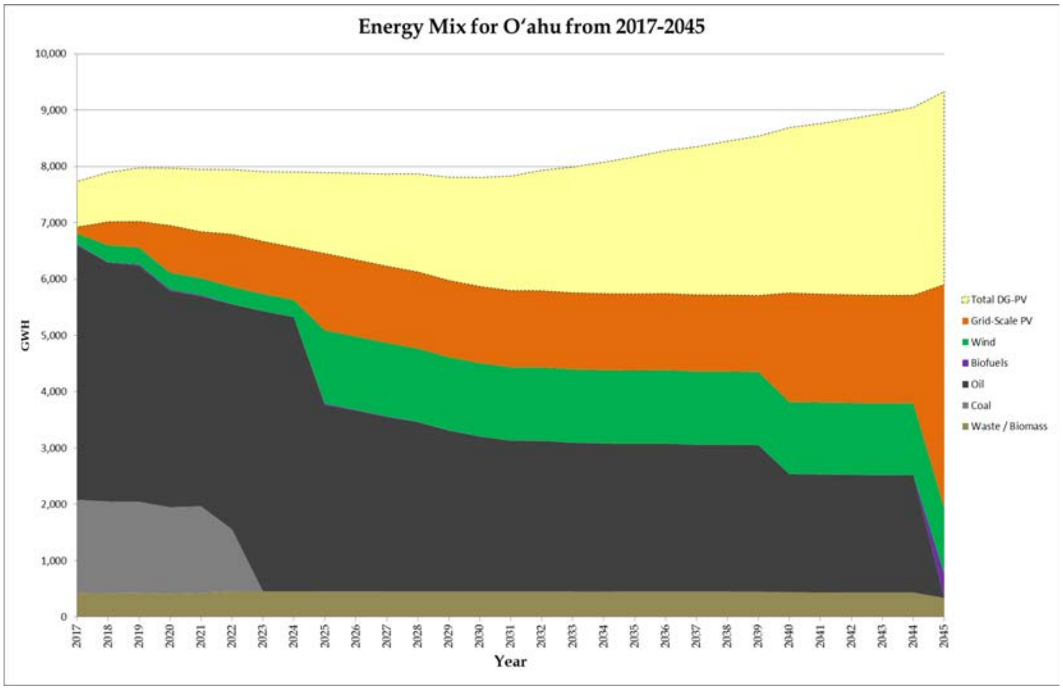

Figure K-6. Energy Mix for E3 Plan with Generation Modernization on O'ahu

Similarly, including generation modernization did not noticeably change the E3 Plan with LNG as shown in Figure K-7 below. Again, the transition to LNG assumes a contract period of 2022–2041. During the last intervening years in the transition to 100% renewable energy, potential future resources at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

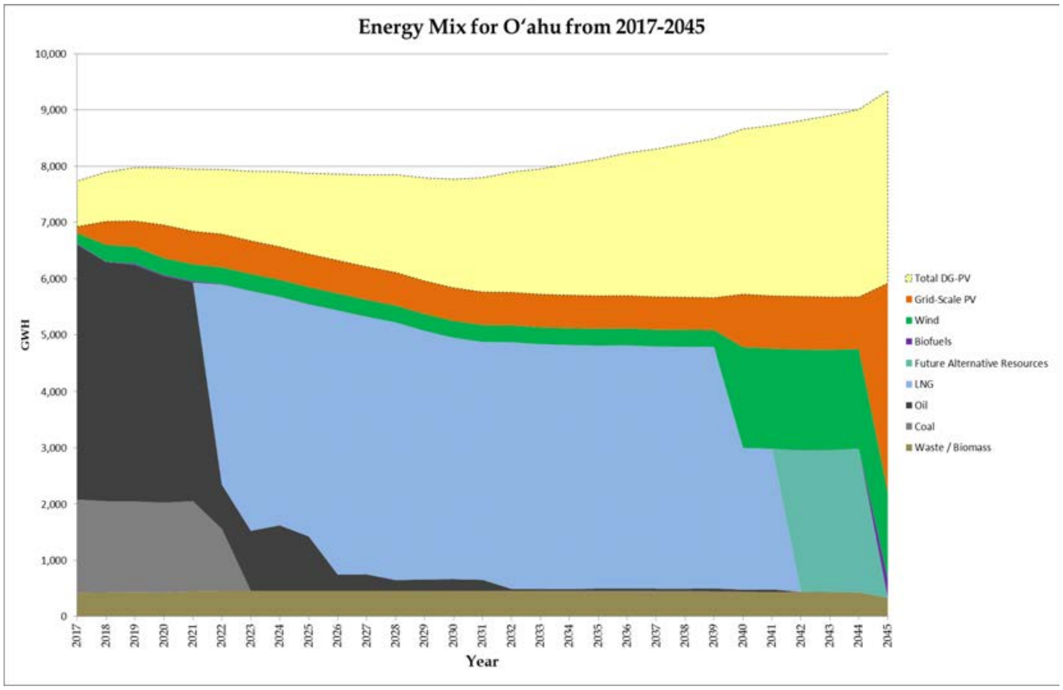

Figure K-7. Energy Mix for E3 Plan with LNG and Generation Modernization

Percent Over-Generation of Total System for O'ahu Plans

Hawaiian Electric has been actively increasing the flexibility of the existing generating units to integrate increasing levels of variable generation. All the core cases analyzed include the capability to operate existing generating units at lower minimum load levels, minimizing baseload operation of the existing generators, and adding new firm flexible generation along with increasing wind and solar generation. Even with more flexible firm generating units, there may still be instances of over-generation of variable resources during low demand periods (which may occur during daytime hours due to influence of DG-PV, as well as during typical night time low load hours).

As increasingly more renewable energy is added to the system, over-generation occurrences will become inevitable. Figure K-8 provides estimates of the percent over-generation of the total system annual energy for the various plans. Since the Post-April PSIP Plan integrates greater amounts of grid-scale PV than the E3 plans in the earlier years, the percent over-generation is higher in these years in the Post-April PSIP Plan. The E3 plans add greater amounts of storage much earlier than the Post-April PSIP Plan which helps to reduce over-generation. Situations of over-generation, however, provide opportunities to allow wind and solar generation to contribute to regulation up resources in addition to use as a reserve resource, if they are coupled with appropriate control systems. This provides improved system performance . In combination, wind and solar used for energy and some level of regulation and reserve appears to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this December 2016 PSIP update (similar to the April 2016 PSIP update), we include the full cost of the grid-scale wind and grid-scale PV resources in cost calculations, regardless of over-generation levels and provide a simplified accounting for other services from these resources.

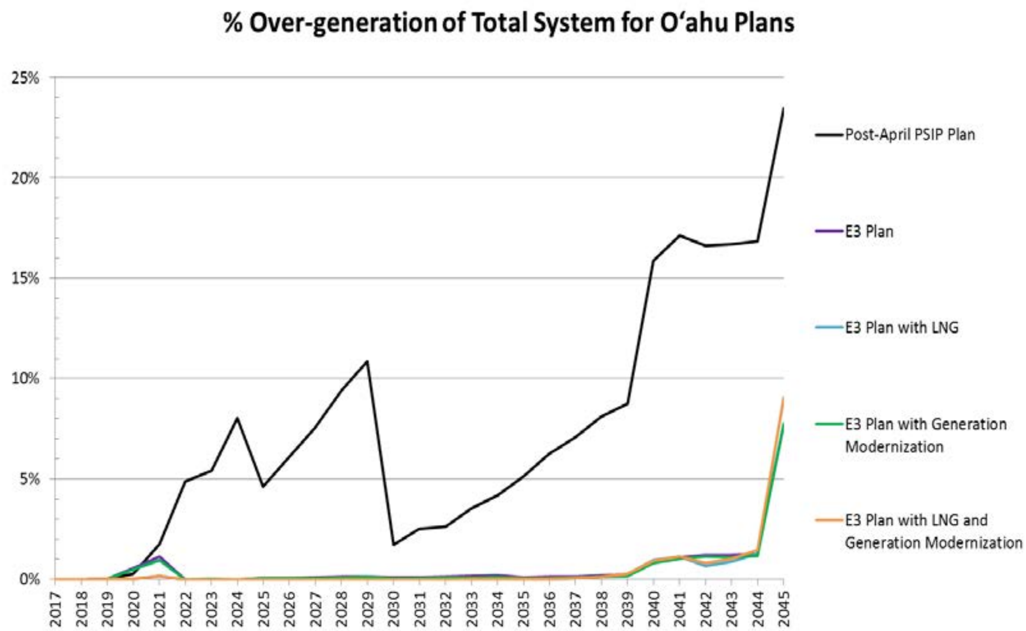

Figure K-8. Total System Over-Generation Percent for O'ahu Plans

Unserved Energy of O'ahu Plans

While periods of over-supply exist as described above, periods of unserved energy can also occur. The plans evaluate whether sufficient generation to serve load exists with variable renewable energy and storage with minimal conventional thermal resources on the system. The E3 plans identified existing conventional thermal generating units that could be considered for removal from service as an economic option. For the PLEXOS modeling of the E3 plans, these units were made unavailable to serve load or "offline". If there was sufficient generation provided by the remaining thermal resources, variable renewable resources, and storage, then there would not be any unserved energy. The year-by-year amount of unserved energy in hours and energy for the E3 Plan is shown in Figure K-9. There are some years that have significant amounts of unserved energy. For example, in 2022, there are approximately 2,000 MWh total of unserved energy that occurs over the course of 36 hours in that year.

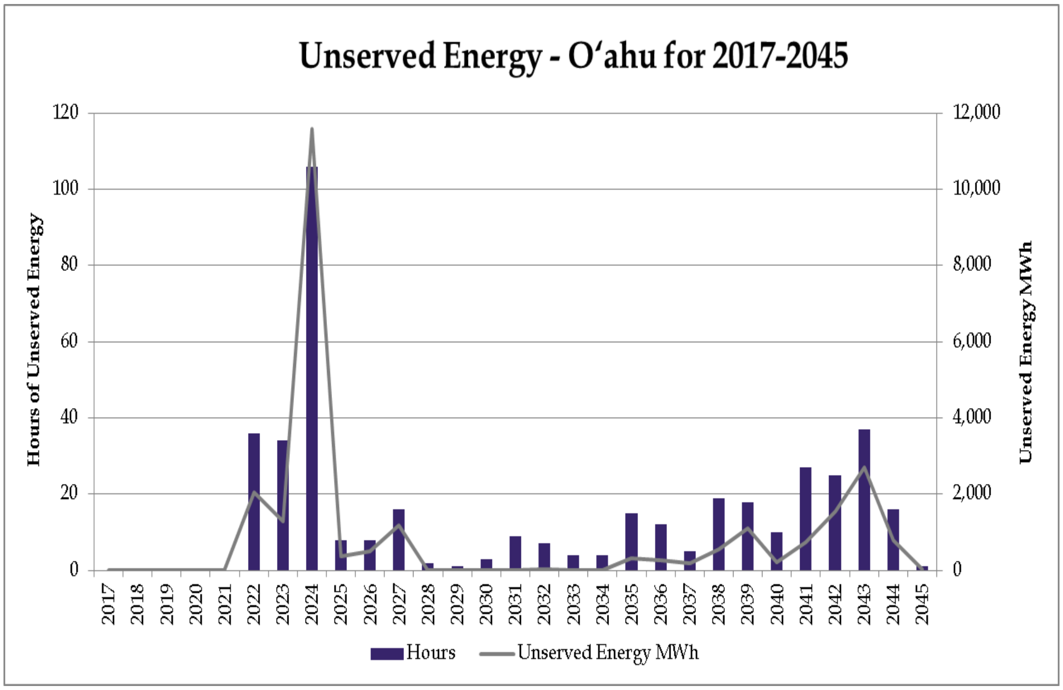

Figure K-9. Unserved Energy for E3 Plan on O'ahu

As shown in Figure K-10, the E3 Plan with Generation Modernization significantly reduces the amount of unserved energy. For example, in 2022, there is about 0.56 MWh of unserved energy which occurs over about 6 hours in the year.

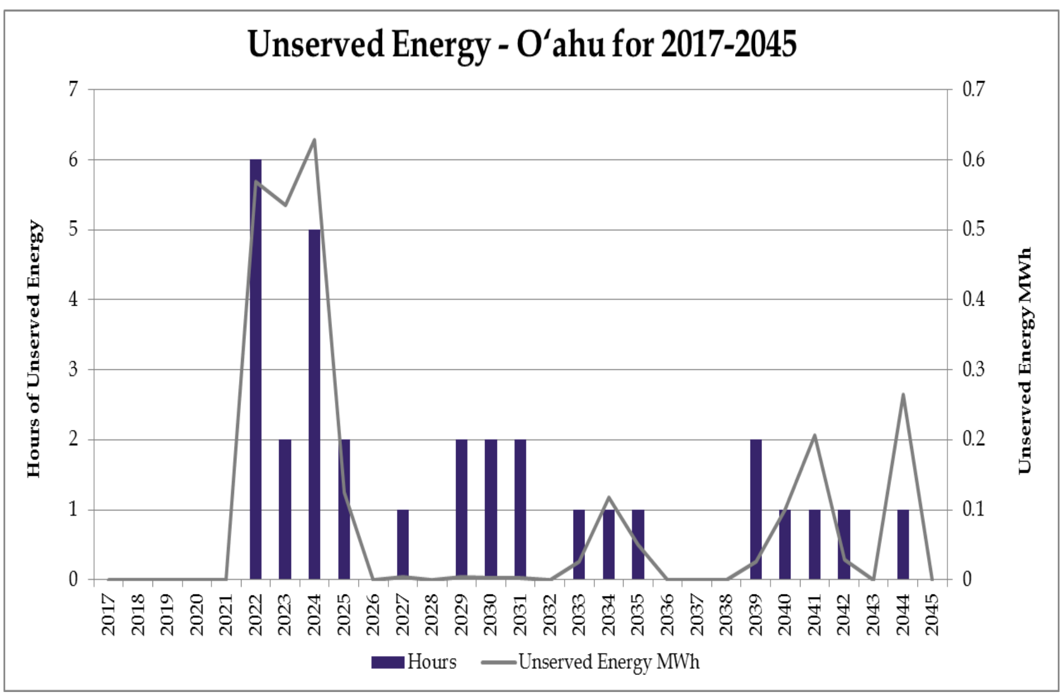

Figure K-10. Unserved Energy for E3 Plan with Generation Modernization on O'ahu

The Post-April PSIP Plan gradually incorporates generation modernization with the deactivation of existing thermal resources. Figure K-11 indicates that the Post-April PSIP Plan does not have unserved energy until about 2030 and does not have more than 5 hours of unserved energy in any given year through 2045. The few hours of unserved energy could be investigated in more detail and may be due to thermal generating units being on maintenance which could be adjusted or refined as we approach the year of concern.

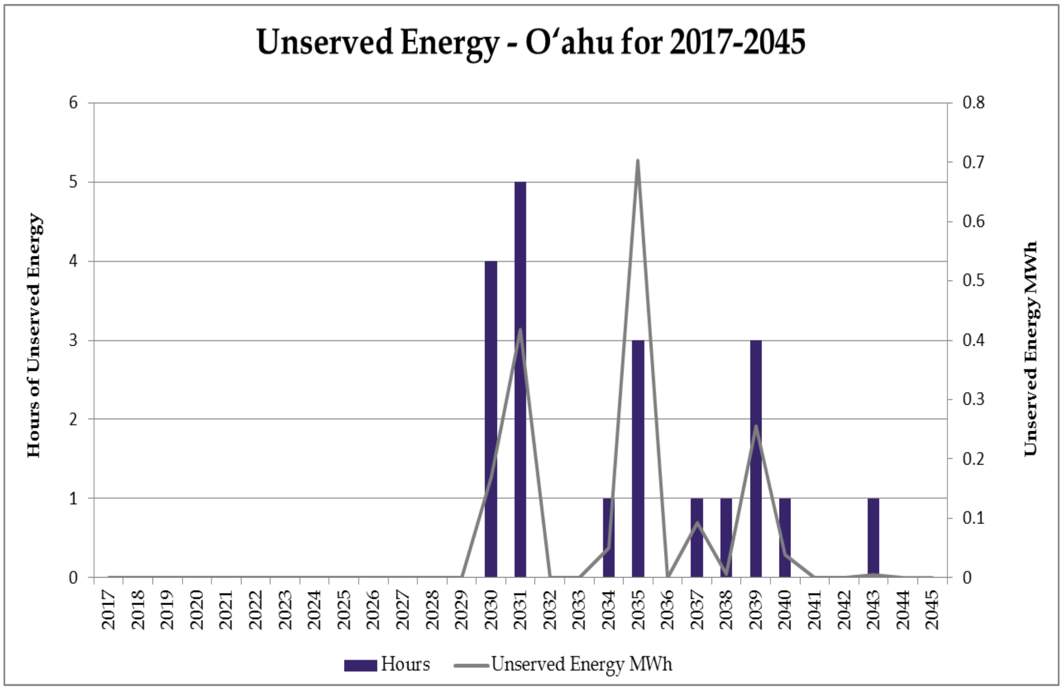

Figure K-11. Unserved Energy for Post-April PSIP Plan on O'ahu

Seasonal Variations of O'ahu Renewable Energy

With limited firm renewable resources available on-island on O'ahu, the majority of renewable energy will be supplied from either variable, intermittent generation or biofueled thermal generation. The figures below illustrate the impact of seasonal variations in variable renewable generation such as wind and solar.

Figure K-12 shows the difference between the load and the available renewable energy in the year 2025 for the E3 Plan. To prevent unserved energy, this difference must be served with thermal generation.

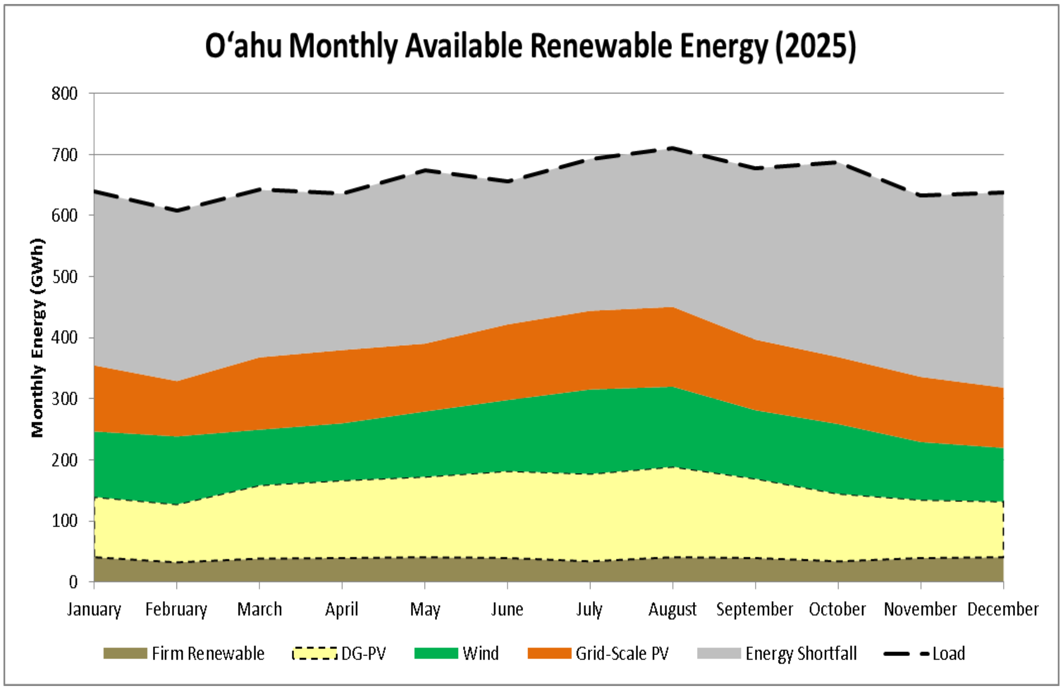

Figure K-12. E3 Plan Monthly Available Renewable Energy vs Load on O'ahu in 2025

Figure K-13 shows the difference between the load and the available renewable energy in the year 2045 for the E3 Plan. In 2045, in the E3 Plan, there is approximately 2,100 MW of DG-PV, over 2,000 MW of grid-scale PV, 200 MW of offshore wind, 68 MW of waste to energy, and 160 MW of onshore wind. Despite these high amounts of renewables on the system, there are some months where there is a deficit of renewable energy available, shown in gray, to serve the load.. However, there are also months for which there is a surplus, shown in pink. This highlights the continued need for thermal generators to provide supplemental generation during these shortfall periods or energy storage systems, which are capable of shifting energy over several months from the months where there is a surplus to the months where there are shortfalls.

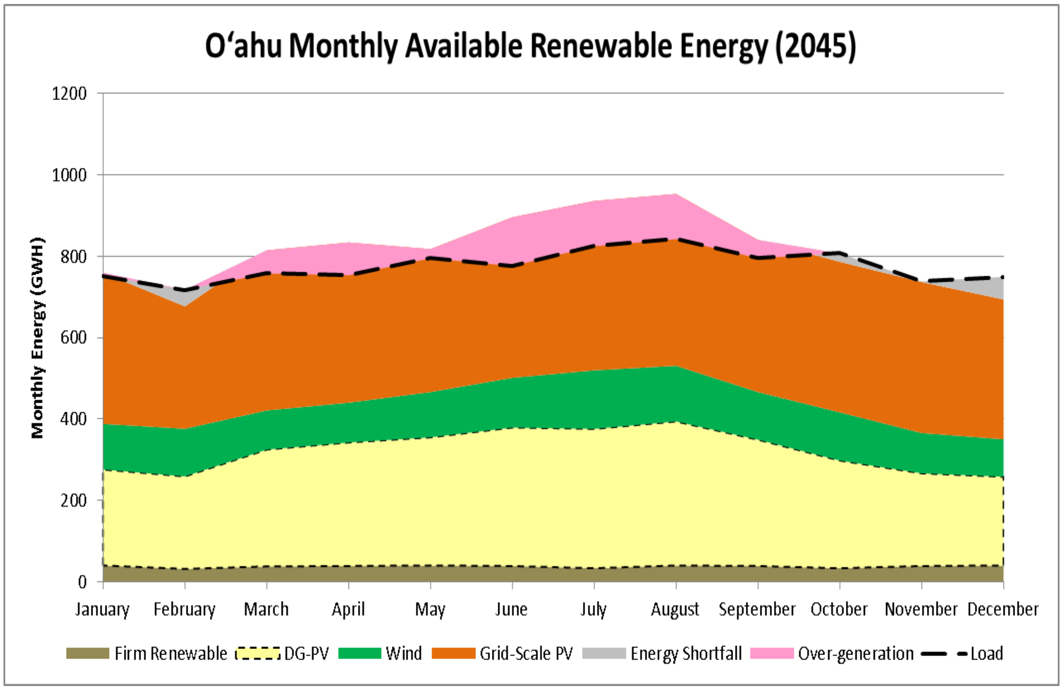

Figure K-13. E3 Plan Monthly Available Renewable Energy vs Load on O'ahu in 2045

Sub-Hourly Charts of O'ahu Plans

Sub-hourly modeling was performed to analyze the impact that variable renewable energy would have on our system, and whether our portfolio of generators and storage systems would be sufficient to stabilize the electrical grid.

Historical minutely renewable energy data was used to determine the volatility of solar and wind resources on O'ahu. The volatility of the Kahuku wind farm was applied to future grid-scale wind resources, and the volatility of the Kalaeloa Renewable Energy Park (KREP) PV project was applied to future grid-scale PV resources.

An initial screening was done to determine the month with the largest potential minutely downward ramp. PLEXOS was then employed to perform a stochastic analysis on this month. Using the historical minutely data, stochastic variables were created for all as-available resources and the load. Shown below are the results from the sub-hourly analysis of the E3 Plan when a 1-, 15-, and 30-minute look-ahead is assumed.

Figure K-14 shows the estimated unserved energy at a 1 minute look-ahead for the E3 plan.

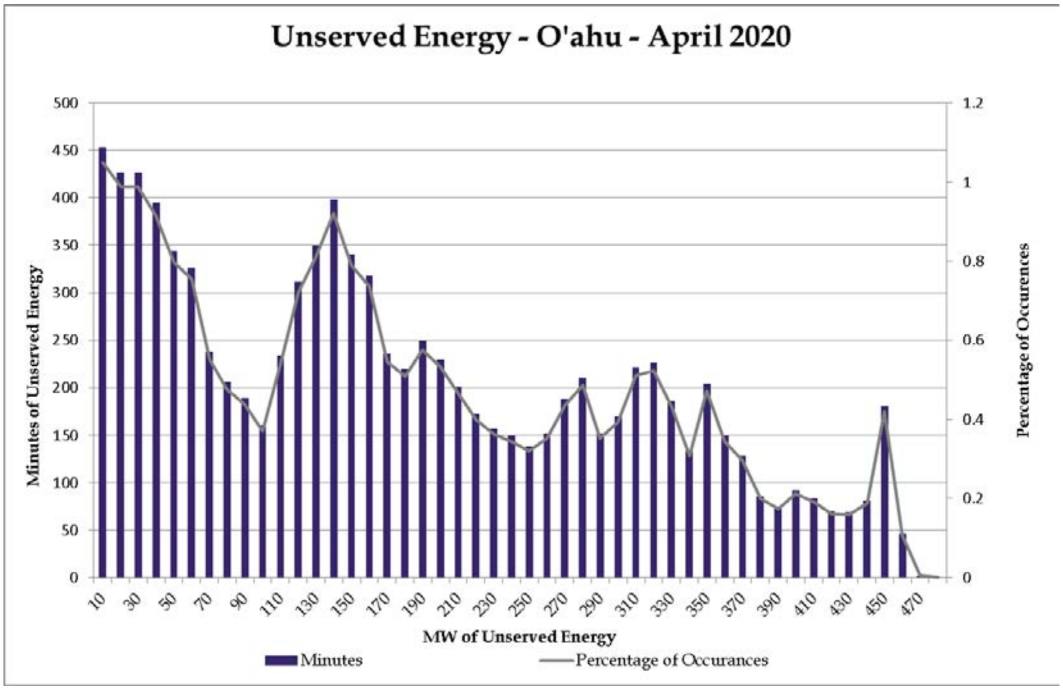

Figure K-14. Sub-Hourly Unserved Energy for E3 Plan on O‘ahu at 1-Minute Look-Ahead

Figure K-15 shows the estimated unserved energy at a 1-minute look-ahead for the Post-April PSIP plan. Comparing Figure K-14 from the E3 Plan which does not include a regulating battery to Figure K-15, from the Post-April PSIP Plan, which includes a 100 MW regulating battery in 2020, both the number of occurrences as well as the magnitude of the event decreases.

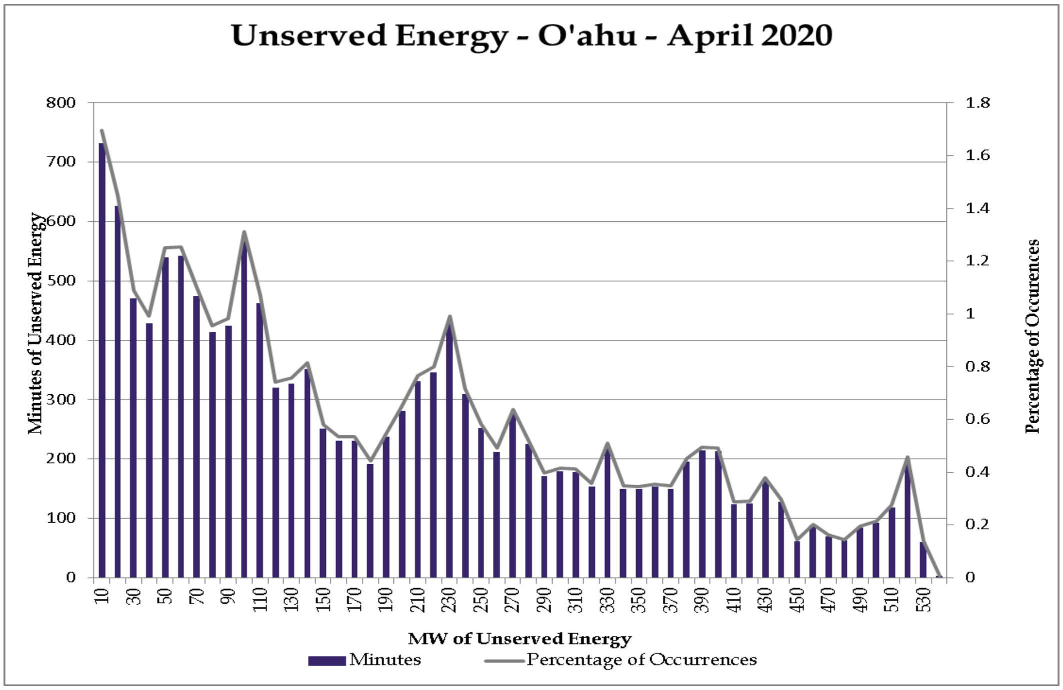

Figure K-15. Sub-Hourly Unserved Energy for the Post-April PSIP Plan on O'ahu at 1-Minute Look-Ahead

Figure K-16 shows the estimated unserved energy with a 15 minute look-ahead for the E3 plan. As shown, the unserved energy magnitude and number of occurrences significantly decreases with 15 minute look-ahead.

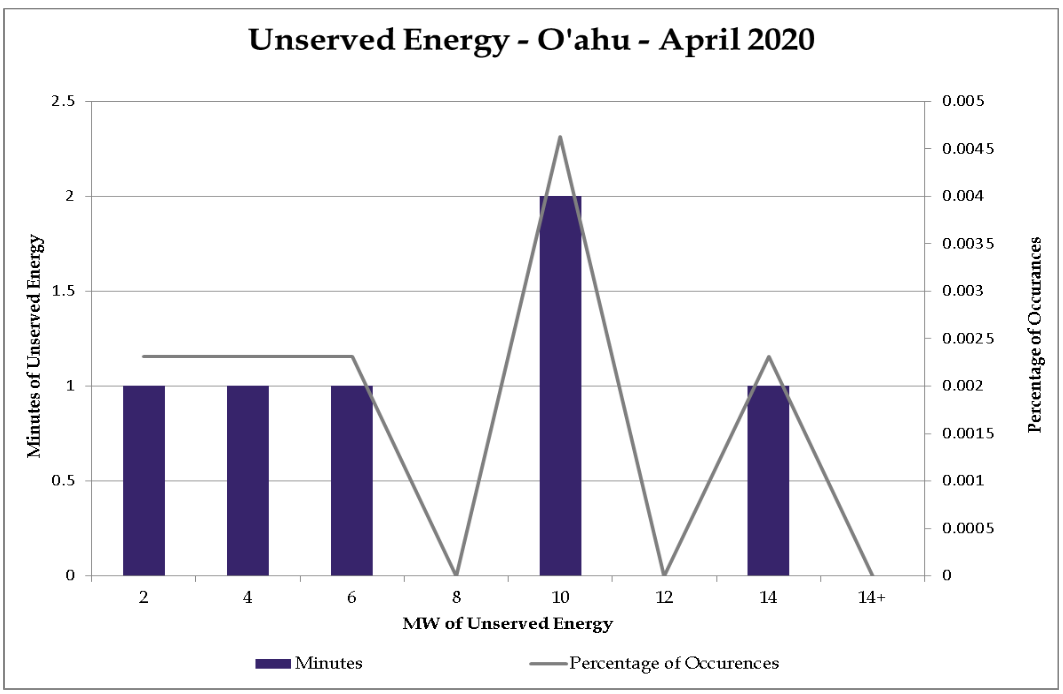

Figure K-16. Sub-Hourly Unserved Energy for E3 Plan on O'ahu at 15-Minute Look-Ahead

Figure K-17 shows the estimated unserved energy with a 15 minute look-ahead for the Post-April plan.

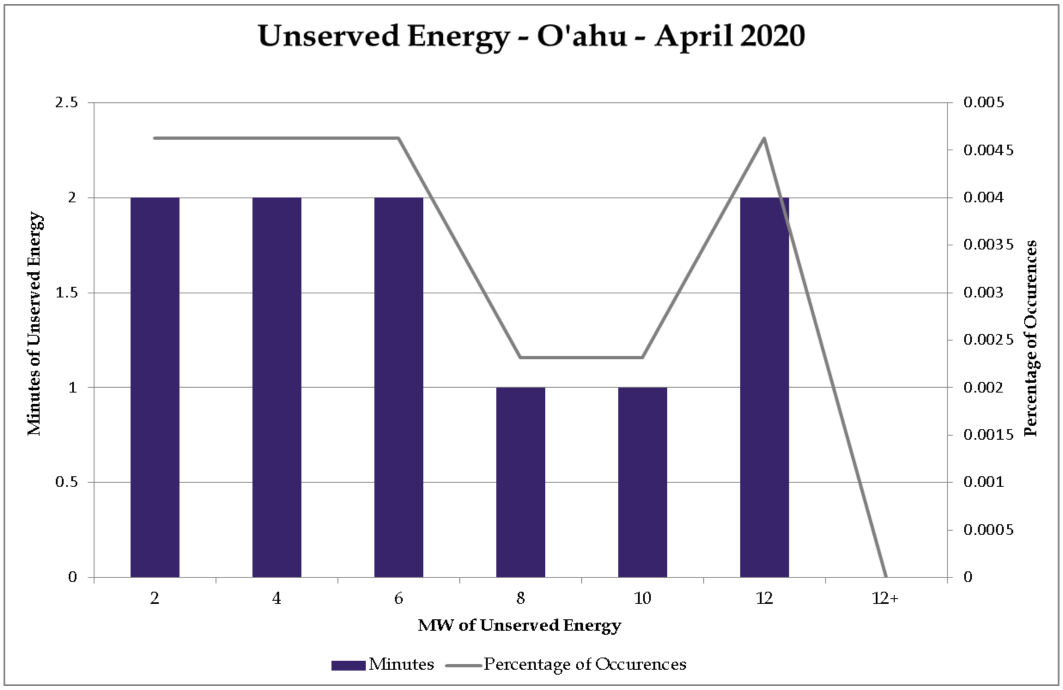

Figure K-17. Sub-Hourly Unserved Energy for the Post-April PSIP Plan on O'ahu at 15-Minute Look-Ahead

With a 30 minute look-ahead setting, there is virtually no unserved energy.

Daily Energy Charts of O'ahu Plans

The charts in the previous sections displayed annual and monthly views of how renewable energy is integrated into the plans and the impacts to the system energy production. This section will convey a more granular view by illustrating the energy mix for select days of some years of the plans that were modeled.

High Over-Generation Energy Profiles for E3 Plan with Generation Modernization

Figure K-18 provides a view of the day in the year 2020 that has the highest amount of over-generation for the E3 Plan with Generation Modernization.

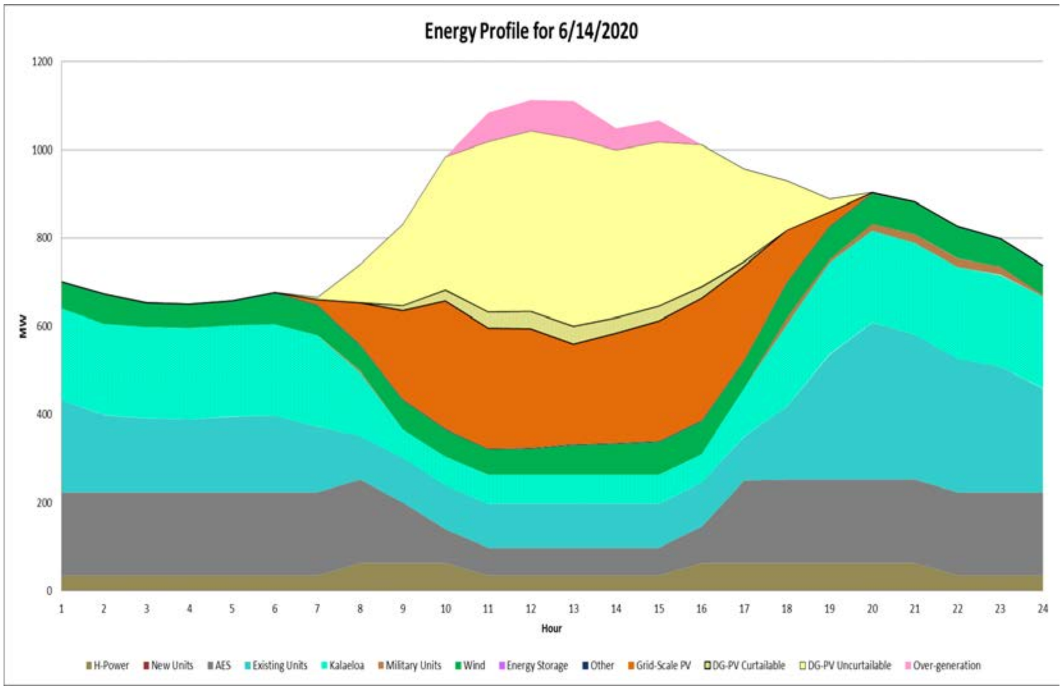

Figure K-18. E3 Plan with Generation Modernization O'ahu High Over-Generation Energy Profile: 2020

The day in 2030 that has the highest amount of over-generation for the E3 Plan with Generation Modernization is shown in Figure K-19. It can be seen that during the middle of the day, almost all of the load is being served by renewable energy and that the storage is being charged during that time. The energy storage is then dispatched in the evening.

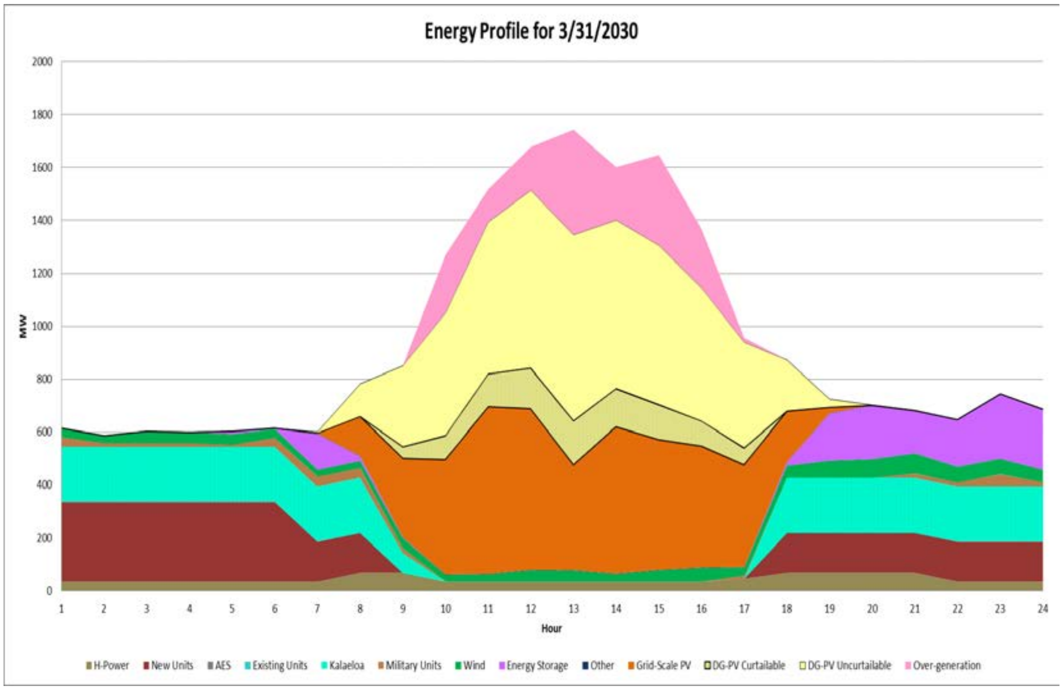

Figure K-19. E3 Plan with Generation Modernization O'ahu High Over-Generation Energy Profile: 2030

Figure K-20 shows that there is more over-generation in 2040, and by 2045, there is over-generation occurring for many hours shown in Figure K-21.

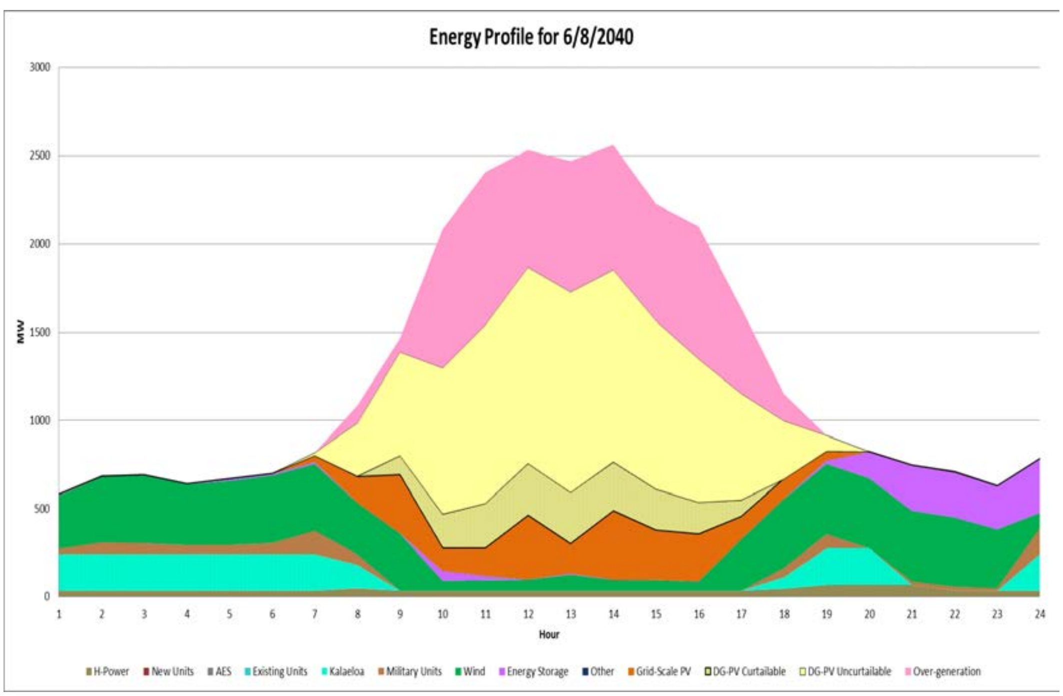

Figure K-20. E3 Plan with Generation Modernization O'ahu High Over-Generation Energy Profile: 2040

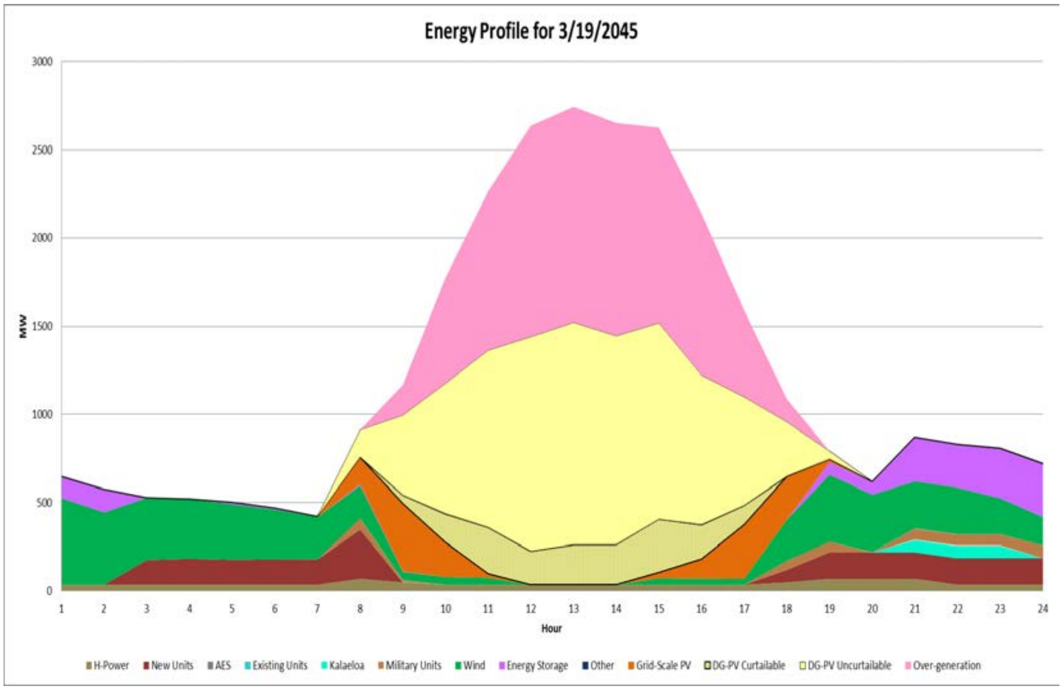

Figure K-21. E3 Plan with Generation Modernization O‘ahu High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for E3 Plan with Generation Modernization

Although Hawai‘i has abundant renewable resources, such as wind and solar, there are days for which there is limited solar and/or limited or no wind available. Figure K-22, Figure K-23, Figure K-24, and Figure K-25 illustrate how different the energy profile is on days with low renewable energy available in the years 2020, 2030, 2040, and 2045, respectively, for the E3 Plan with Generation Modernization. Even in later years, such as 2040 and 2045, where there are significant amounts of renewable resources and energy storage included in the plan, on these low renewable days, thermal generation is still necessary to serve the load.

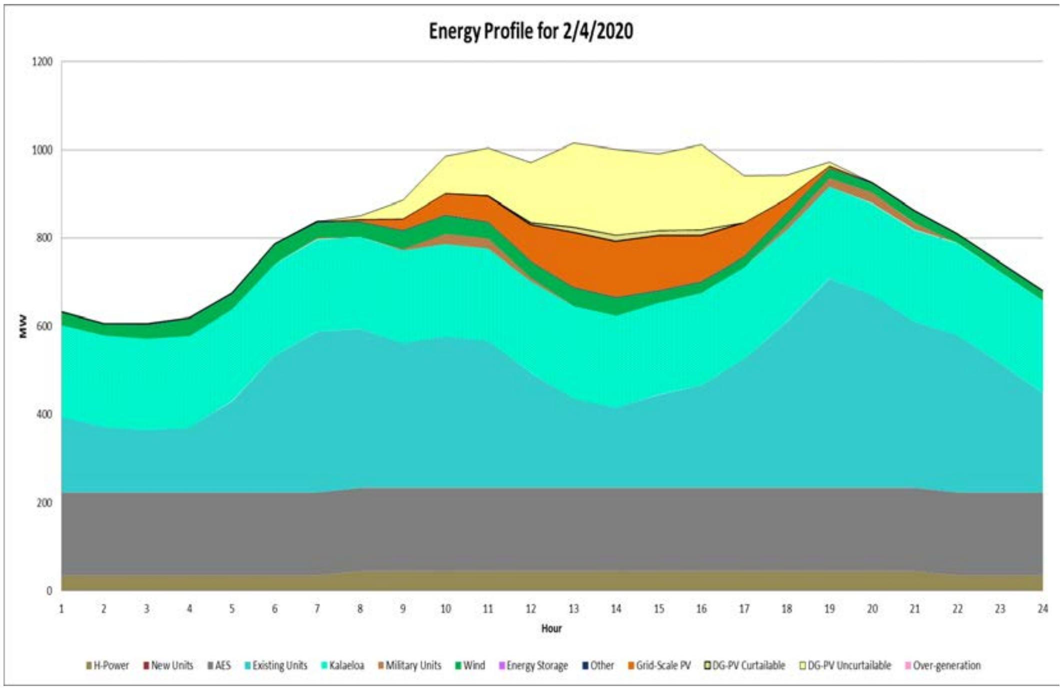

Figure K-22. E3 Plan with Generation Modernization O'ahu Low Renewables Energy Profile: 2020

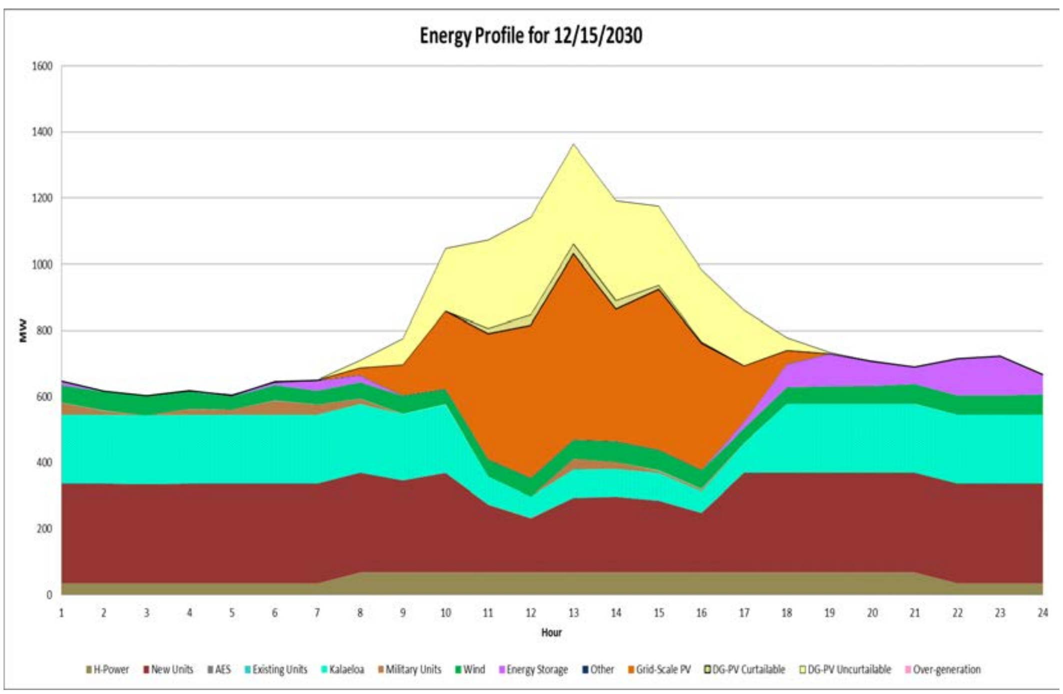

Figure K-23. E3 Plan with Generation Modernization O'ahu Low Renewables Energy Profile: 2030

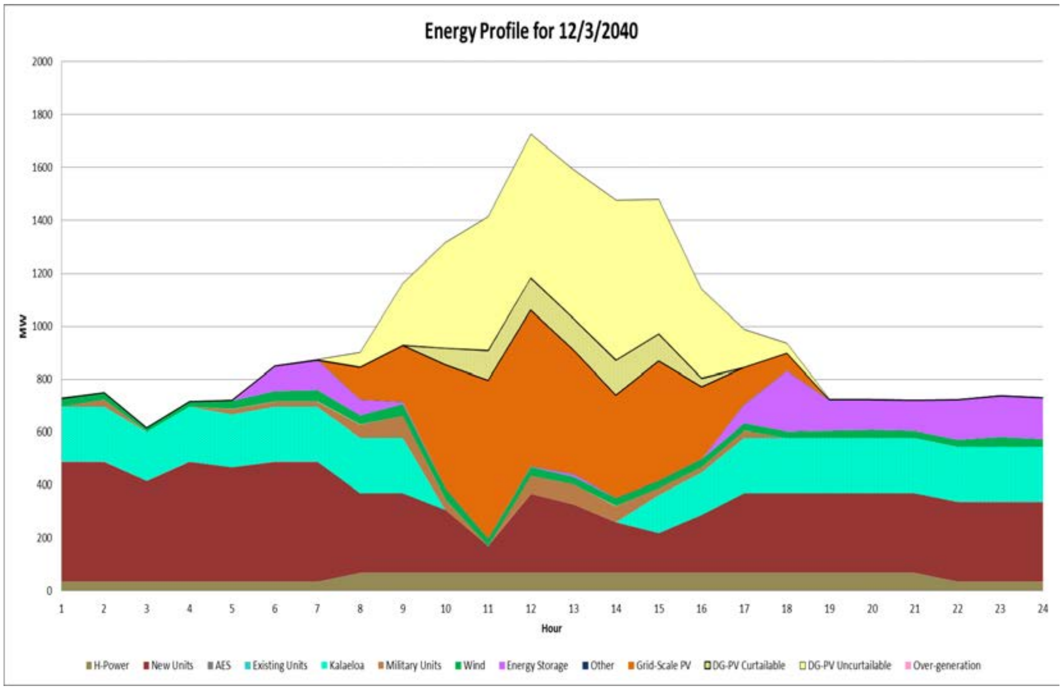

Figure K-24. E3 Plan with Generation Modernization O'ahu Low Renewables Energy Profile: 2040

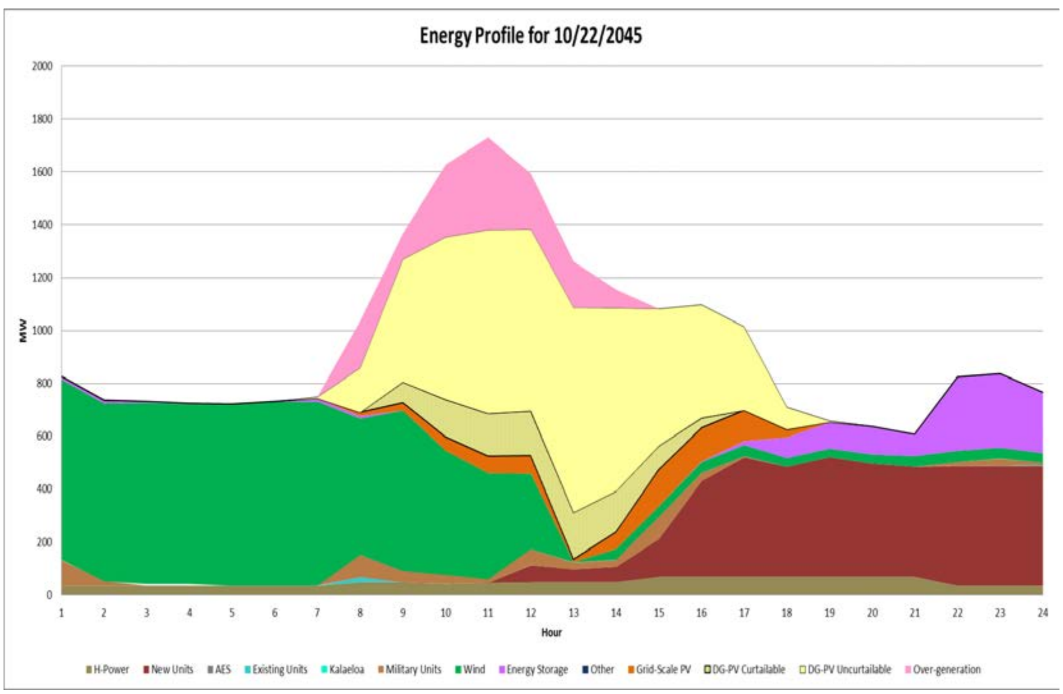

Figure K-25. E3 Plan with Generation Modernization O'ahu Low Renewables Energy Profile: 2045

High Over-Generation Energy Profiles for Post-April PSIP Plan

Since the Post-April PSIP Plan has a different resource mix than the E3 plans, the daily energy profiles for the same years (2020, 2030, 2040, and 2045) are provided below.

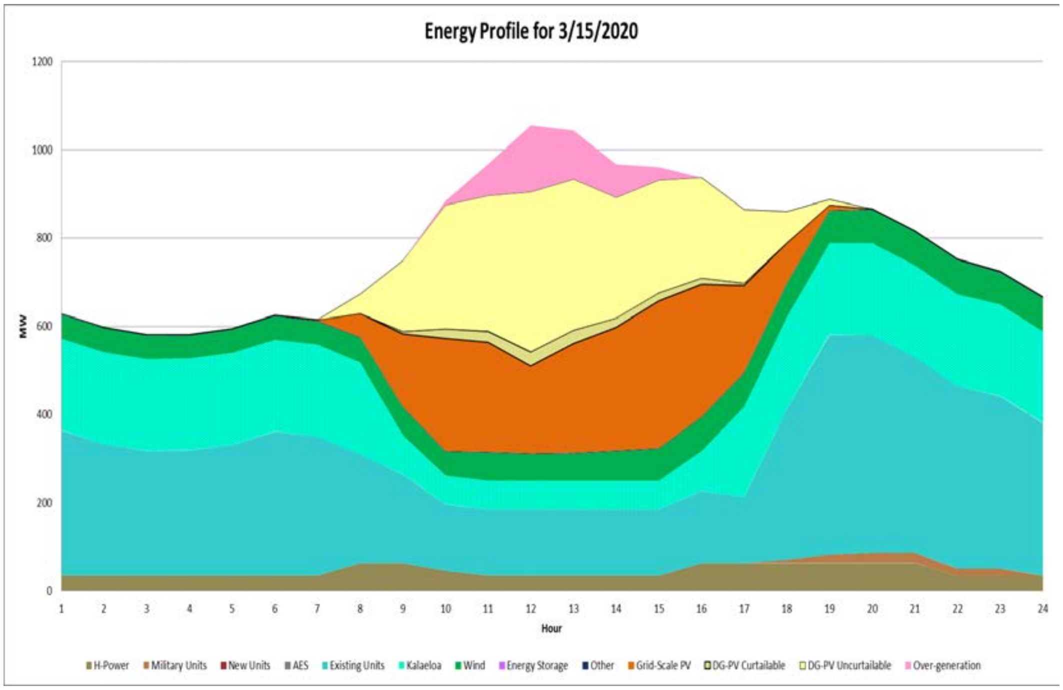

Figure K-26. Post-April PSIP Plan O'ahu High Over-Generation Energy Profile: 2020

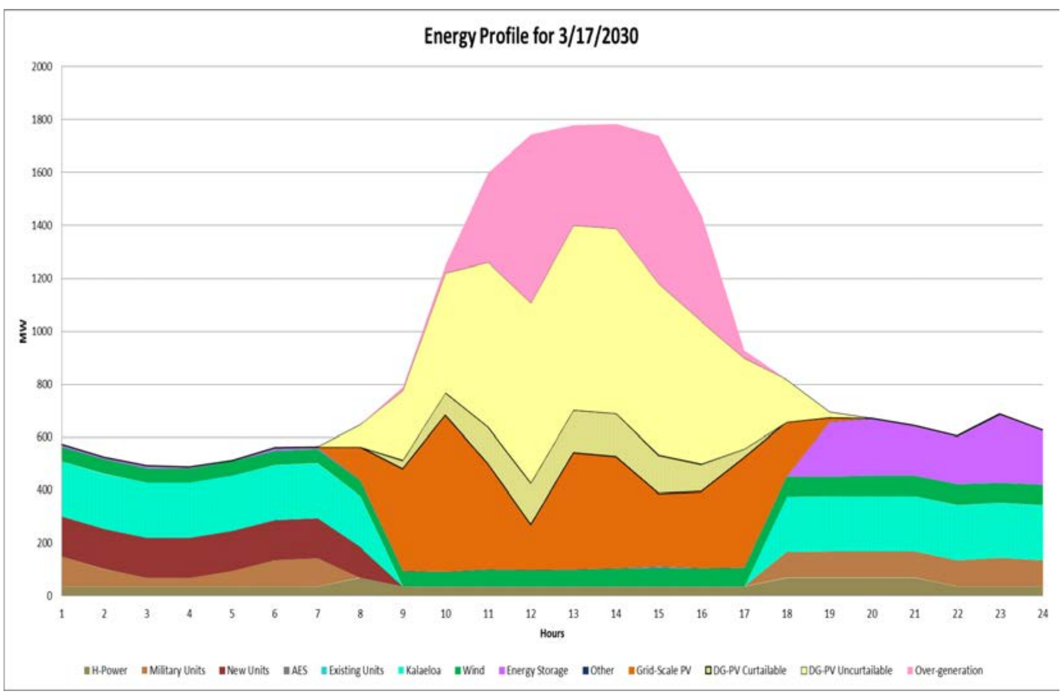

Figure 4-27. Post-April PSIP Plan O'ahu High Over-Generation Energy Profile: 2030

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

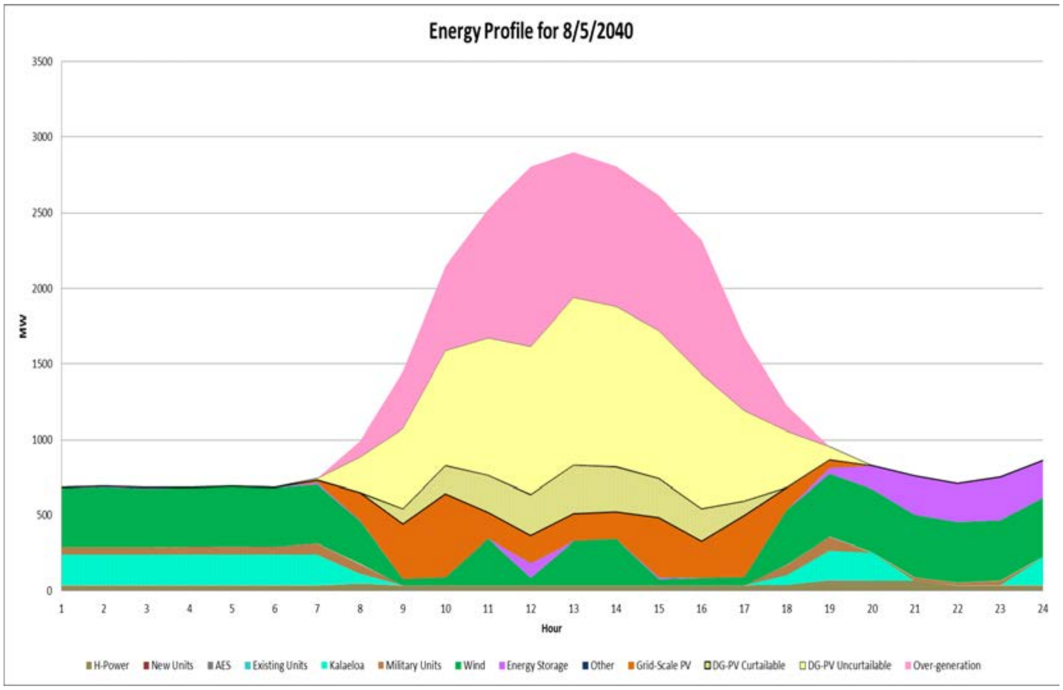

Figure K-28. Post-April PSIP Plan O'ahu High Over-Generation Energy Profile: 2040

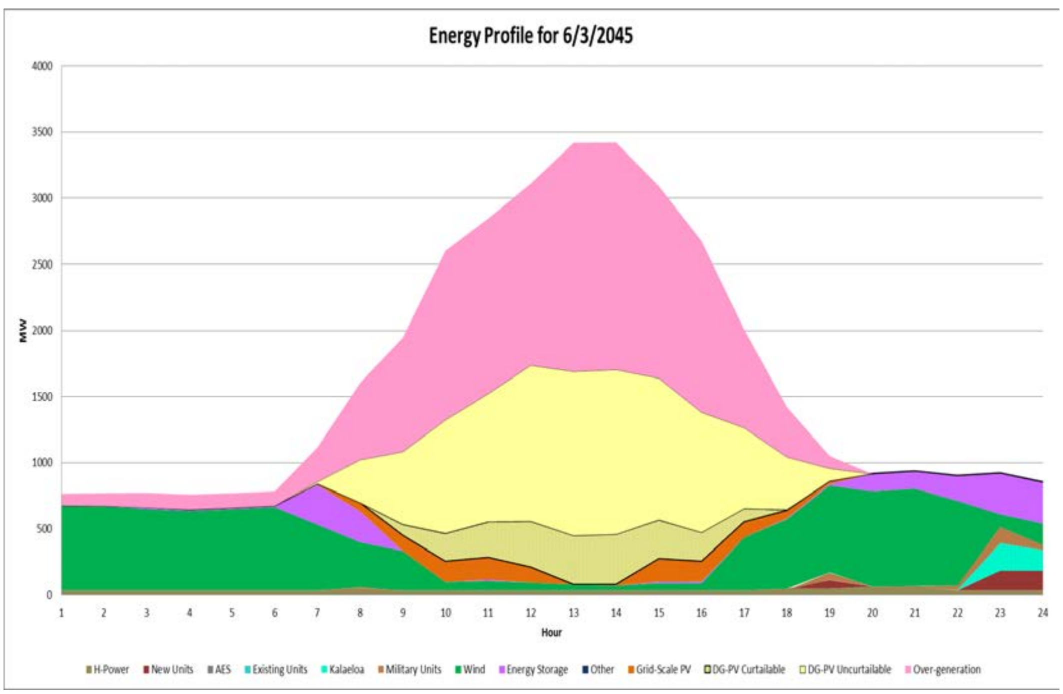

Figure K-29. Post-April PSIP Plan O'ahu High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for Post-April PSIP Plan

The daily energy profiles for the same years (2020, 2030, 2040, and 2045) for the Post-April PSIP Plan are provided below as a comparison to the E3 plans.

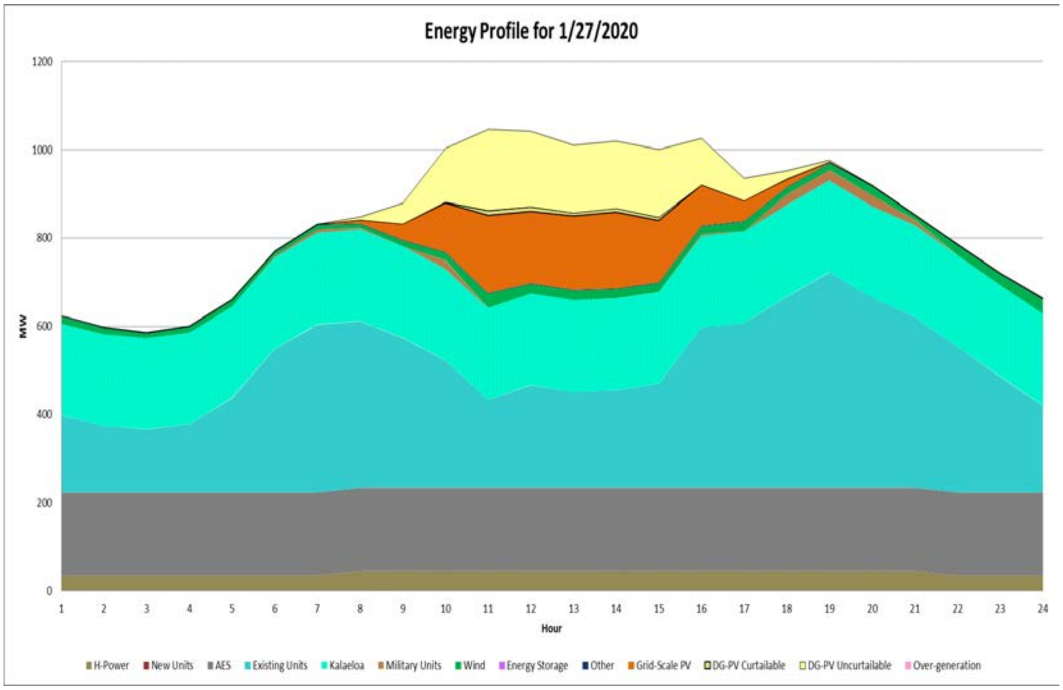

Figure K-30. Post-April PSIP Plan O'ahu Low Renewables Energy Profile: 2020

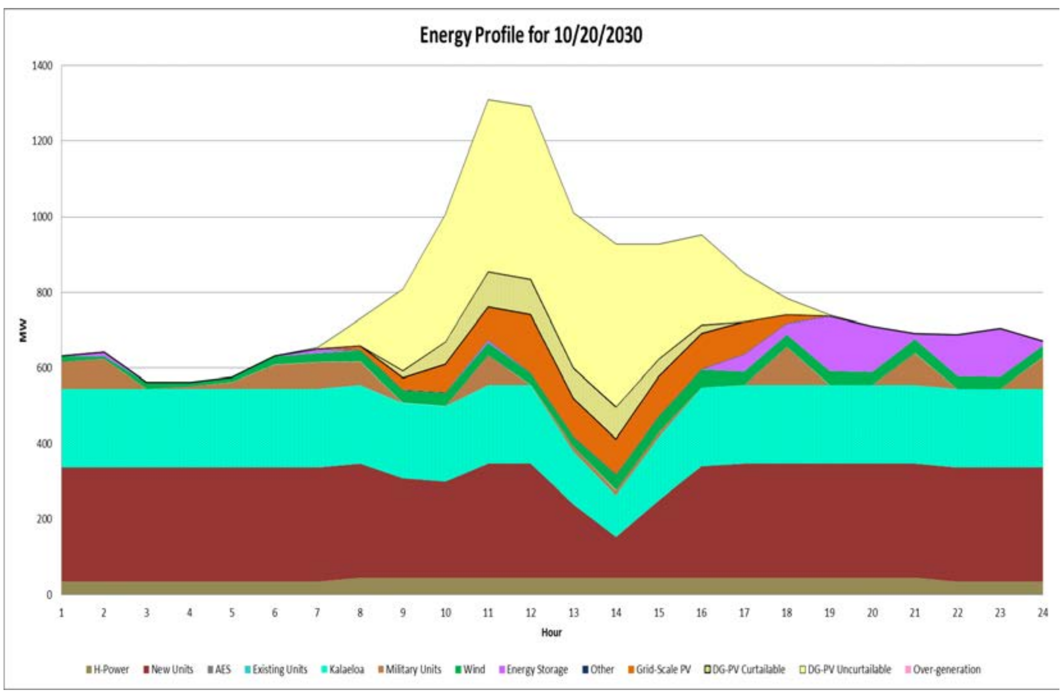

Figure K-31. Post-April PSIP Plan O'ahu Low Renewables Energy Profile: 2030

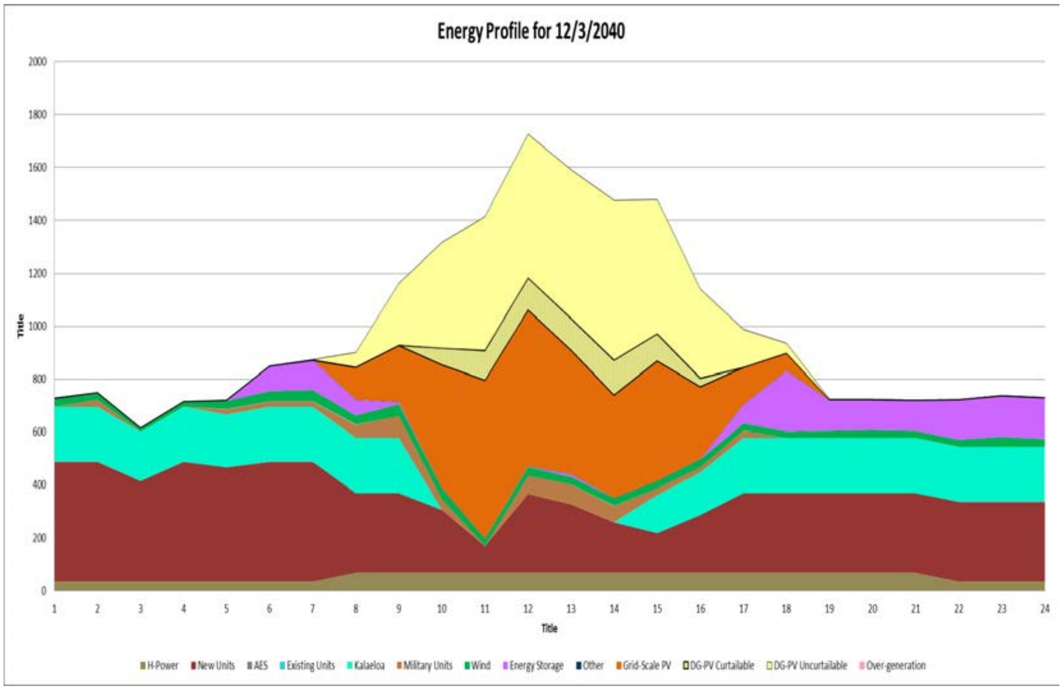

Figure K-32. Post-April PSIP Plan O'ahu Low Renewables Energy Profile: 2040

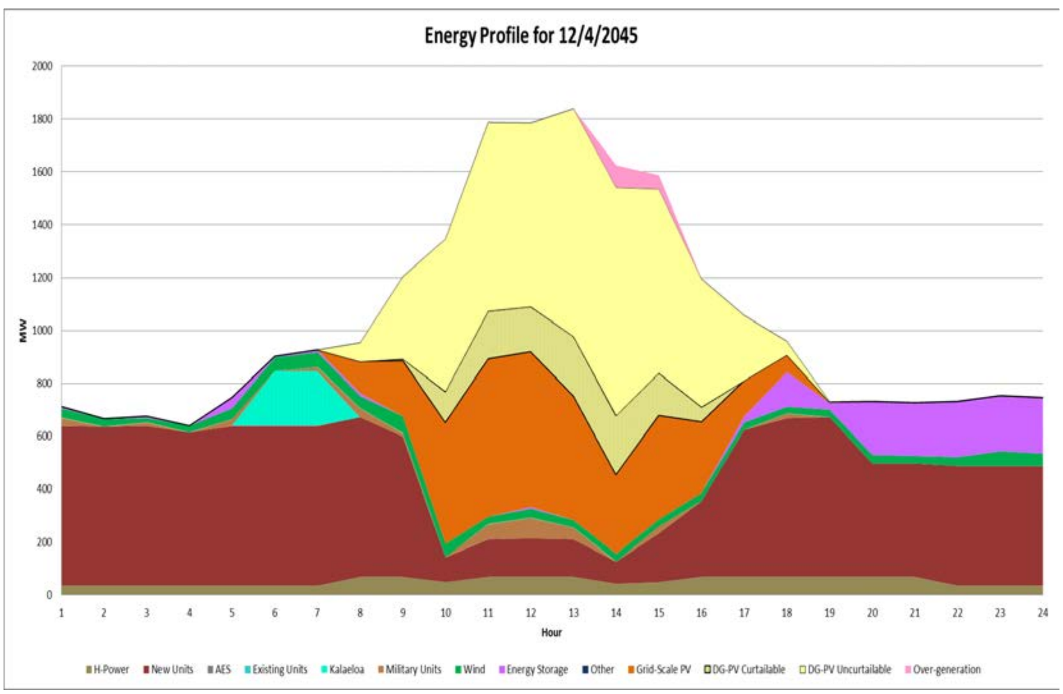

Figure K-33. Post-April PSIP Plan O'ahu Low Renewables Energy Profile: 2045

MAUI ANALYTICAL STEPS AND RESULTS

The core cases analyzed for Maui outline different paths to achieving 100% renewable energy in 2045 as well as an accelerated target of 2040 consistent with the April 2016 PSIP.

Energy Mix of Maui Plans

Figure K-34 summarizes the annual RPS for each year.

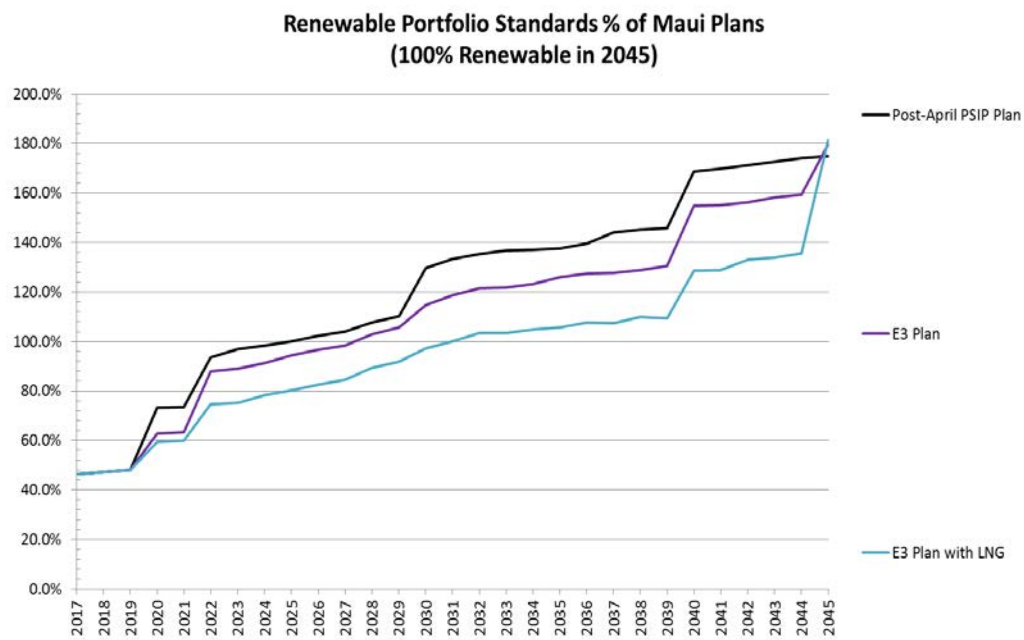

Figure K-34. Renewable Portfolio Standards Percent of Maui Plans

The calculation of the RPS per the law does result in values over 100%. To emphasize that we are committed to achieving 100% renewable energy in 2045, Figure K-35 shows the renewable energy as a percent of total energy including customer-sited generation.

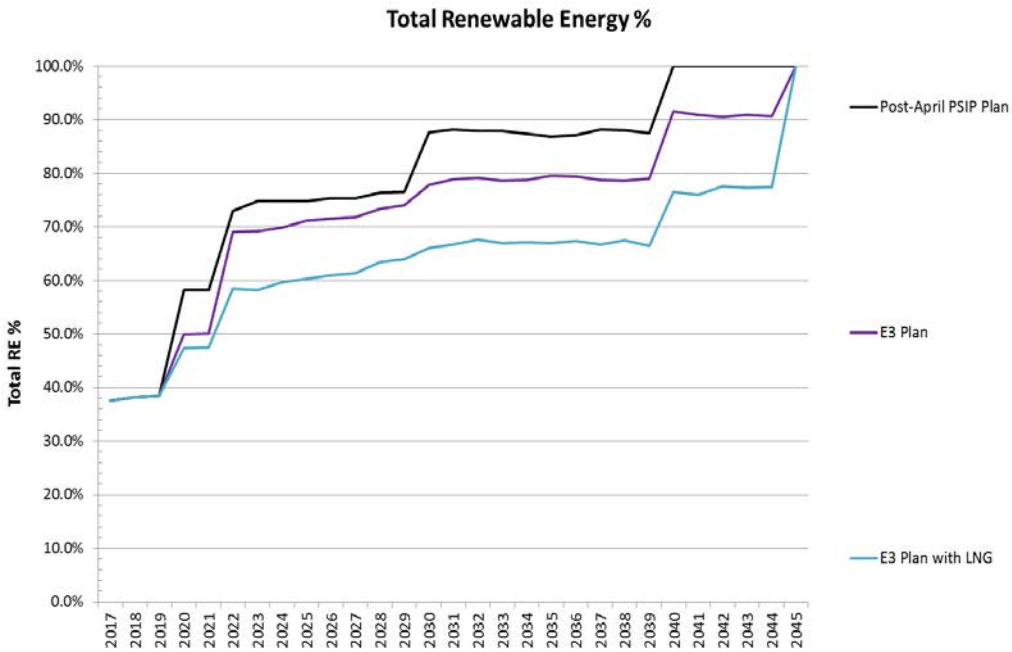

Figure K-35. Total Renewable Energy Percent of Maui Plans

The resource mix for the plans changes over time as it reaches 100% renewable in 2045 for the E3 plans and 100% renewable in 2040 for the Post-April PSIP Plan.. The figures below reveal how the energy mix in each plan grows to 100% renewable energy.

The annual energy served by resource type is shown in Figure K-36 for the Post-April PSIP Plan. The transition to renewable wind and solar can be easily seen as the fossil fuel (oil) significantly decreases over time.

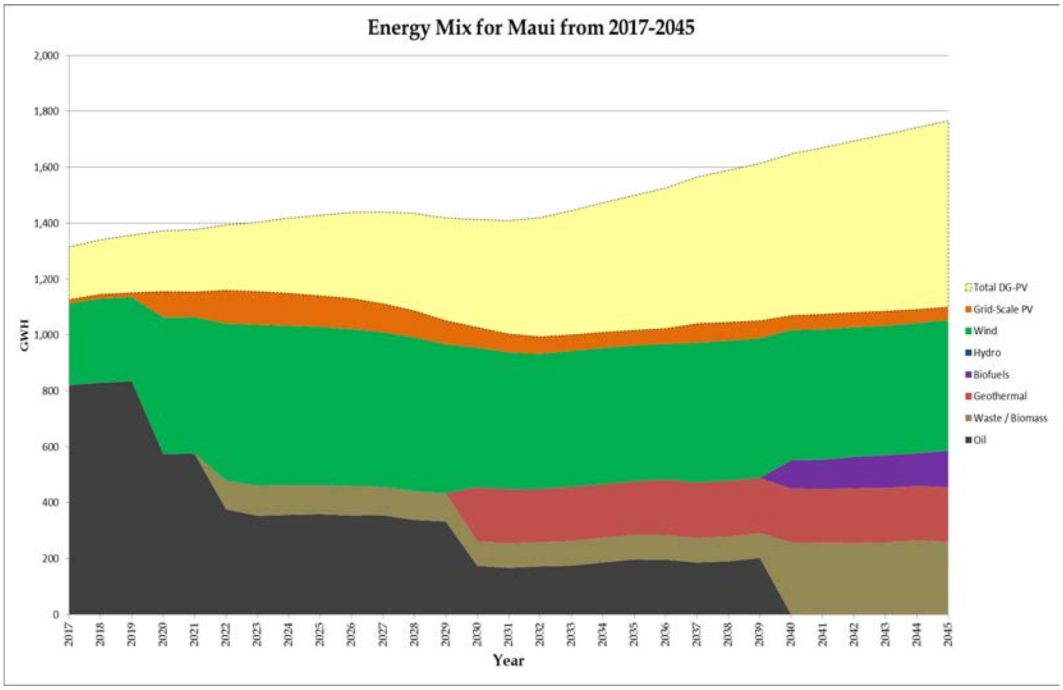

Figure K-36. Energy Mix for Post-April PSIP Plan on Maui

Figure K-37 shows the energy mix of the E3 Plan.

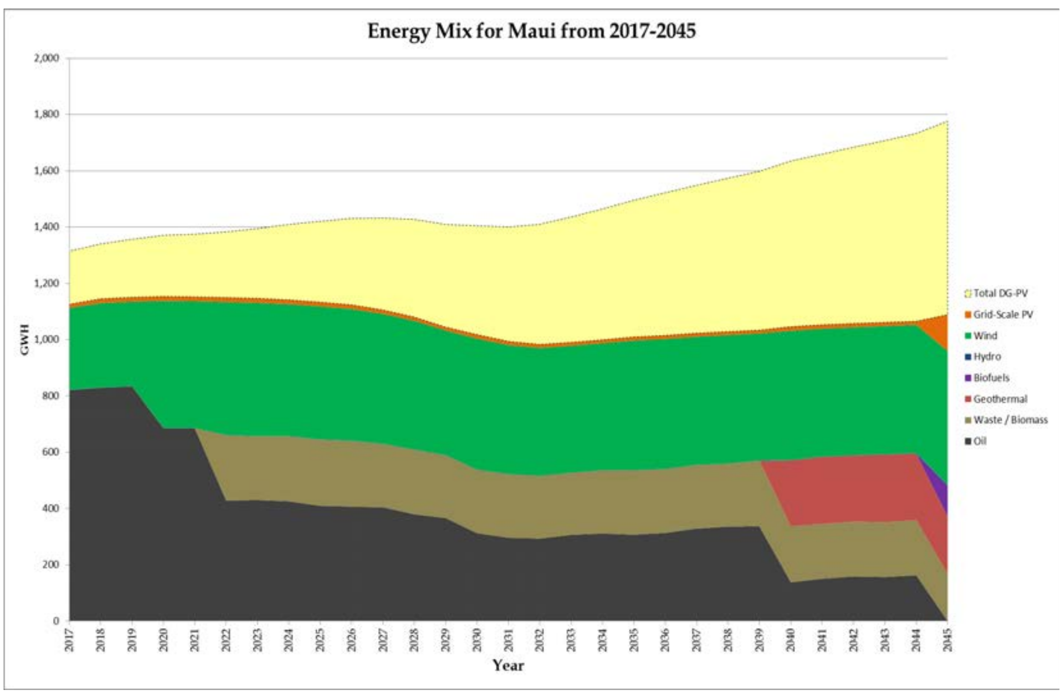

Figure K-37. Energy Mix for E3 Plan on Maui

The E3 Plan with LNG uses LNG as a transitional fuel from oil. Renewable energy is added economically to meet intermediate RPS targets and ultimately 100% renewable energy in 2045. The energy mix for E3 Plan with LNG is shown in Figure K-38. The

transition to LNG assumes a contract period of 2022–2041. During the last intervening years in the transition to 100% renewable energy, potential future resources at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

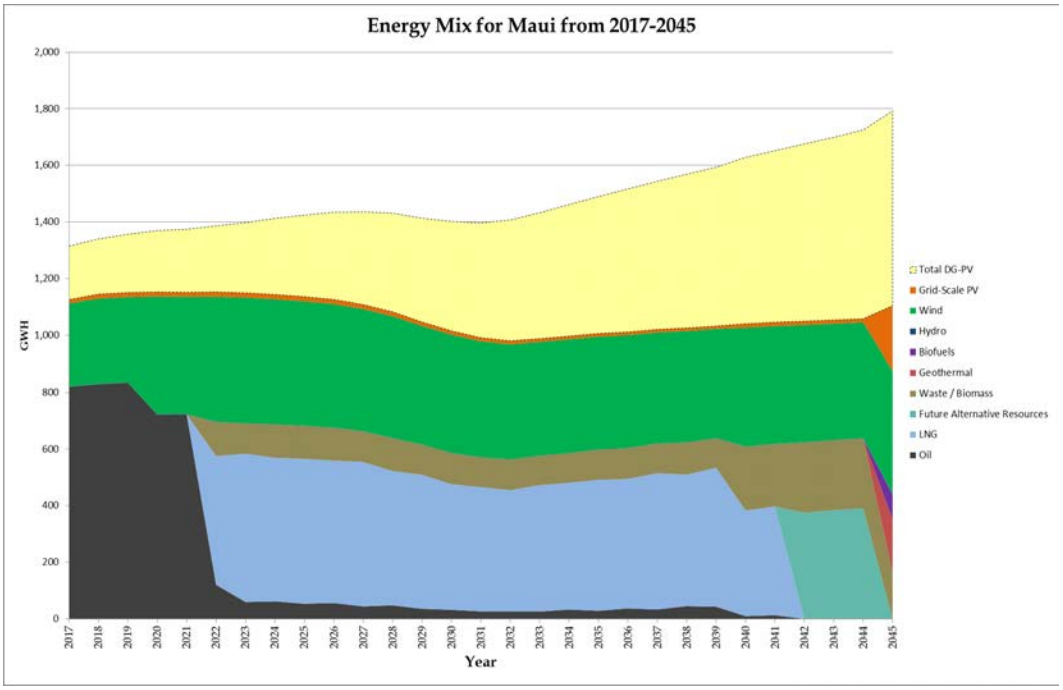

Figure K-38. Energy Mix for E3 Plan with LNG on Maui

Percent Over-Generation of Total System for Maui Plans

As increasingly more renewable energy is added to the system, over-generation occurrences will become inevitable. Figure K-39 provides estimates of the percent over-generation of the total system annual energy for the various plans. Since the Post-April PSIP Plan integrates greater amounts of grid-scale PV and grid-scale wind energy than the E3 plans, the percent over-generation is significantly higher in the Post-April PSIP Plans than in the E3 plans. Although the E3 plans add energy storage which aids in reducing over-generation, over-generation still occurs. However, situations of over-generation provide opportunities, coupled with appropriate controls systems, to allow wind and solar generation to contribute to regulation up resources in addition to use as a reserve resource. This provides improved system performance. In combination, wind and solar used for energy and some level of regulation and reserve appears to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this December 2016 PSIP update (similar to the April 2016 PSIP update), we include the full cost of the grid-scale wind and grid-scale PV resources in cost calculations, regardless of over-generation levels and provide a simplified accounting for other services from these resources.

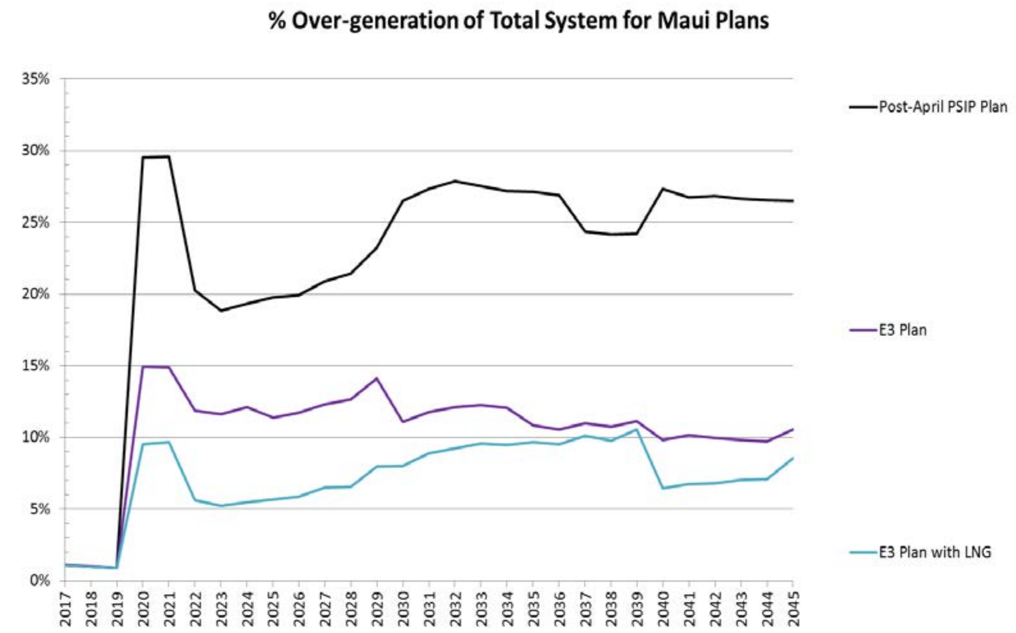

Figure K-39. Total System Over-Generation Percent for Maui Plans

Unserved Energy of Maui Plans

While periods of over-supply exist as described above, periods of unserved energy can also occur. The plans evaluate whether sufficient generation to serve load exists with variable renewable energy and storage with minimal conventional thermal resources on the system. The E3 plans identified existing conventional thermal generating units that could be considered for removal from service as an economic option. For the PLEXOS modeling of the E3 plans, these units were made unavailable to serve load or "offline". If there was sufficient generation being provided by the remaining thermal resources, variable renewable resources, and storage, then there would not be any unserved energy. For the E3 Plan and Post-April PSIP Plan, there was virtually no unserved energy in the planning period.

Seasonal Variations of Maui Renewable Energy

Although Maui has firm renewable resource options available, the majority of existing renewable energy is supplied through grid-scale wind that is highly seasonal as illustrated in the figures below.

Figure K-40 shows the difference between the load and the available renewable energy in the year 2025 for the E3 Plan. The difference must be met with thermal generation to prevent unserved energy.

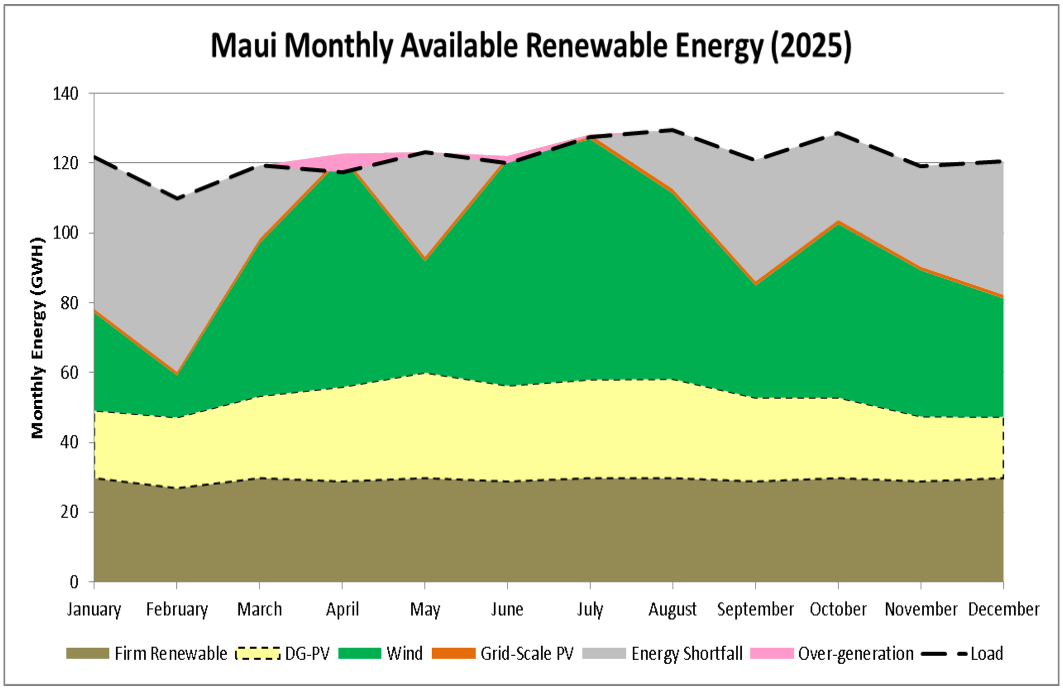

Figure K-40. E3 Plan Monthly Available Renewable Energy vs Load on Maui in 2025

Figure K-41 shows the difference between the load and the available renewable energy in the year 2045 for the E3 Plan. Despite having high amounts of renewable energy available in some months, creating a surplus, shown in pink, there are some months for which there is a deficit, shown in gray. This highlights the continued need for thermal generators to provide supplemental generation during these shortfall periods or energy storage systems, which are capable of shifting energy over several months from the months where there is a surplus to the months where there are shortfalls.

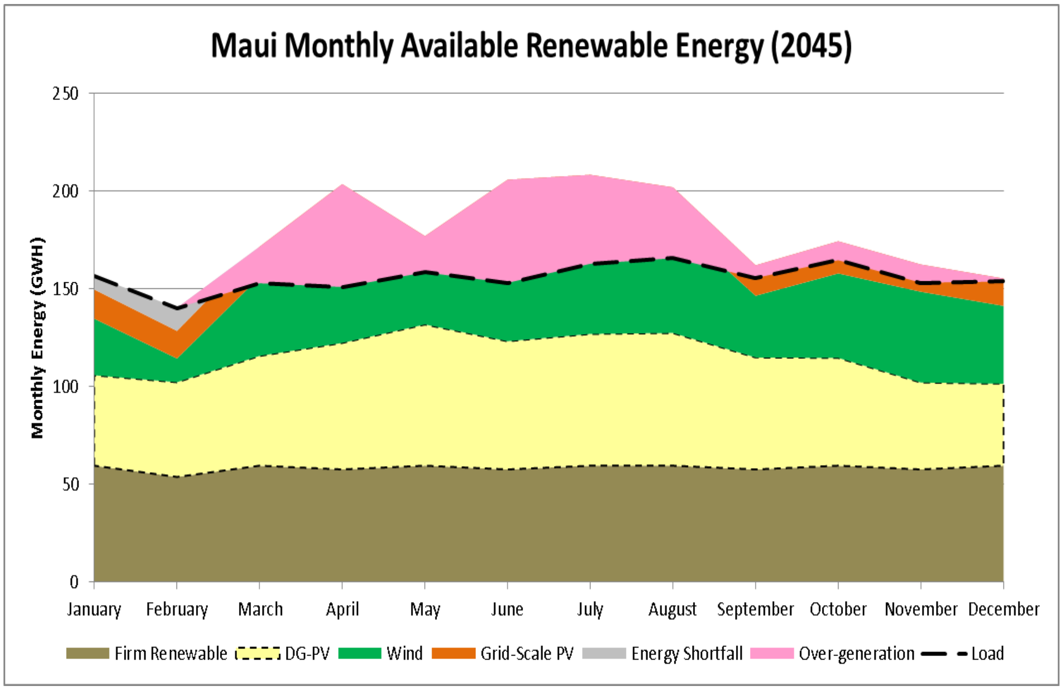

Figure K-41. E3 Plan Monthly Available Renewable Energy vs Load on Maui in 2045

Sub-Hourly Charts of Maui Plans

Sub-hourly modeling was performed to analyze the impact that variable renewable energy would have on our system, and whether our portfolio of generators and storage systems would be sufficient to stabilize the electrical grid.

Historical minutely renewable energy data was used to determine the volatility of solar and wind resources on Maui. The volatility of the KWP1 wind farm was applied to future grid-scale wind resources, and the volatility of DG-PV was applied to future grid-scale PV resources.

An initial screening was done to determine the month with the largest potential minutely downward ramp. PLEXOS was then employed to perform a stochastic analysis on this month. Using the historical minutely data, stochastic variables were created for all as-available resources and the load. Shown below are the results from the sub-hourly analysis of the E3 Plan when a 1-, 15-, and 30-minute look-ahead is assumed.

Figure K-42 shows the estimated unserved energy at a 1 minute look-head.

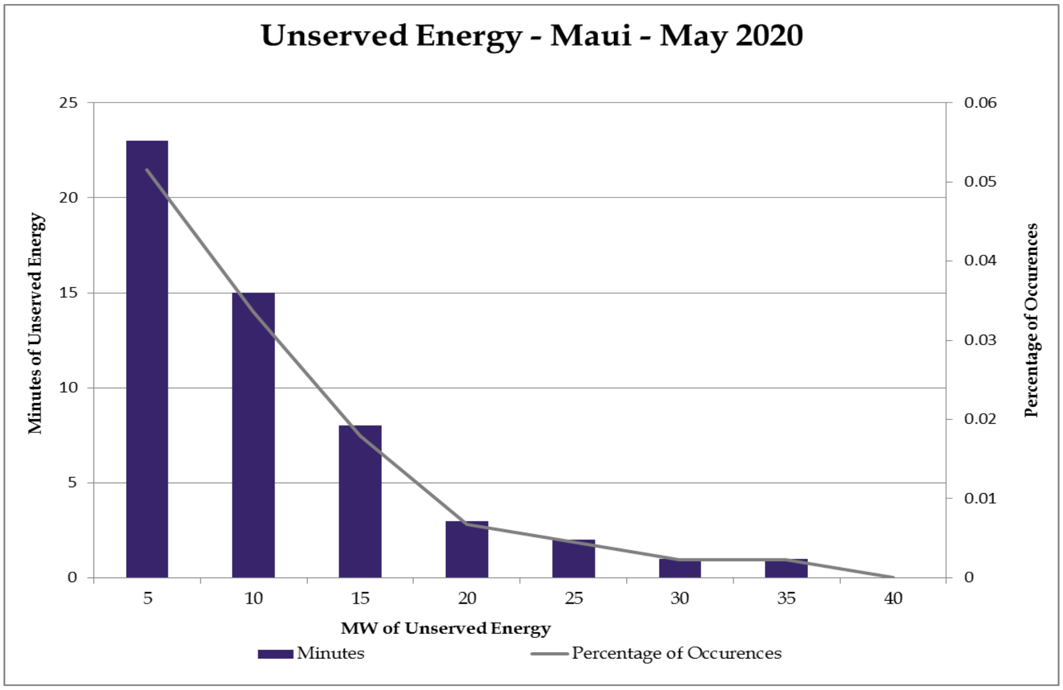

Figure K-42. Sub-Hourly Unserved Energy for E3 Plan on Maui at 1

As shown in Figure K-43, the unserved energy magnitude and number of occurrences significantly decreases with 15 minute look-ahead.

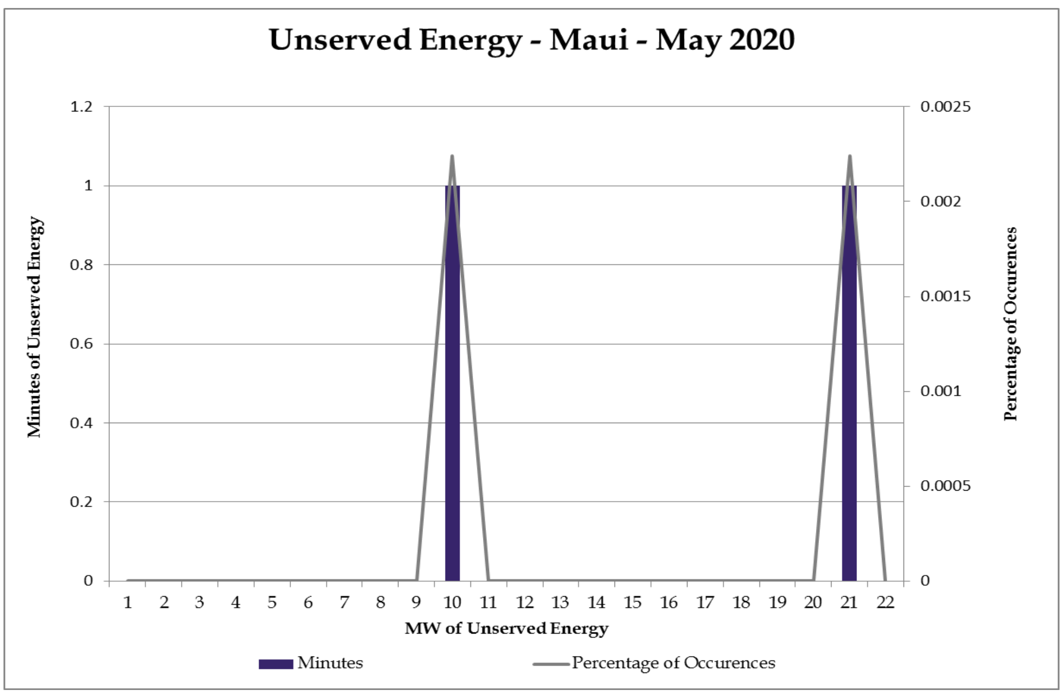

Figure K-43. Sub-Hourly Unserved Energy for E3 Plan on Maui at 15-Minute Look-Ahead

With a 30 minute look-ahead setting, there is virtually no unserved energy.

Daily Energy Charts of Maui Plans

The charts in the previous sections displayed annual and monthly views of how renewable energy is integrated into the plans and the impacts to the system energy production. This section will convey a more granular view by providing the energy mix for select days of some years of the plans that were modeled.

High Over-Generation Energy Profiles for E3 Plan

Figure K-44 provides a view of the day in the year 2020 that has the highest amount of over-generation for the E3 Plan.

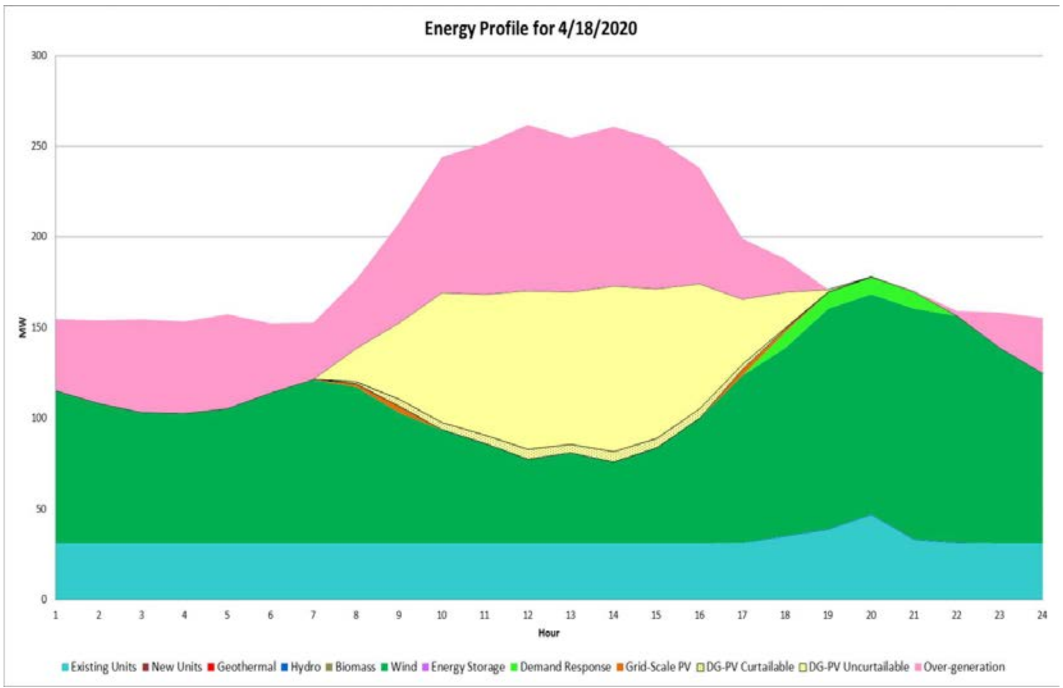

Figure K-44. E3 Plan Maui High Over-Generation Energy Profile: 2020

The day in 2030 that has the highest amount of over-generation for the E3 Plan is shown in Figure K-45. It can be seen that during the middle of the day, virtually all of the load is being served by renewable energy. The energy storage is being charged during the day during the periods of high over-generation and then discharged to serve load in the early morning and evening hours. .

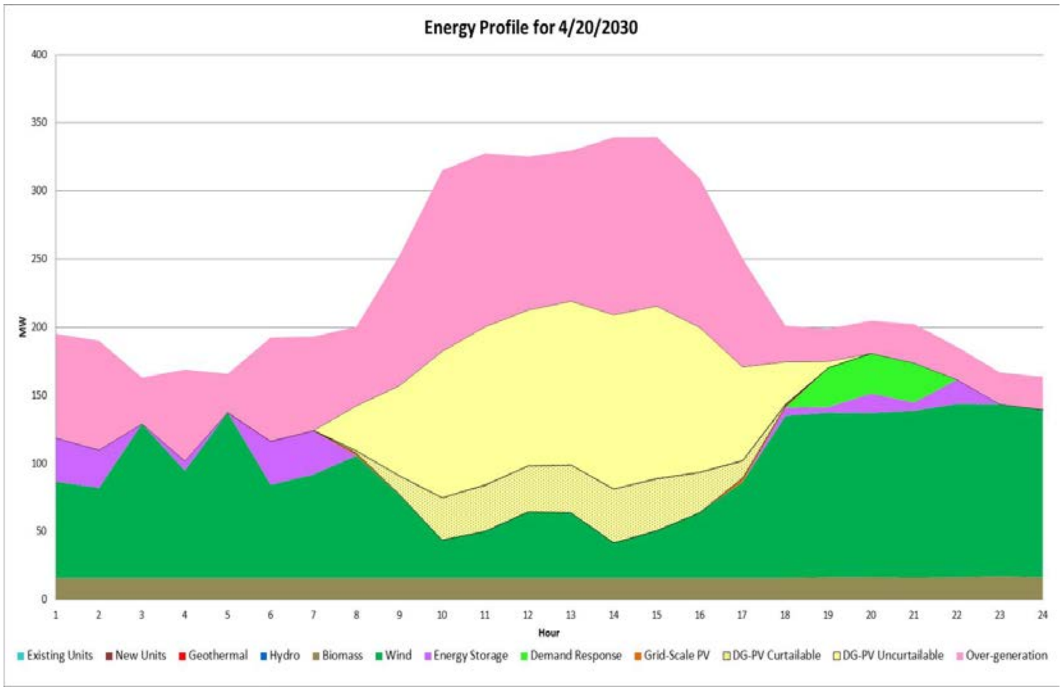

Figure K-45. E3 Plan Maui High Over-Generation Energy Profile: 2030

Figure K-46 and Figure K-47 show similar daily profiles in 2040 and 2045 as shown previously for 2030, but with more energy storage utilized.

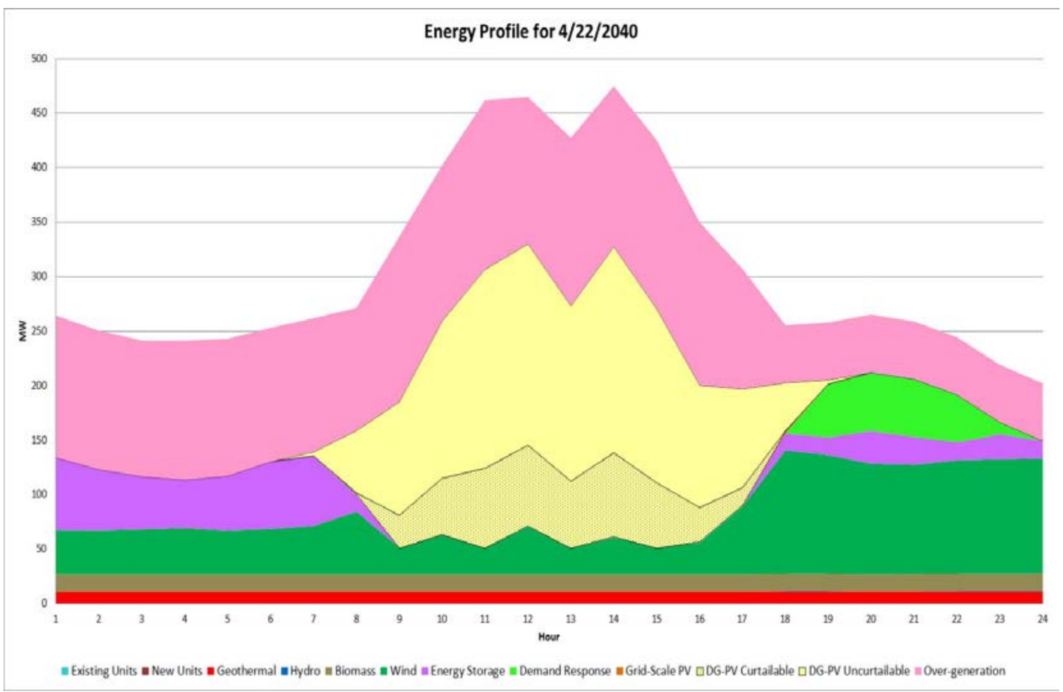

Figure K-46. E3 Plan Maui High Over-Generation Energy Profile: 2040

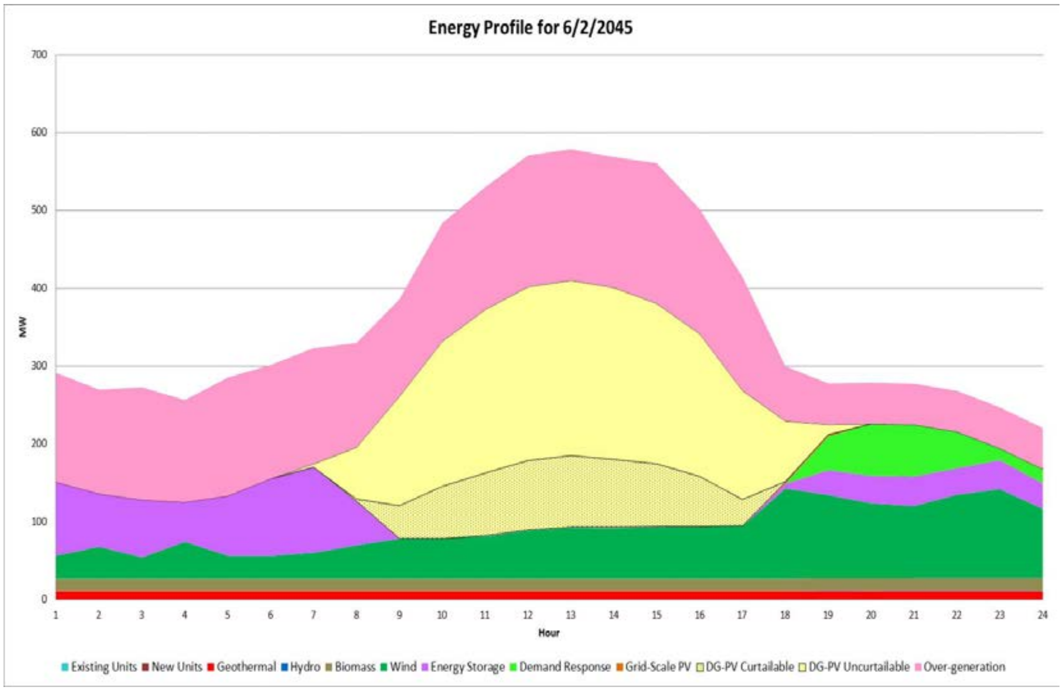

Figure K-47. E3 Plan Maui High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for E3 Plan

Although Hawai'i has abundant renewable resources, such as wind and solar, there are days for which there is limited solar and/or limited or no wind available. Figure K-48, Figure K-49, Figure K-50, and Figure K-51 illustrate how different the energy profile is on days with low renewable energy available in the years 2020, 2030, 2040, and 2045, respectively, for the E3 Plan. Even in later years, such as 2040 and 2045, where there are significant amounts of renewable resources and energy storage included in the plan, on these low renewable days, thermal generation is still necessary to serve the load.

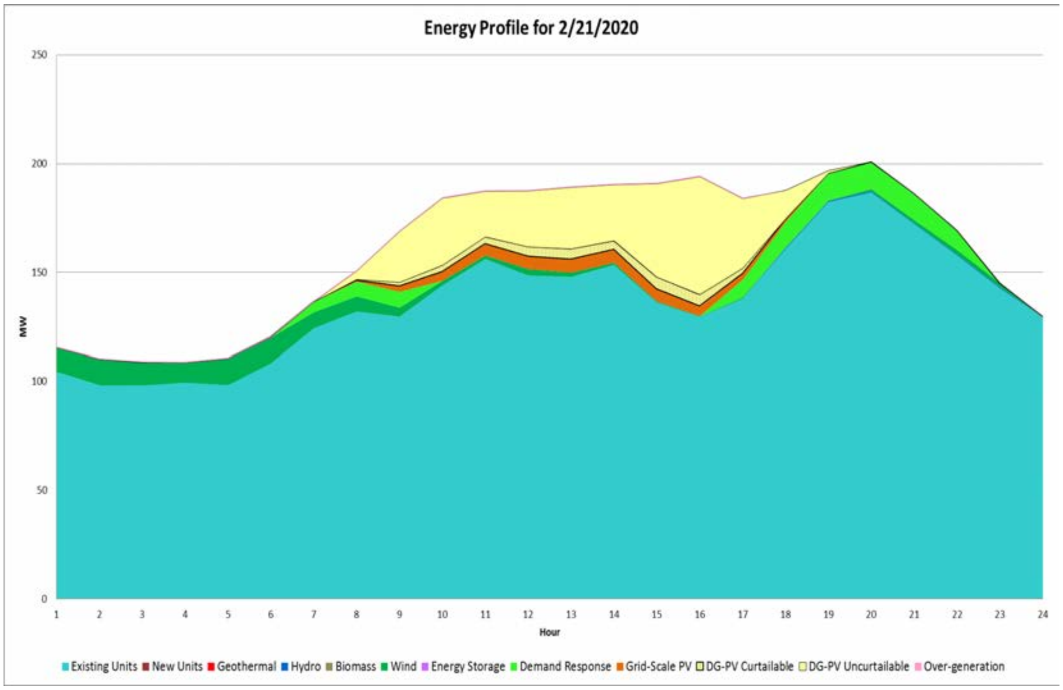

Figure K-48. E3 Plan Maui Low Renewables Energy Profile: 2020

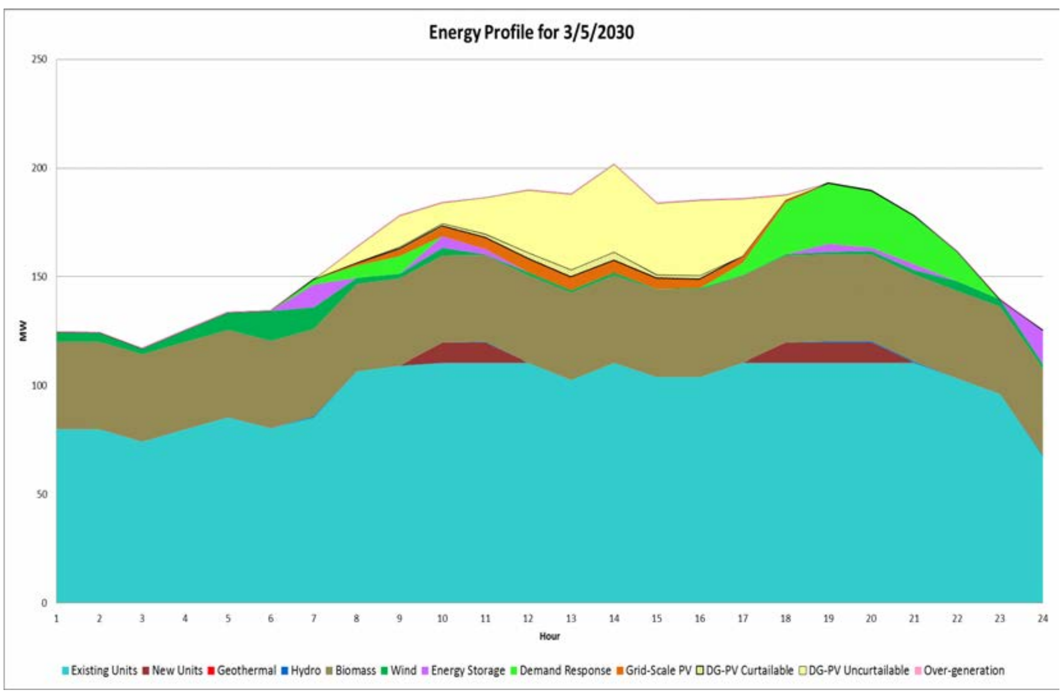

Figure K-49. E3 Plan Maui Low Renewables Energy Profile: 2030

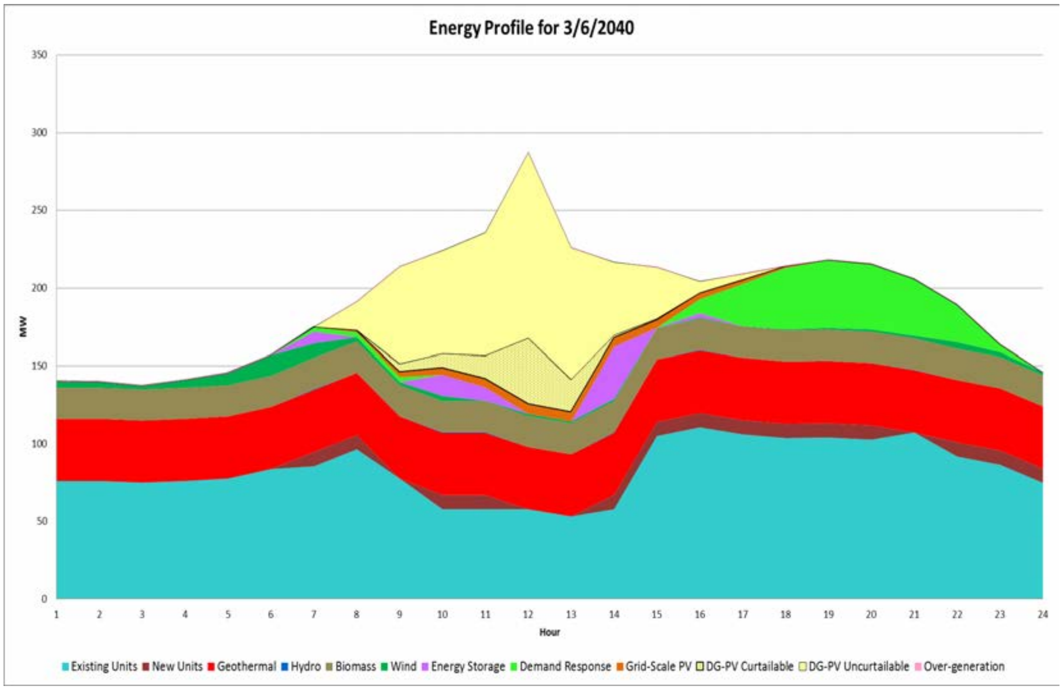

Figure K-50. E3 Plan Maui Low Renewables Energy Profile: 2040

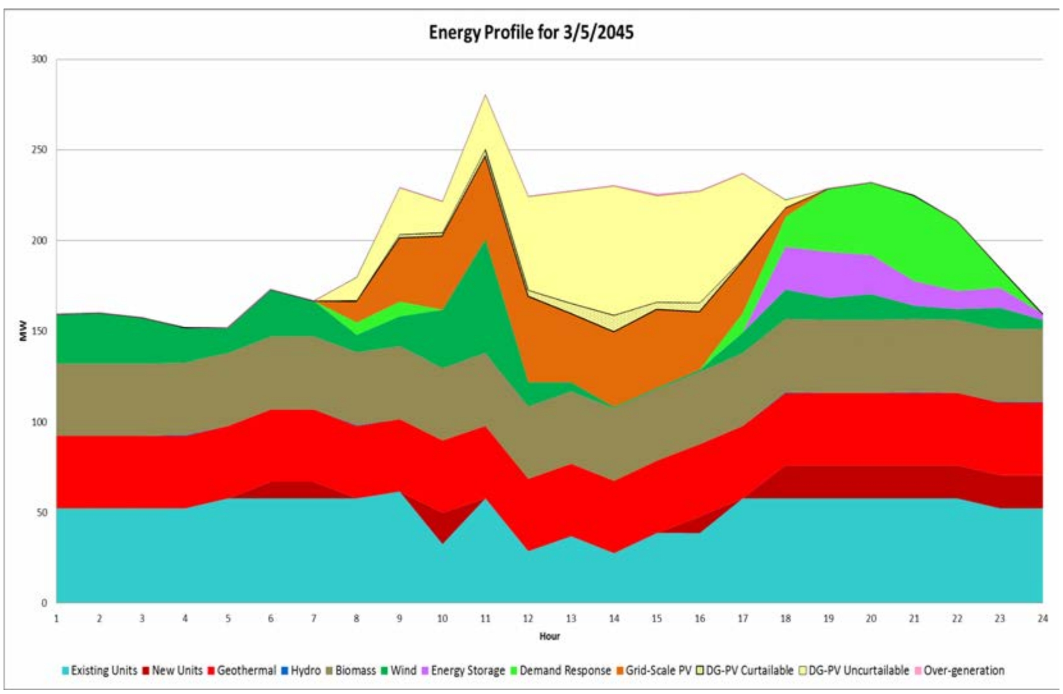

Figure K-51. E3 Plan Maui Low Renewables Energy Profile: 2045

High Over-Generation Energy Profiles for Post-April PSIP Plan

Since the Post-April PSIP Plan has a different resource mix than the E3 plans, the daily energy profiles for the same years (2020, 2030, 2040, and 2045) are provided below.

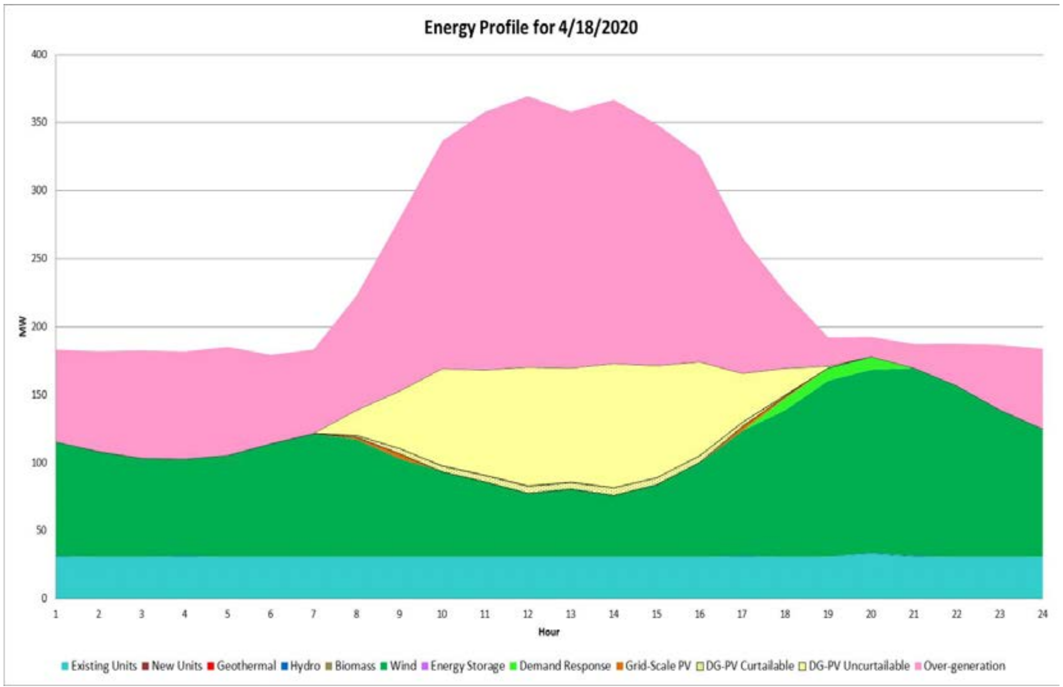

Figure K-52. Post-April PSIP Plan Maui High Over-Generation Energy Profile: 2020

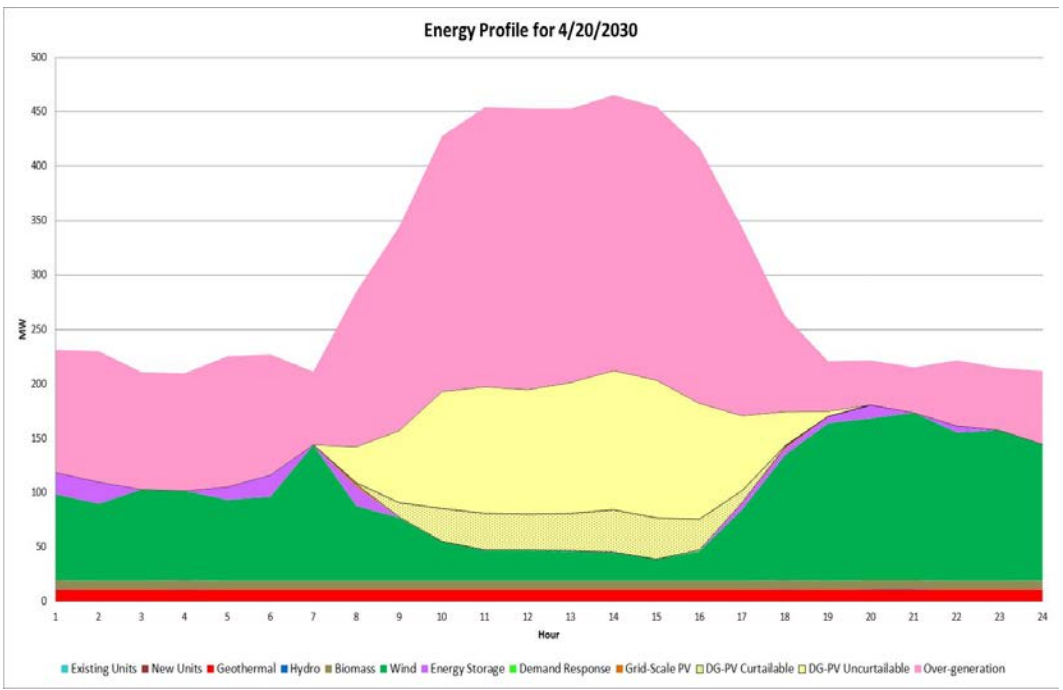

Figure 4-53. Post-April PSIP Plan Maui High Over-Generation Energy Profile: 2030

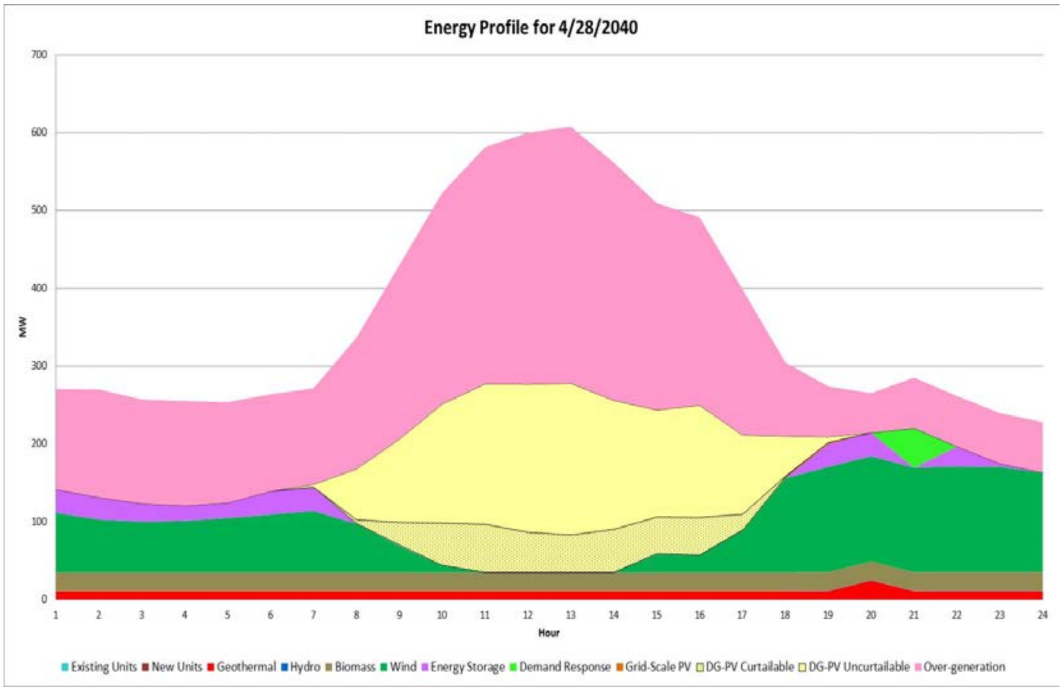

Figure K-54. Post-April PSIP Plan Maui High Over-Generation Energy Profile: 2040

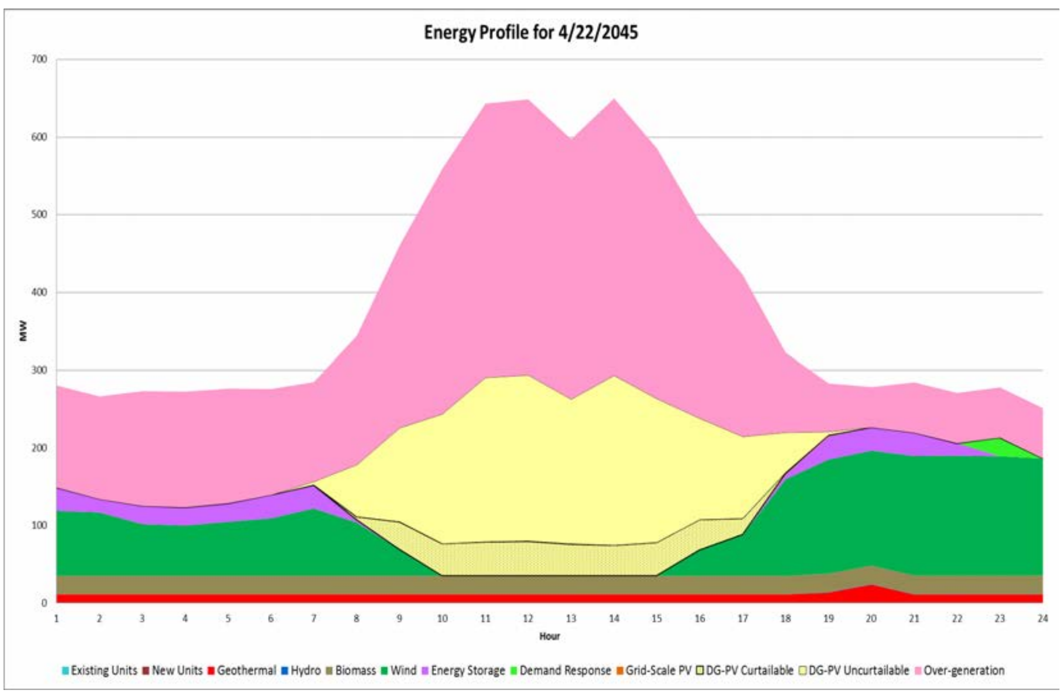

Figure K-55. Post-April PSIP Plan Maui High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for Post-April PSIP Plan

The daily energy profiles for the same years (2020, 2030, 2040, and 2045) for the Post-April PSIP Plan are provided below as a comparison to the E3 plans.

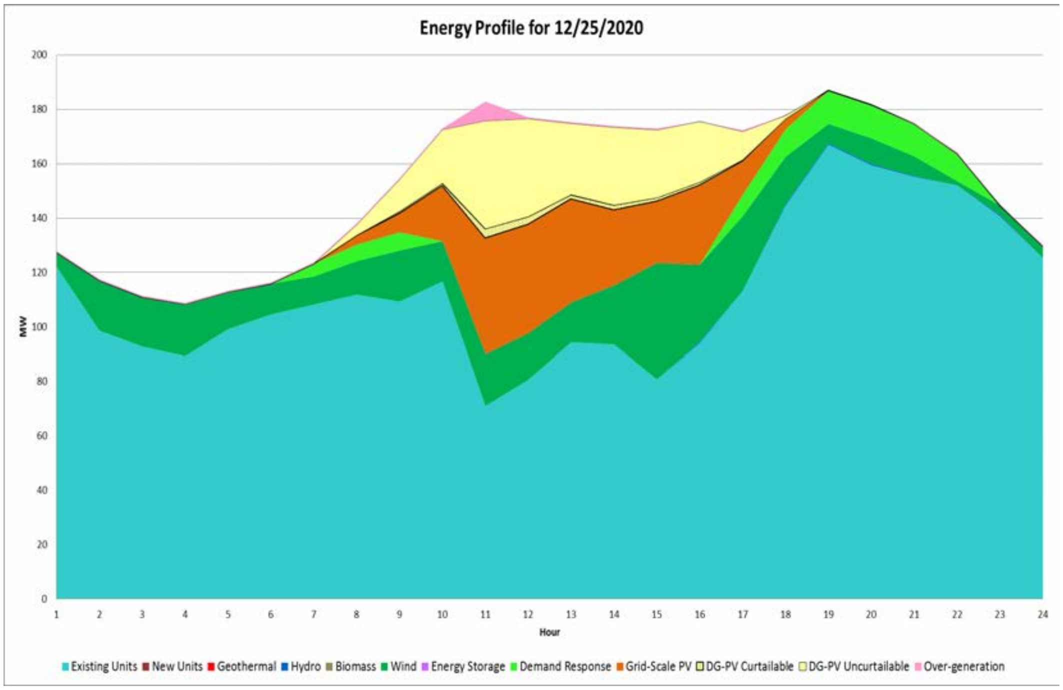

Figure K-56. Post-April PSIP Plan Maui Low Renewables Energy Profile: 2020

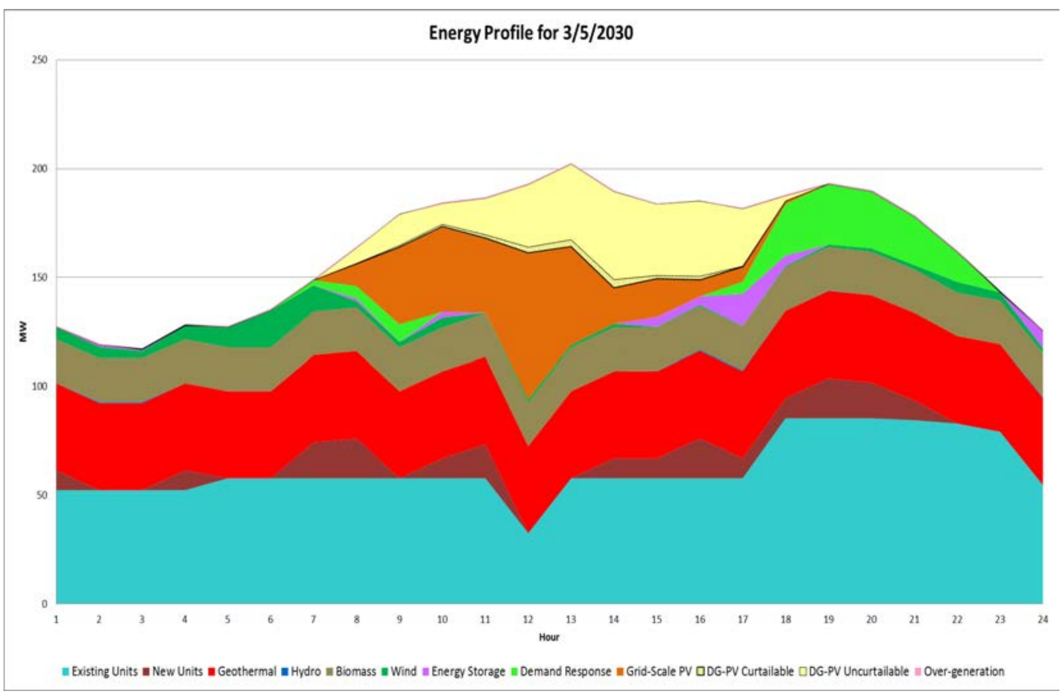

Figure K-57. Post-April PSIP Plan Maui Low Renewables Energy Profile: 2030

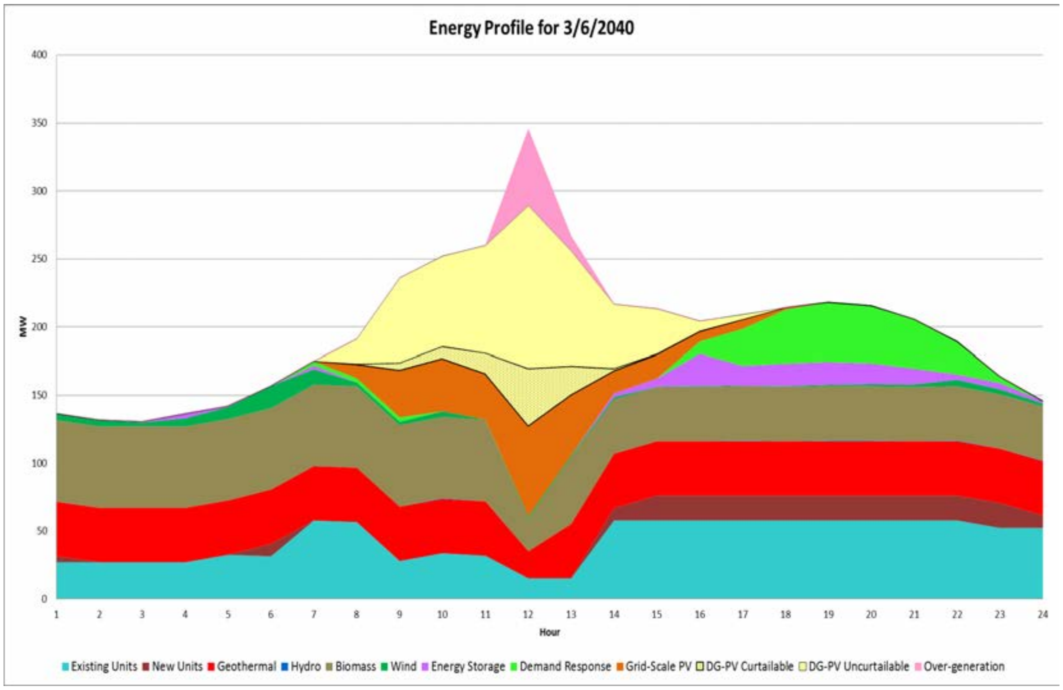

Figure K-58. Post-April PSIP Plan Maui Low Renewables Energy Profile: 2040

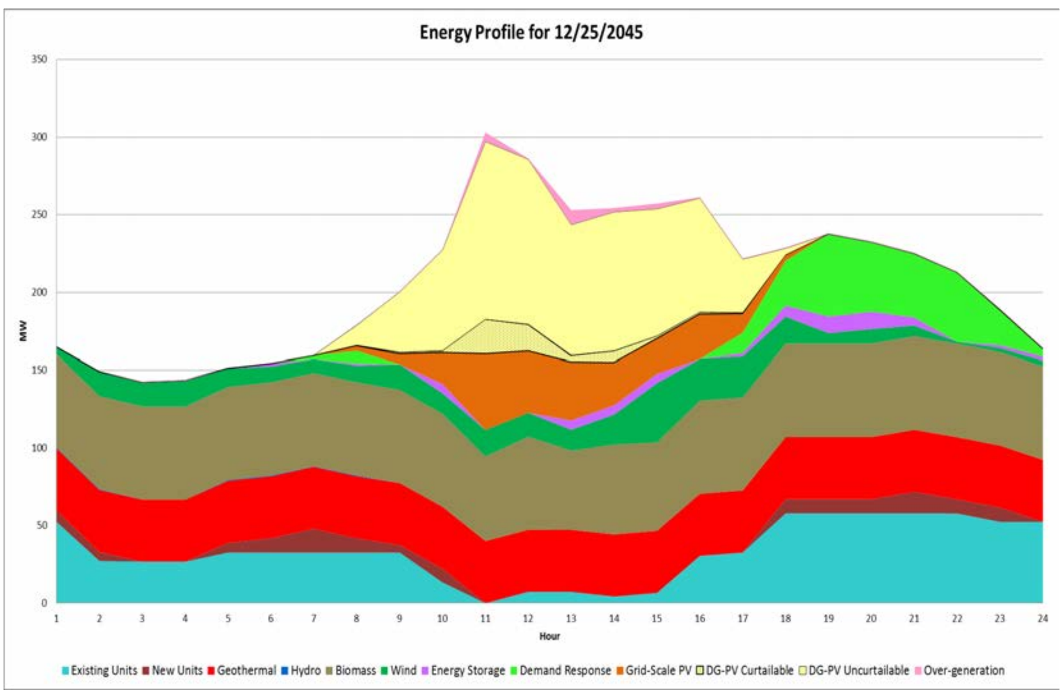

Figure K-59. Post-April PSIP Plan Maui Low Renewables Energy Profile: 2045

MOLOKA'I ANALYTICAL STEPS AND RESULTS

The core cases analyzed for Moloka'i outline different paths to achieving 100% renewable energy in 2020 and 2030.

Energy Mix of Moloka'i Plans

Figure K-60 summarizes the annual RPS for each year.

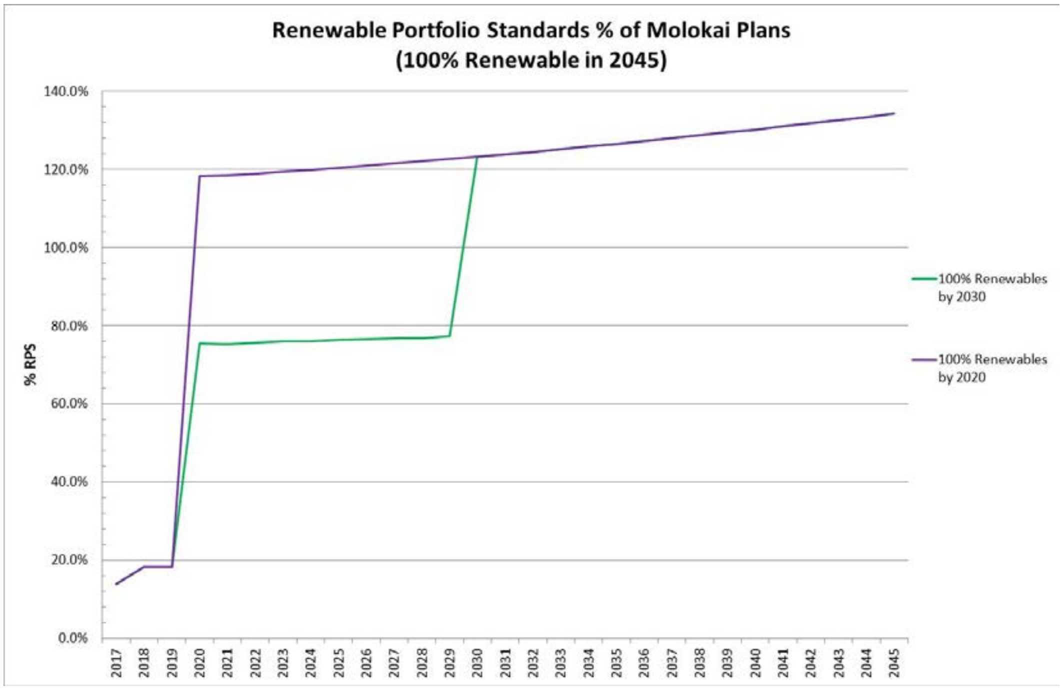

Figure K-60. Renewable Portfolio Standards Percent of Moloka'i Plans

The calculation of the RPS per the law does result in values over 100%. Accelerated targets of 100% renewable energy by 2020 and 100% renewable energy by 2030 are shown in Figure K-61, which includes renewable energy as a percent of total energy including customer-sited generation.

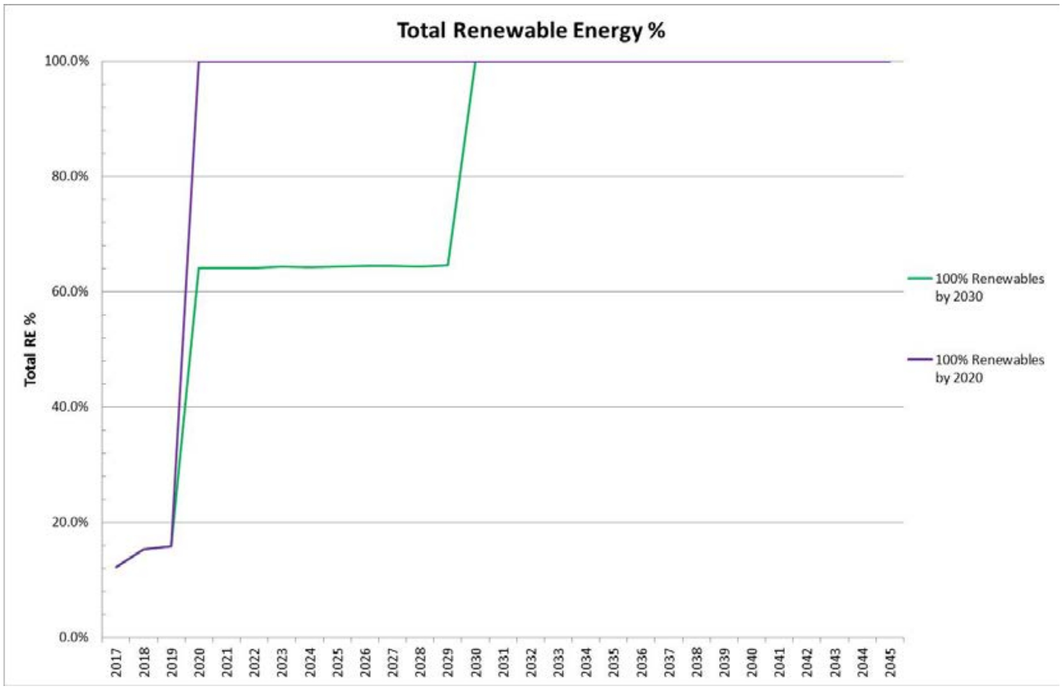

Figure K-61. Total Renewable Energy Percent of Moloka'i Plans

The resource mix for the plans changes over time as it reaches 100% renewable. The figures below reveal how the energy mix in each plan grows to 100% renewable energy.

The annual energy served by resource type is shown in Figure K-62 for the 100% Renewables by 2020 Plan. Although the addition of grid-scale wind in the year 2020 provides a significant amount of energy, there is still a significant amount of biofuel utilized to achieve 100% renewable energy.

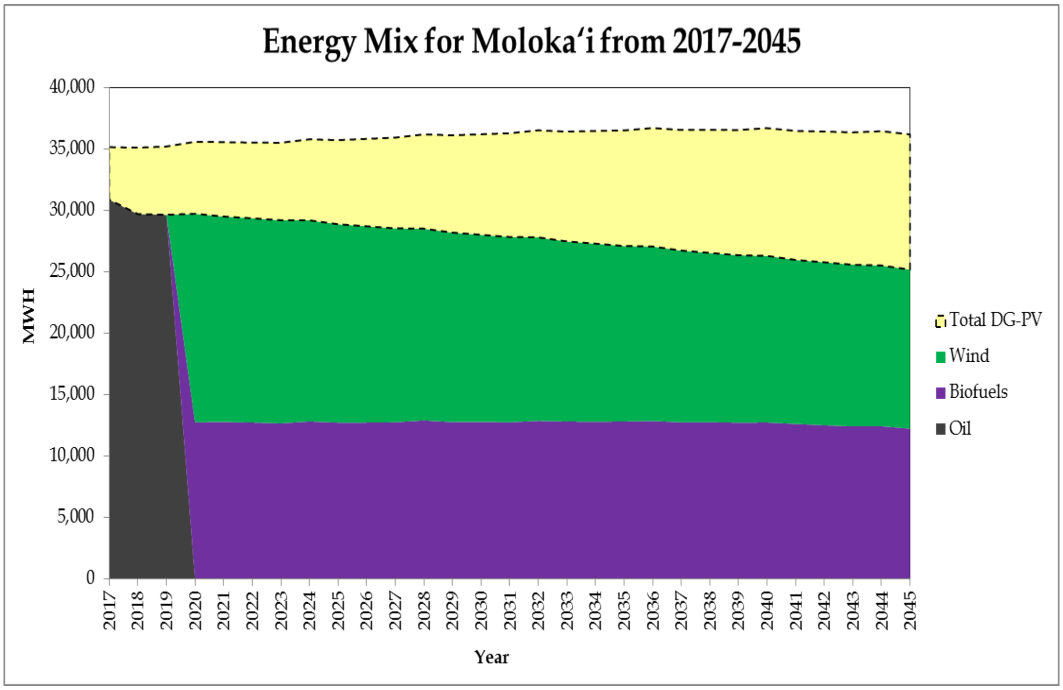

Figure K-62. Energy Mix for 100% Renewables by 2020 Plan on Moloka'i

Figure K-63 shows the energy mix of the 100% Renewables by 2030 Plan.

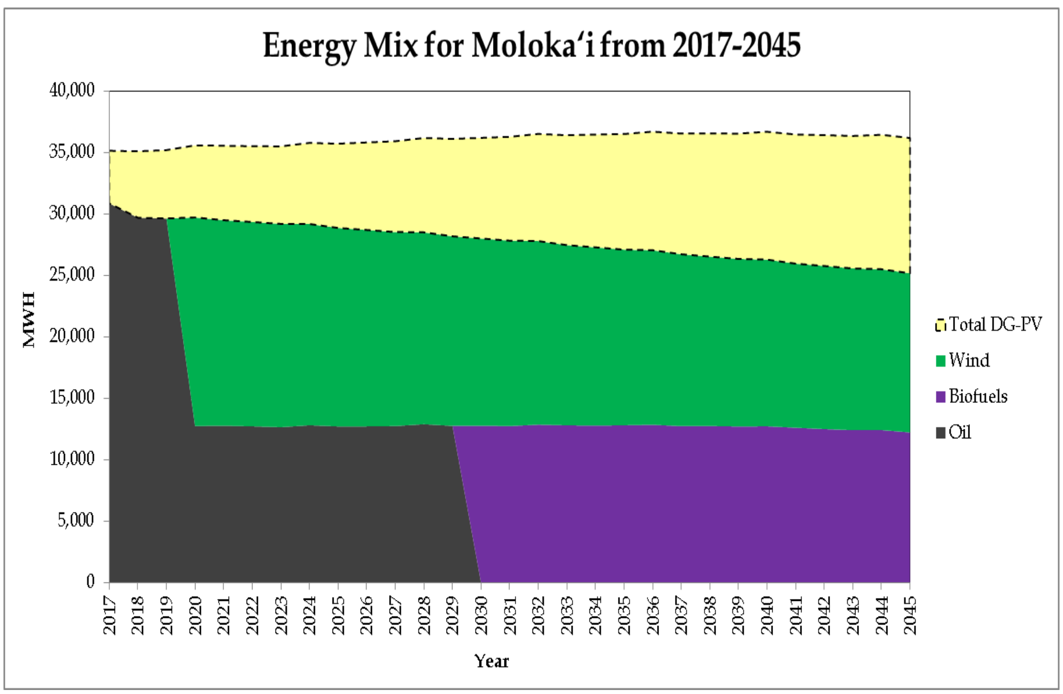

Figure K-63. Energy Mix for 100% Renewables by 2030 Plan on Moloka'i

Percent Over-Generation of Total System for Moloka'i Plans

As increasingly more renewable energy is added to the system, over-generation occurrences will become inevitable. Figure K-64 provides estimates of the percent over-generation of the total system annual energy for the 100% Renewable by 2020 and 100% Renewable by 2030 plans. Both cases add 5 MW of grid-scale wind in 2020 at which time over-generation significantly increases. Both plans have similar annual over-generation since the resource plans are identical. Situations of over-generation provide opportunities, coupled with appropriate controls systems, to allow wind and solar generation to contribute to regulation up resources in addition to use as a reserve resource. This provides improved system performance. In combination, wind and solar used for energy and some level of regulation and reserve appears to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this December 2016 PSIP update (similar to the April 2016 PSIP update), we include the full cost of the grid-scale wind and solar resources in cost calculations, regardless of over-generation levels and provide a simplified accounting for other services from these resources.

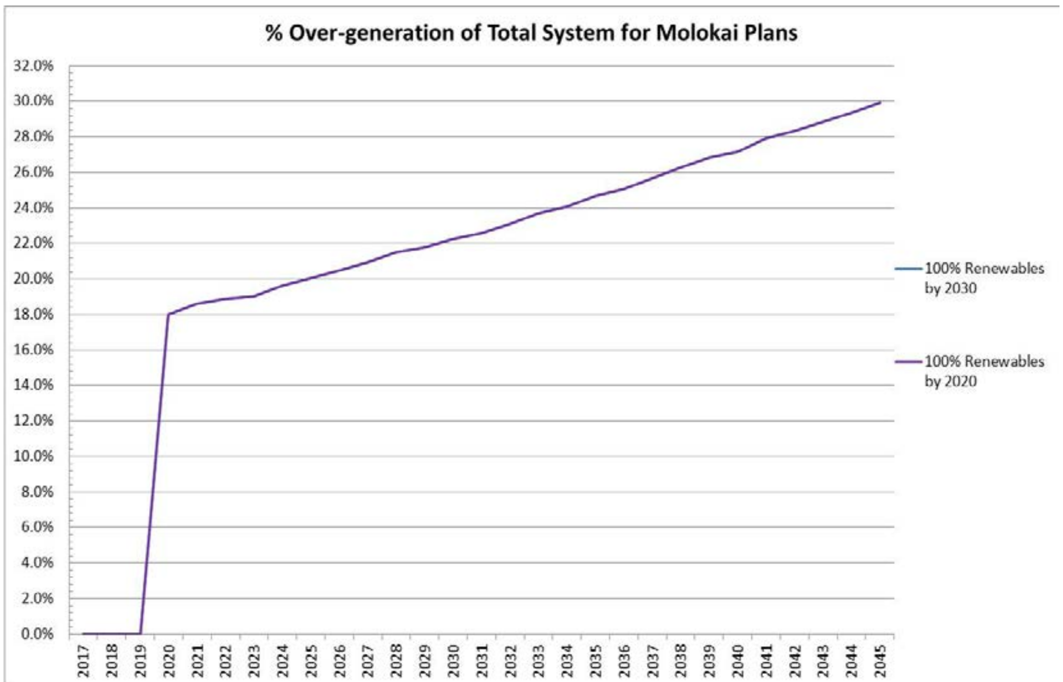

Figure K-64. Total System Over-Generation Percent for Moloka'i Plans

Unserved Energy of Moloka'i Plans

While periods of over-supply exist as described above, periods of unserved energy can also occur. The plans evaluate whether sufficient generation to serve load exists with variable renewable energy and minimal conventional thermal resources on the system. If there was sufficient generation being provided by the remaining thermal resources, variable renewable resources, and storage, then there would not be any unserved energy. The year-by-year amount of unserved energy in hours and energy for the 100% Renewable by 2020 Plan is shown in Figure K-65. For example, in 2020, there are approximately 0.56 kWh total of unserved energy that occurs over the course of two hours in that year.

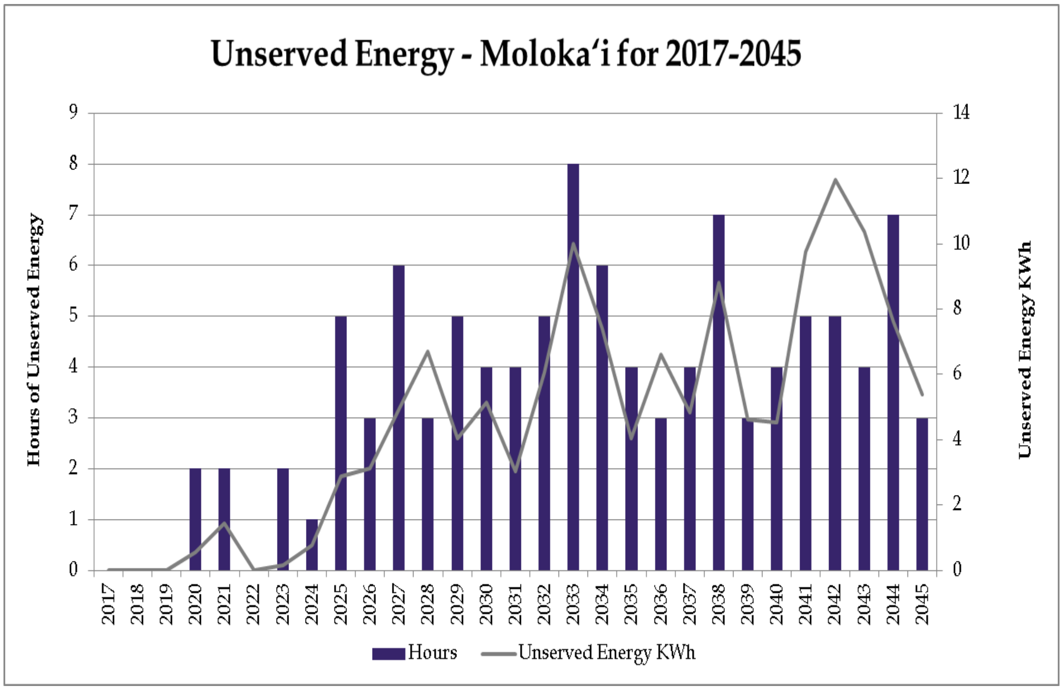

Figure K-65. Unserved Energy for 100% Renewables by 2020 Plan on Moloka'i

The unserved energy for the 100% Renewable by 2030 Plan is similar to the 100% Renewable by 2020 Plan since the resource plans are identical.

Seasonal Variations of Moloka'i Renewable Energy

The resource plans optimized using the PLEXOS model include considerable amounts of grid-scale wind, 5 MW, in 2020 for both the 100% Renewable by 2020 and 100% Renewable by 2030 plans. The seasonality of available grid-scale wind is shown in the figures below.

Figure K-66 shows the difference between the load and the available renewable energy in the year 2025. The difference must be met with thermal generation to prevent unserved energy.

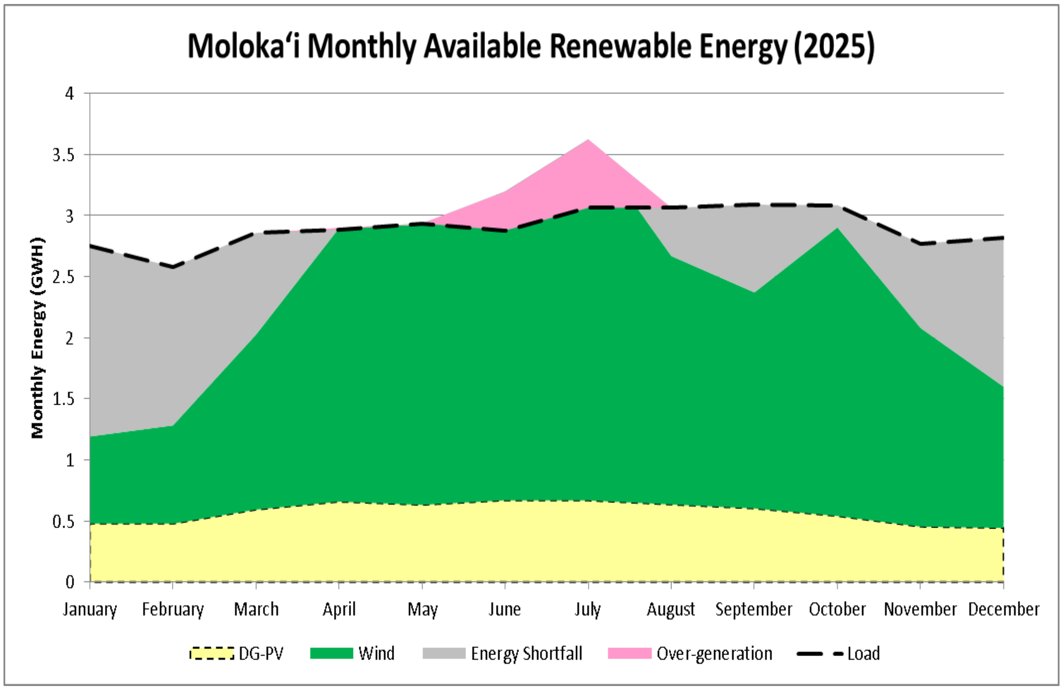

Figure K-66. 100% Renewable by 2020 Plan Monthly Available Renewable Energy vs Load on Moloka'i in 2025

Figure K-67 shows the difference between the load and the available renewable energy in the year 2045. Despite having high amounts of renewable energy available in some months, creating a surplus, shown in pink, there are some months for which there is a deficit, shown in gray. This highlights the continued need for thermal generators to provide supplemental generation during these shortfall periods or energy storage systems, which are capable of shifting energy over several months from the months where there is a surplus to the months where there are shortfall.

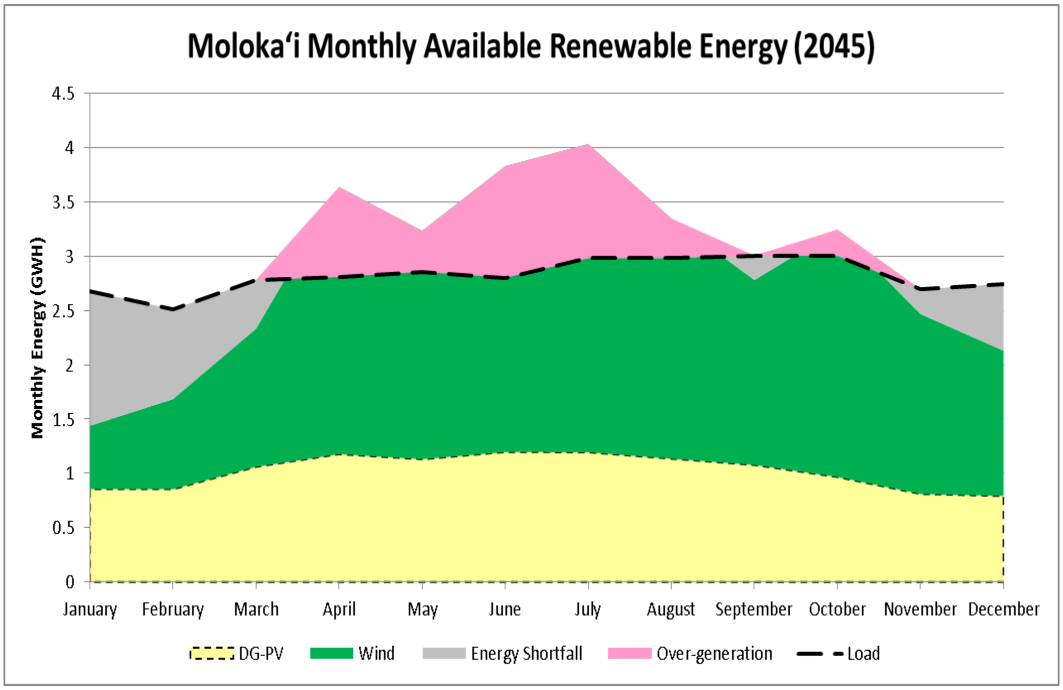

Figure K-67.100% Renewable by 2020 Plan Monthly Available Renewable Energy vs Load on Moloka'i in 2045

Sub-Hourly Charts of Moloka'i Plans

Sub-hourly modeling was performed to analyze the impact that variable renewable energy would have on our system, and whether our portfolio of generators and storage systems would be sufficient to stabilize the electrical grid.

Due to limited data available on Moloka'i, historical minutely renewable energy data from Maui was used to determine the volatility of solar and wind resources on Moloka'i. Historical minutely load data from Moloka'i was used. The volatility of the Auwahi wind farm was applied to future grid-scale wind resources.

An initial screening was done to determine the month with the largest potential minutely downward ramp. PLEXOS was then employed to perform a stochastic analysis on this month. Using the historical minutely data, stochastic variables were created for all as-available resources and the load.

There was virtually no unserved energy in the sub-hourly analysis for Moloka'i in both the 100% Renewable by 2020 and 100% Renewable by 2030 cases when a 1-, 15-, and 30-minute look-ahead was assumed. However, as described in Chapter 4, no regulation requirements were included for the Moloka'i PLEXOS modeling, thus further analysis is needed to determine whether there are sufficient resources to integrate high levels of variable renewable generation on Moloka'i. It should be noted that in actual operations no perfect look ahead is possible, regardless of the time duration.

Daily Energy Charts of Moloka'i Plans

The charts in the previous sections displayed annual and monthly views of how renewable energy is being integrated into the plans and the impacts to the system energy production. This section will convey a more granular view by providing the energy mix for select days of some years of the plans that were modeled.

High Over-Generation Energy Profiles for 100% Renewables by 2020 Plan

Figure K-68 provides a view of the day in the year 2020 that has the highest amount of over-generation for 100% Renewable by 2020 Plan. On this day, there is over-generation in every hour of the day.

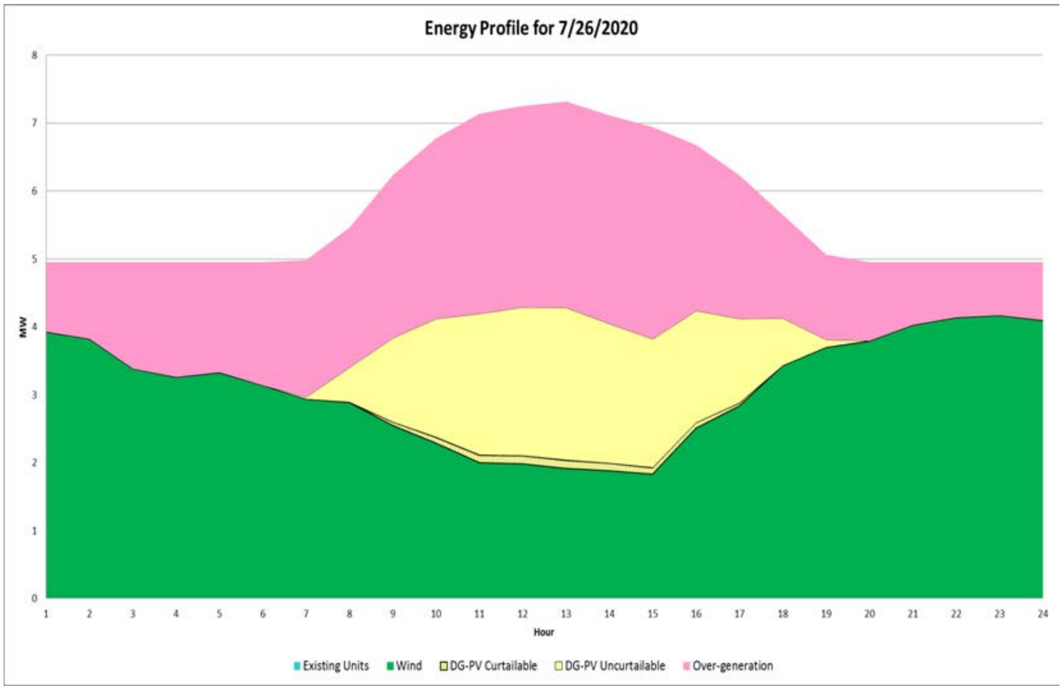

Figure K-68. 100% Renewables by 2020 Plan Moloka'i High Over-Generation Energy Profile: 2020

Figure K-69, Figure K-70, and Figure K-71 show high over-generation days in 2030, 2040, and 2045, respectively. Over-generation increasing over time is illustrated below..

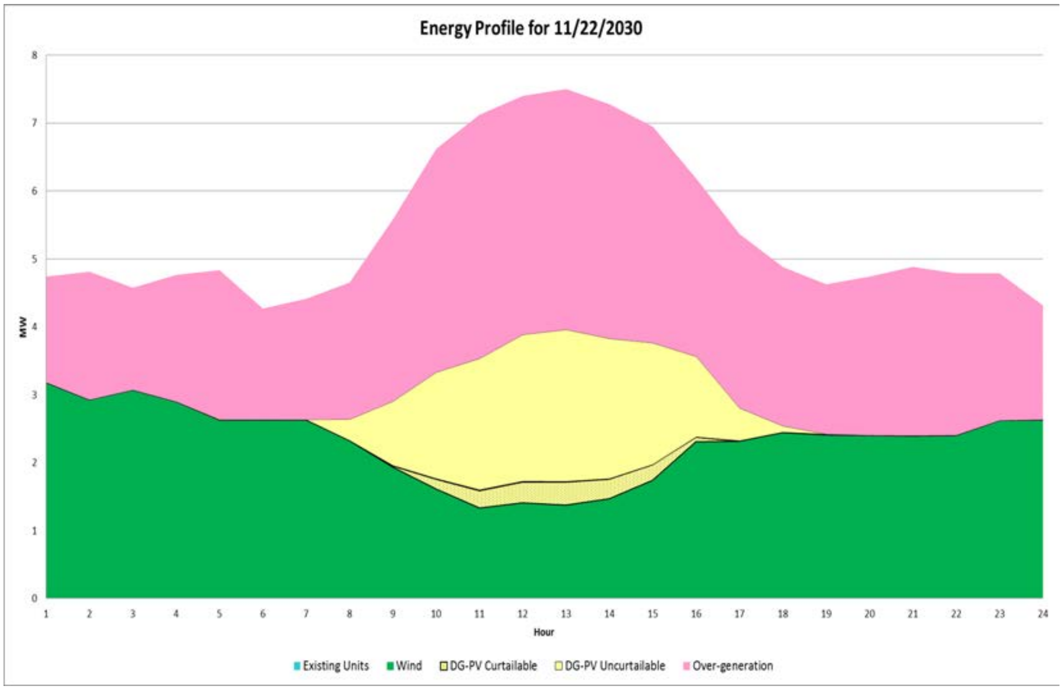

Figure K-69. 100% Renewables by 2020 Plan Moloka'i High Over-Generation Energy Profile: 2030

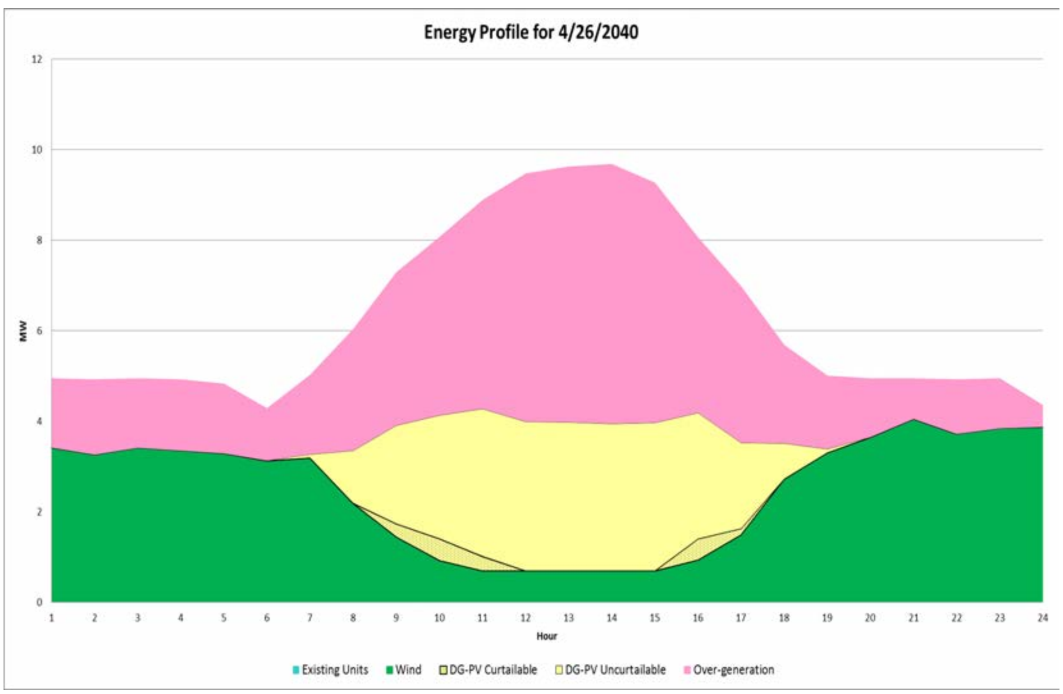

Figure K-70. 100% Renewables by 2020 Plan Moloka'i High Over-Generation Energy Profile: 2040

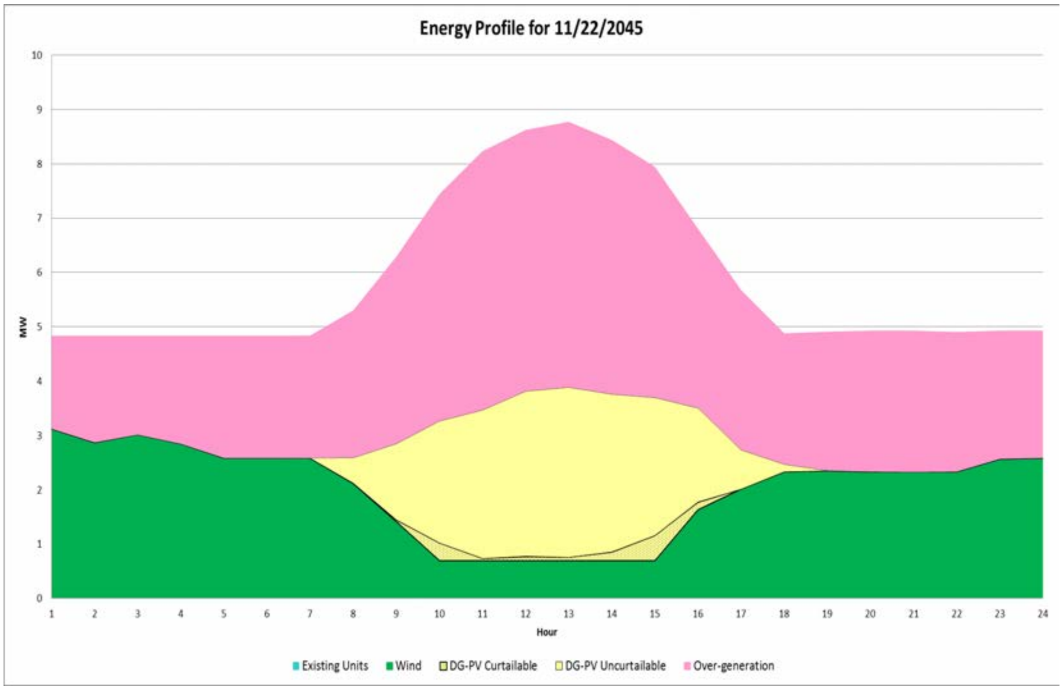

Figure K-71. 100% Renewables by 2020 Plan Moloka'i High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for 100% Renewables by 2020 Plan

Although Hawai'i has abundant renewable resources, such as wind and solar, there are days for which there is limited solar and/or limited or no wind available. Figure K-72, Figure K-73, Figure K-74, and Figure K-75 illustrate how different the energy profile is on days with low renewable energy available in the years 2020, 2030, 2040, and 2045, respectively, for the 100% Renewable by 2020 Plan. Even with the addition of 5 MW of grid-scale wind in 2020, on days where there is low wind availability, thermal generation is still necessary to serve the load.

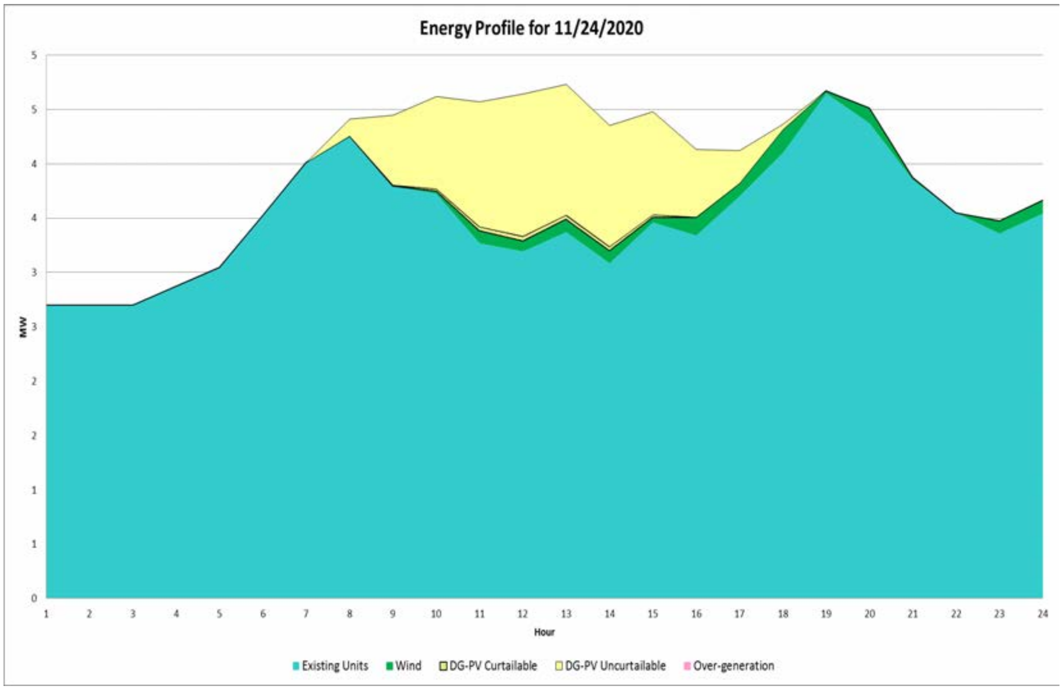

Figure K-72. 100% Renewables by 2020 Plan Moloka'i Low Renewables Energy Profile: 2020

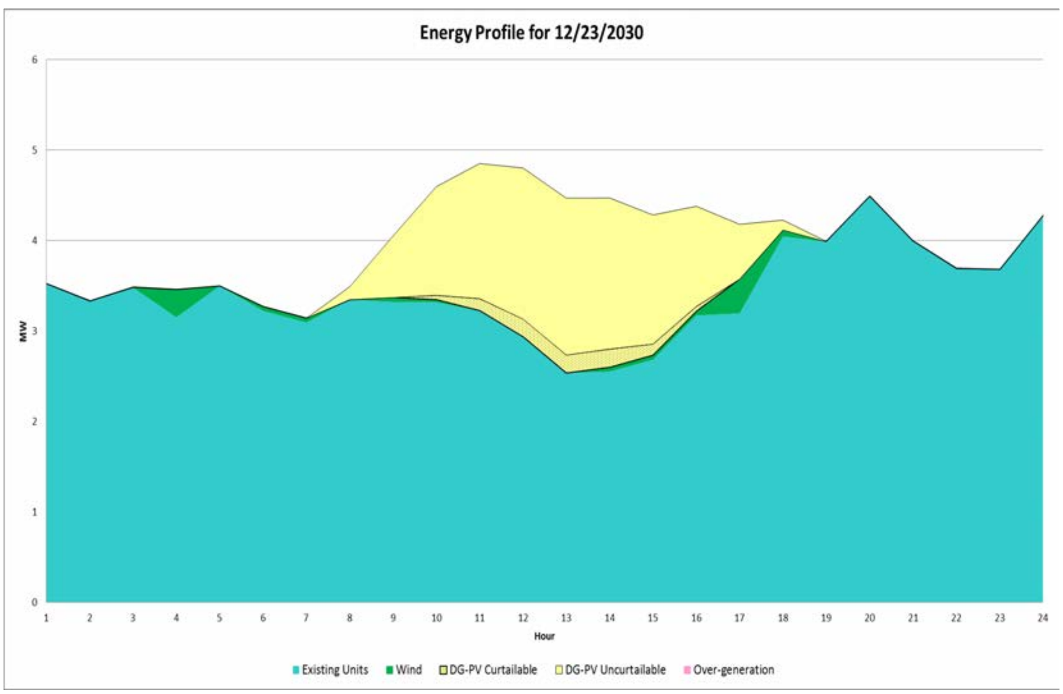

Figure K-73. 100% Renewables by 2020 Plan Moloka'i Low Renewables Energy Profile: 2030

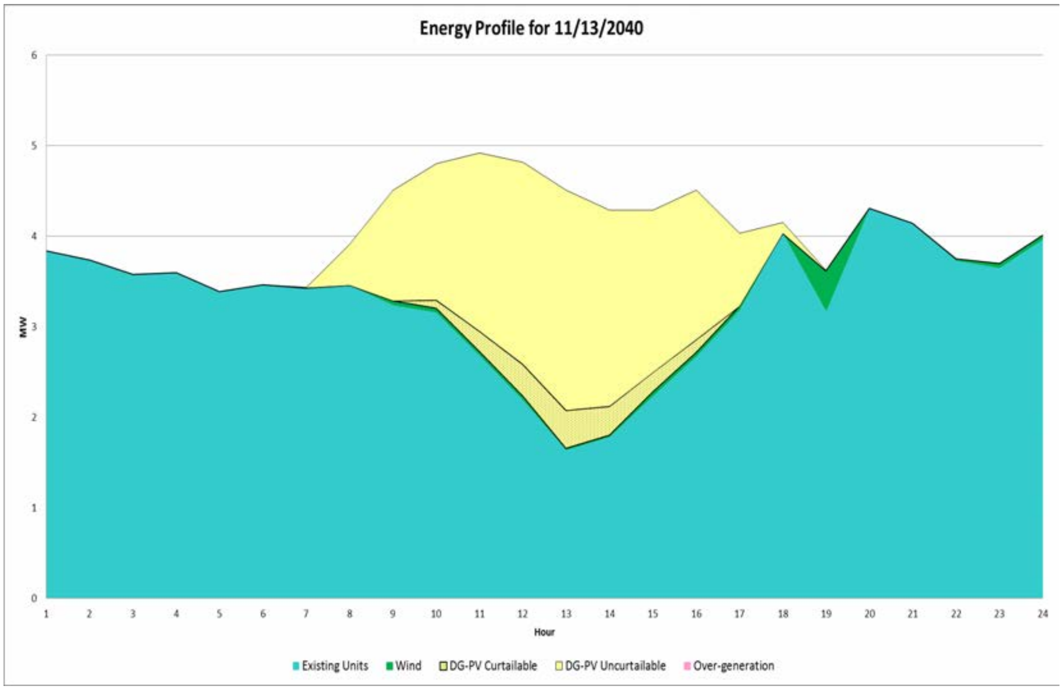

Figure K-74. 100% Renewables by 2020 Plan Moloka'i Low Renewables Energy Profile: 2040

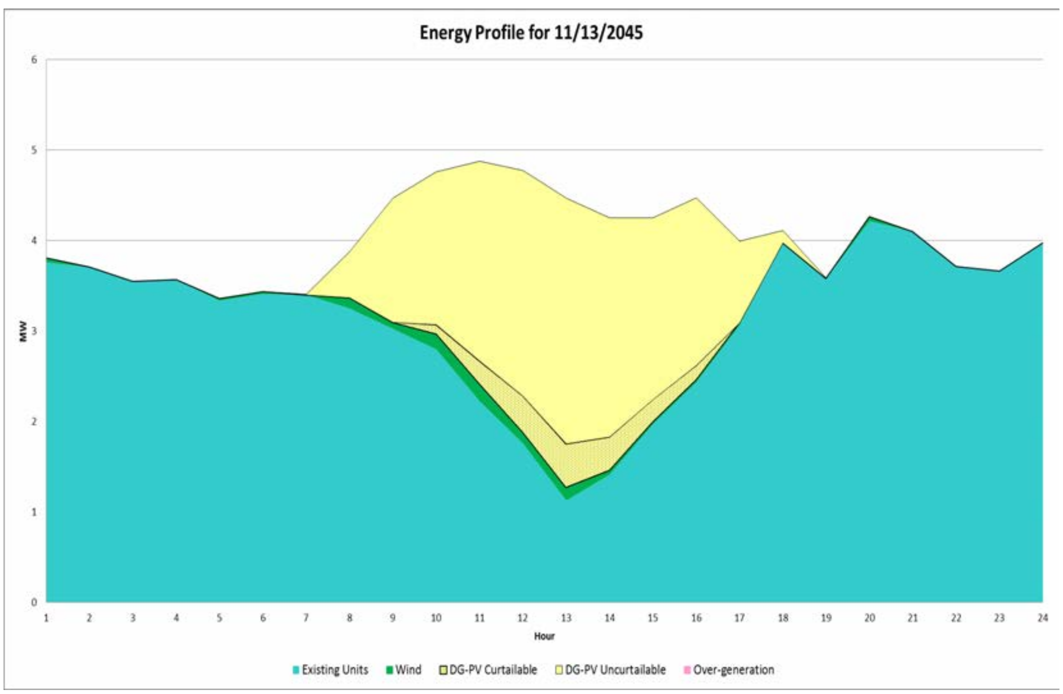

Figure K-75. 100% Renewables by 2020 Plan Moloka'i Low Renewables Energy Profile: 2045

High Over-Generation Energy Profiles for 100% Renewables by 2030 Plan

The daily energy profiles for the 100% Renewable by 2030 Plan are identical to the daily energy profiles provided above for the 100% Renewable by 2020 case as the resource plans are identical.

Low Renewable Energy Profiles for 100% Renewables by 2030 Plan

The daily energy profiles for the 100% Renewable by 2030 Plan are identical to the daily energy profiles provided above for the 100% Renewable by 2020 case as the resource plans are identical.

LANA'I ANALYTICAL STEPS AND RESULTS

The core cases analyzed for Lana'i outline different paths to achieving 100% renewable energy in 2020 and 2030.

Energy Mix of Lana'i Plans

Figure K-76 summarizes the annual RPS for each year.

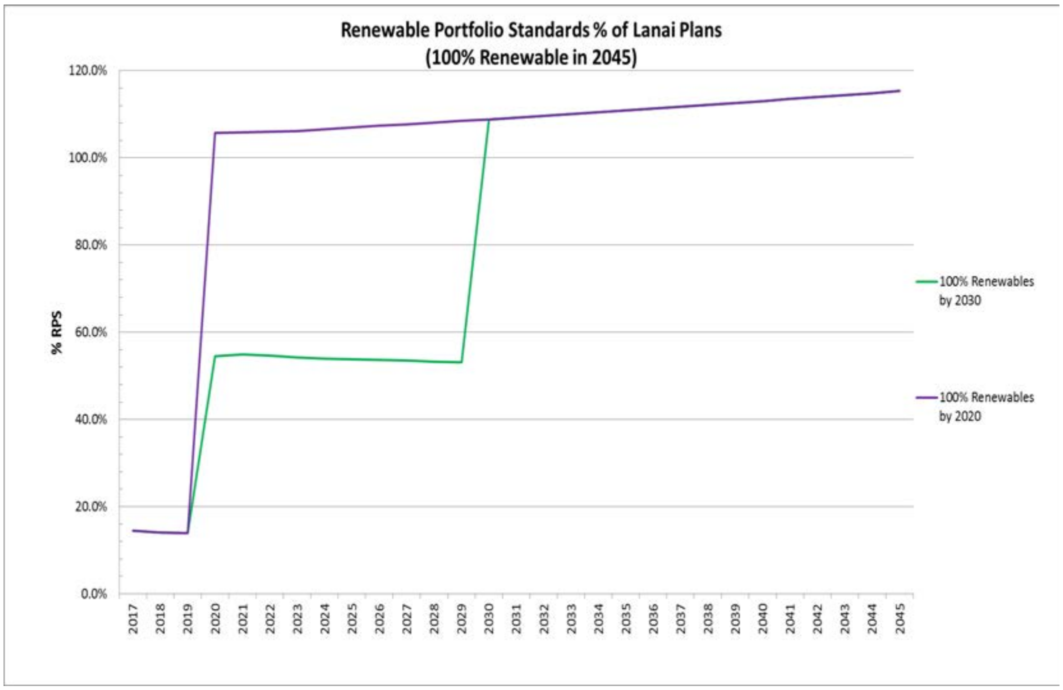

Figure K-76. Renewable Portfolio Standards Percent of Lana'i Plans

The calculation of the RPS per the law does result in values over 100%. Accelerated targets of 100% renewable energy by 2020 and 100% renewable energy by 2030 are shown in Figure K-77, which includes renewable energy as a percent of total energy including customer-sited generation.

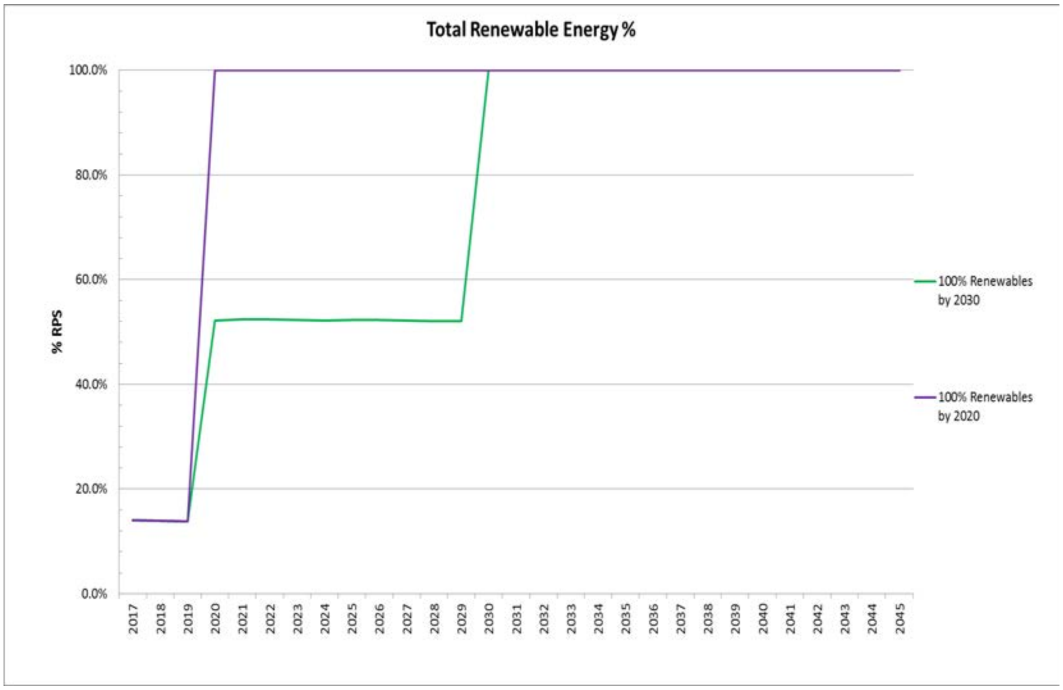

Figure K-77. Total Renewable Energy Percent of Lana'i Plans

The resource mix for the plans changes over time as it reaches 100% renewable. The figures below reveal how the energy mix in each plan grows to 100% renewable energy.

The annual energy served by resource type is shown in Figure K-78 for the 100% Renewables by 2020 Plan. Although the addition of grid-scale wind in the year 2020 provides a significant amount of energy, there is still a significant amount of biofuel utilized to achieve 100% renewable energy.

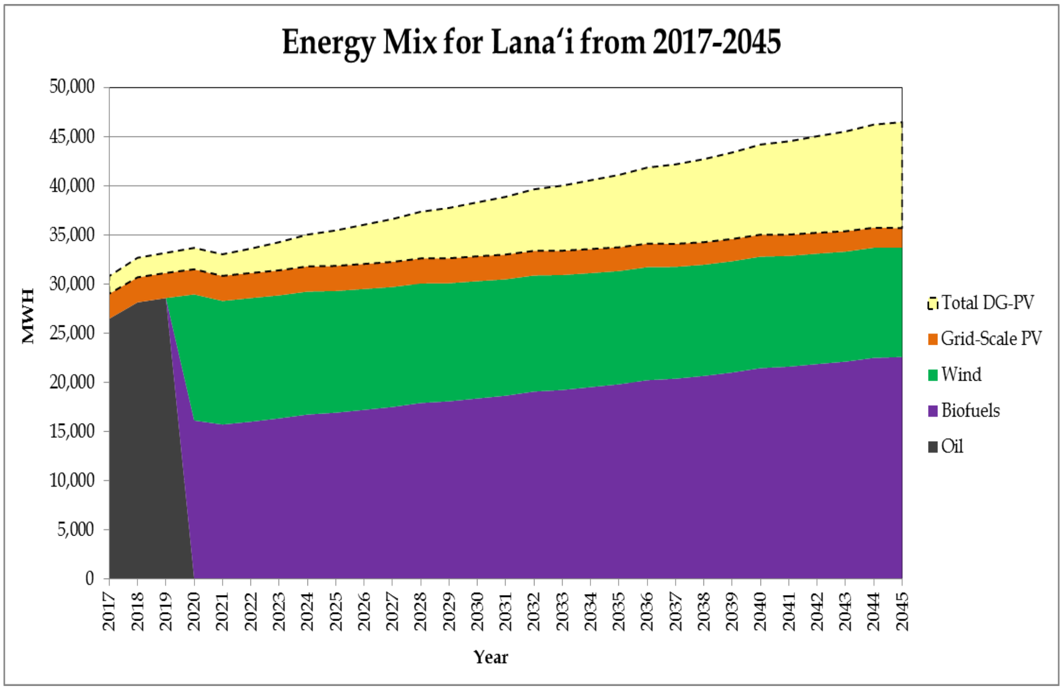

Figure K-78. Energy Mix for 100% Renewables by 2020 Plan on Lana‘i

Figure K-79 shows the energy mix of the 100% Renewables by 2030 Plan.

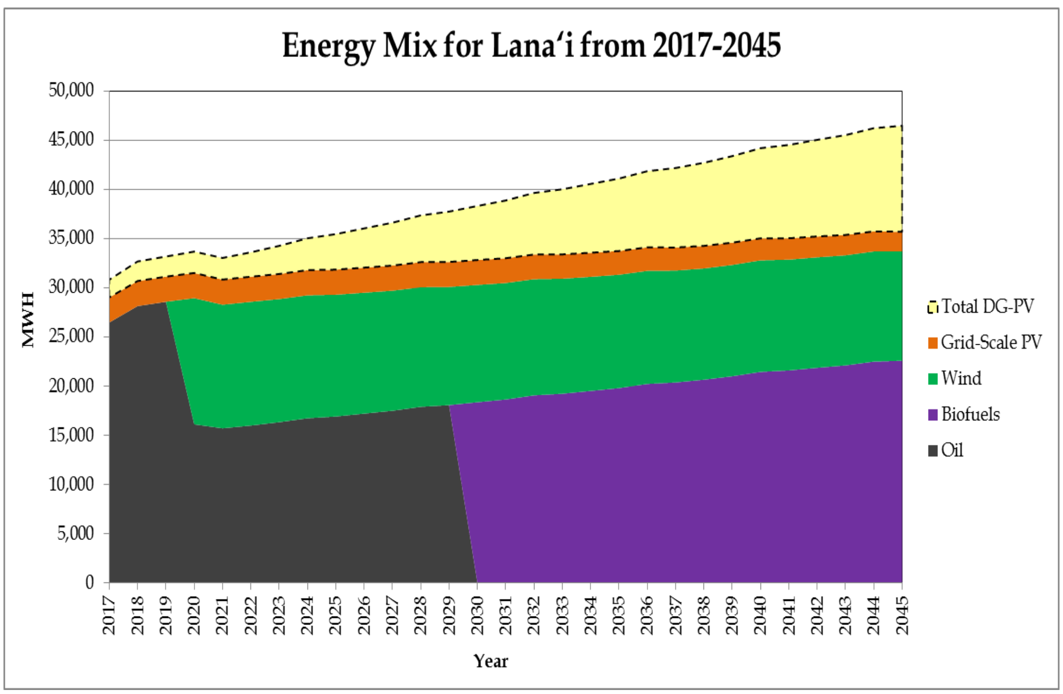

Figure K-79. Energy Mix for 100% Renewables by 2030 Plan on Lana‘i

Percent Over-Generation of Total System for Lana'i Plans

As increasingly more renewable energy is added to the system, over-generation occurrences will become inevitable. Figure K-80 provides estimates of the percent over-generation of the total system annual energy for the 100% Renewable by 2020 and 100% Renewable by 2030 plans. Both cases add 4 MW of grid-scale wind in 2020 at which time over-generation significantly increases. Both plans have similar annual over-generation since the resource plans are identical. Situations of over-generation provide opportunities, coupled with appropriate controls systems, to allow wind and solar generation to contribute to regulation up resources in addition to use as a reserve resource. This provides improved system performance. In combination, wind and solar used for energy and some level of regulation and reserve appears to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this December 2016 PSIP update (similar to the April 2016 PSIP update), we include the full cost of the grid-scale wind and solar resources in cost calculations, regardless of over-generation levels and provide a simplified accounting for other services from these resources.

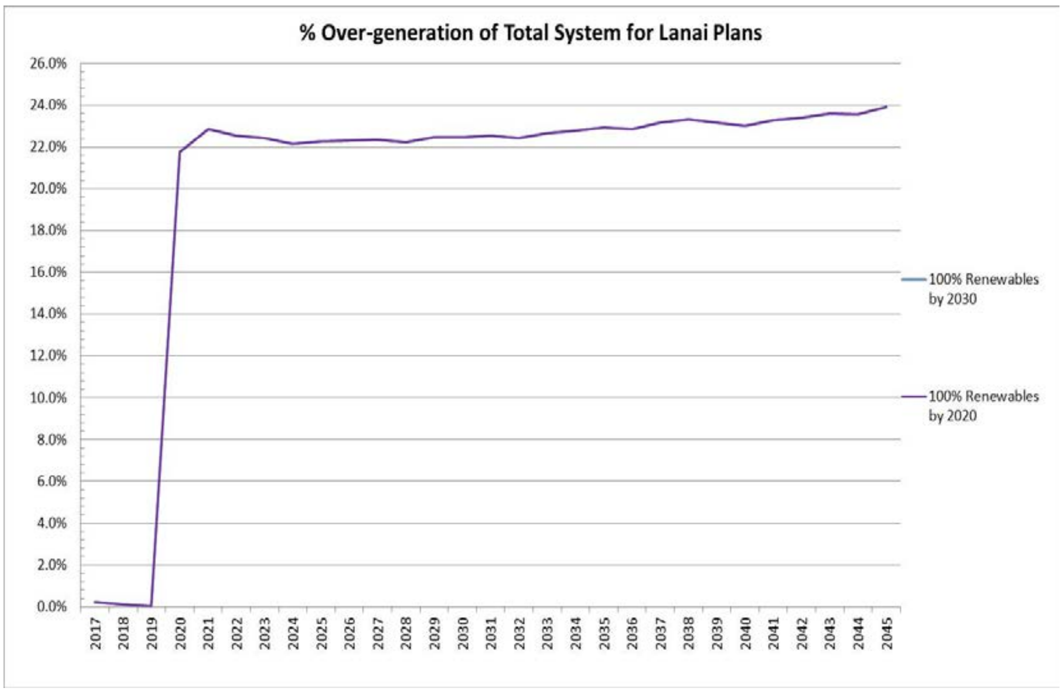

Figure K-80. Total System Over-Generation Percent for Lana'i Plans

Unserved Energy of Lana'i Plans

While periods of over-supply exist as described above, periods of unserved energy can also occur. The plans evaluate whether sufficient generation to serve load exists with variable renewable energy and minimal conventional thermal resources on the system. If there was sufficient generation being provided by the remaining thermal resources, variable renewable resources, and storage, then there would not be any unserved energy. The year-by-year amount of unserved energy in hours and energy for the 100% Renewable by 2020 Plan is shown in Figure K-81. For example, in 2020, there are approximately 3.8 kWh total of unserved energy that occurs over the course of two hours in that year.

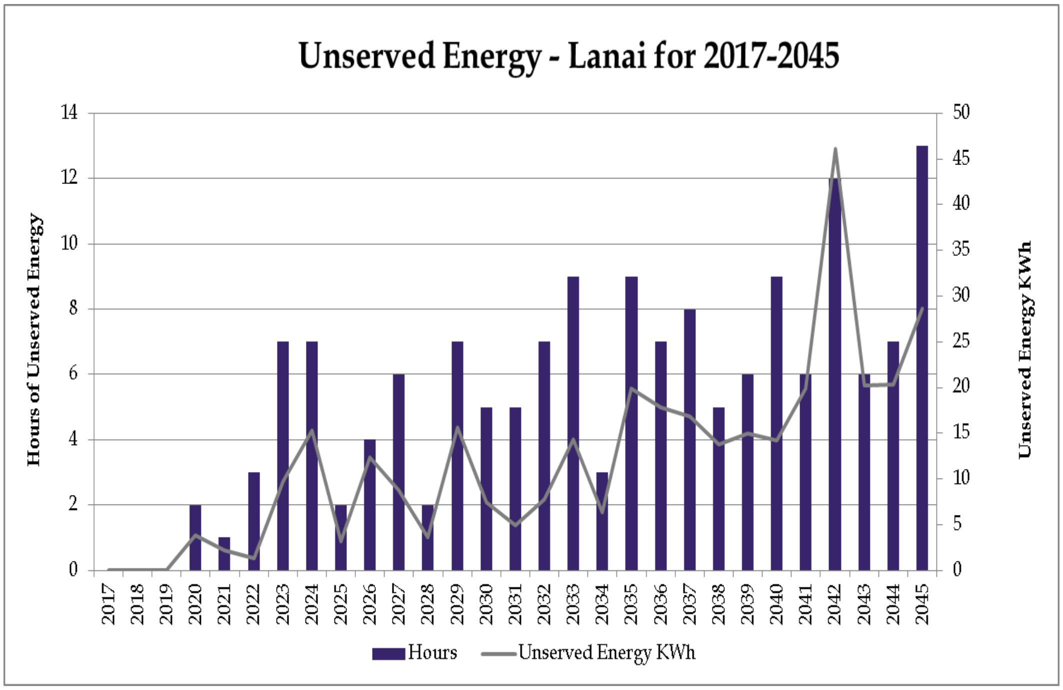

Figure K-81. Unserved Energy for 100% Renewables by 2020 Plan on Lana'i

The unserved energy for the 100% Renewable by 2030 Plan is similar to the 100% Renewable by 2020 Plan since the resource plans are identical.

Seasonal Variations of Lana'i Renewable Energy

The resource plans optimized using the PLEXOS model include considerable amounts of grid-scale wind, 4 MW, in 2020 for both the 100% Renewable by 2020 and 100% Renewable by 2030 plans. The seasonality of available grid-scale wind is shown in the figures below.

Figure K-82 shows the difference between the load and the available renewable energy in the year 2025. The difference must be met with thermal generation to prevent unserved energy.

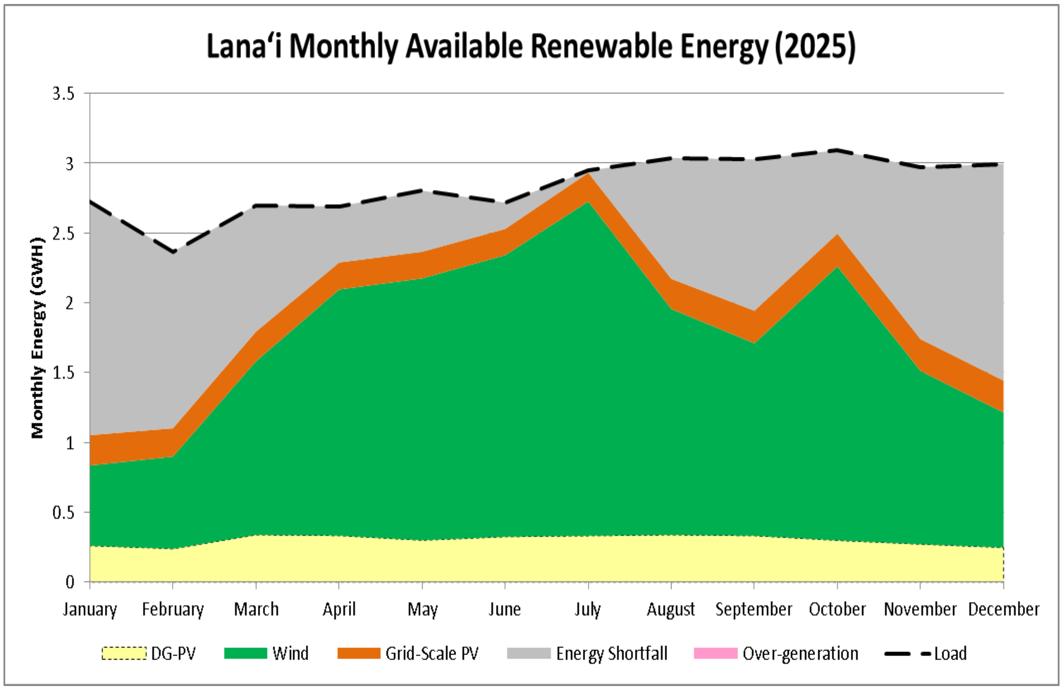

Figure K-82.100% Renewable by 2020 Plan Monthly Available Renewable Energy vs Load on Lana'i in 2025

Figure K-83 shows the difference between the load and the available renewable energy in the year 2045. Despite having high amounts of renewable energy available in some months, creating a surplus, shown in pink, there are some months for which there is a deficit, shown in gray. This highlights the continued need for thermal generators to provide supplemental generation during these shortfall periods or energy storage systems, which are capable of shifting energy over several months from the months where there is a surplus to the months where there are shortfall.

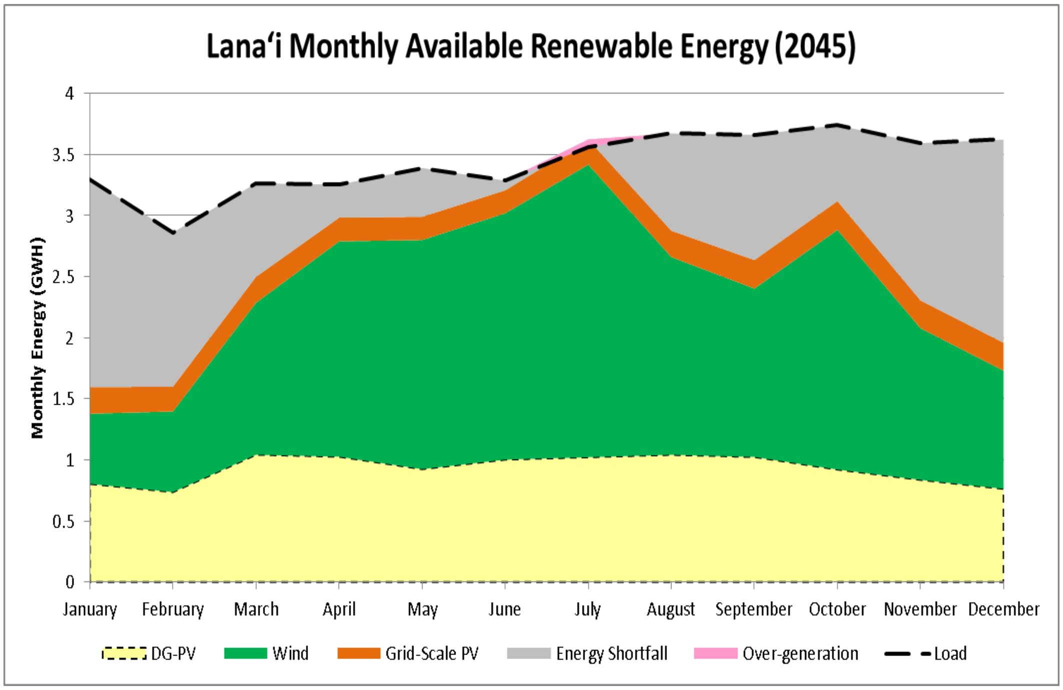

Figure K-83. 100% Renewable by 2020 Plan Monthly Available Renewable Energy vs Load on Lana'i in 2045

Sub-Hourly Charts of Lana'i Plans

Sub-hourly modeling was performed to analyze the impact that variable renewable energy would have on our system, and whether our portfolio of generators and storage systems would be sufficient to stabilize the electrical grid.

Due to limited data available on Lana'i, historical minutely renewable energy data from Maui was used to determine the volatility of solar and wind resources on Lana'i. Historical minutely load data from Lana'i was also used. The volatility of the Auwahi wind farm was applied to future grid-scale wind resources.

An initial screening was done to determine the month with the largest potential minutely downward ramp. PLEXOS was then employed to perform a stochastic analysis on this month. Using the historical minutely data, stochastic variables were created for all as-available resources and the load.

There was virtually no unserved energy in the sub-hourly analysis for Lana'i in both the 100% Renewable by 2020 and 100% Renewable by 2030 cases when a 1-, 15-, and 30-minute look-ahead was assumed. However, as described in Chapter 4, no regulation requirements were included for the Lana'i PLEXOS modeling, thus further analysis is needed to determine whether there are sufficient resources to integrate high levels of variable renewable generation on Lana'i. It should be noted that in actual operations no perfect look ahead is possible, regardless of the time duration

Daily Energy Charts of Lana'i Plans

The charts in the previous sections displayed annual and monthly views of how renewable energy is being integrated into the plans and the impacts to the system energy production. This section will convey a more granular view by providing the energy mix for select days of some years of the plans that were modeled.

High Over-Generation Energy Profiles for 100% Renewables by 2020 Plan

Figure K-84 provides a view of the day in the year 2020 that has the highest amount of over-generation for 100% Renewable by 2020 Plan. On this day, there is over-generation in every hour of the day.

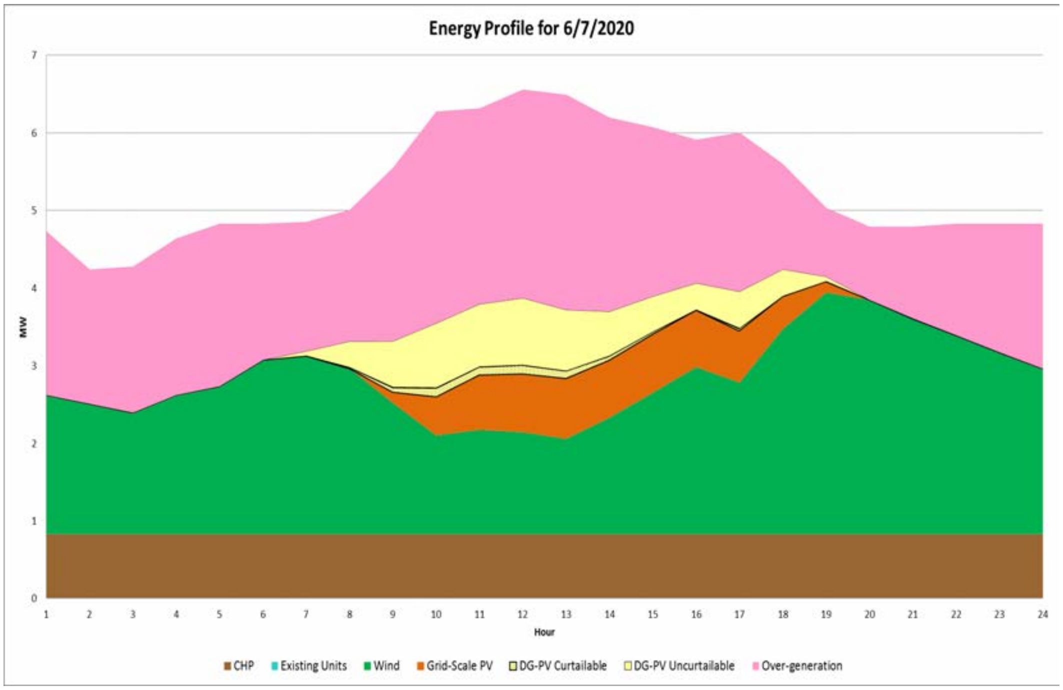

Figure K-84. 100% Renewables by 2020 Plan Lana'i High Over-Generation Energy Profile: 2020

Figure K-85, Figure K-86, and Figure K-87 show high over-generation days in 2030, 2040, and 2045, respectively. Over-generation increasing over time is illustrated below.

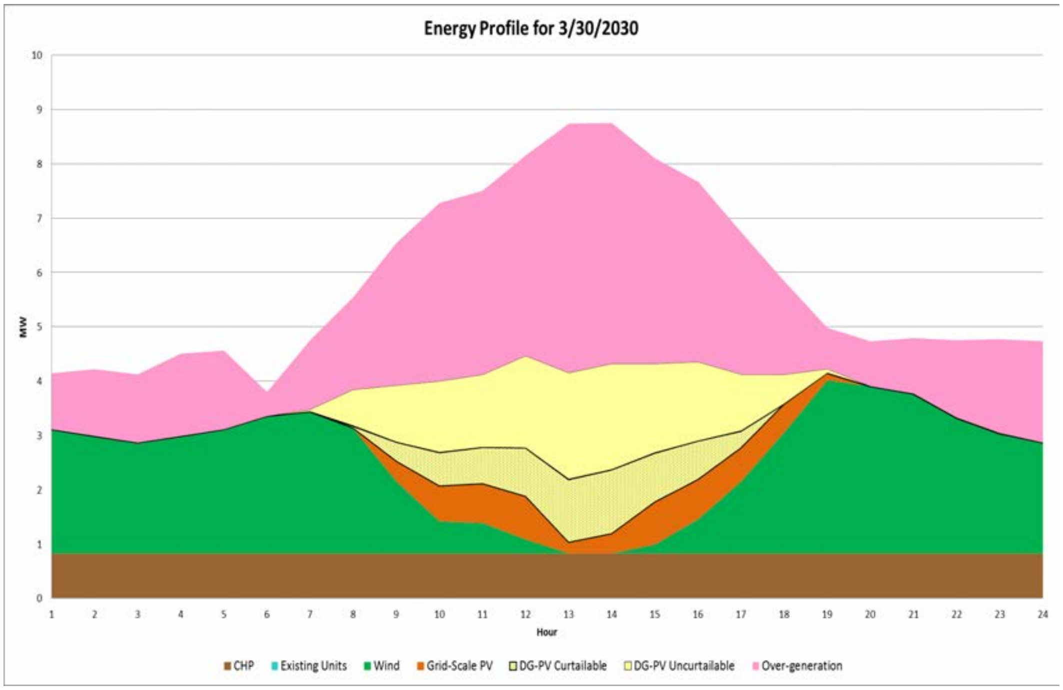

Figure K-85. 100% Renewables by 2020 Plan Lana'i High Over-Generation Energy Profile: 2030

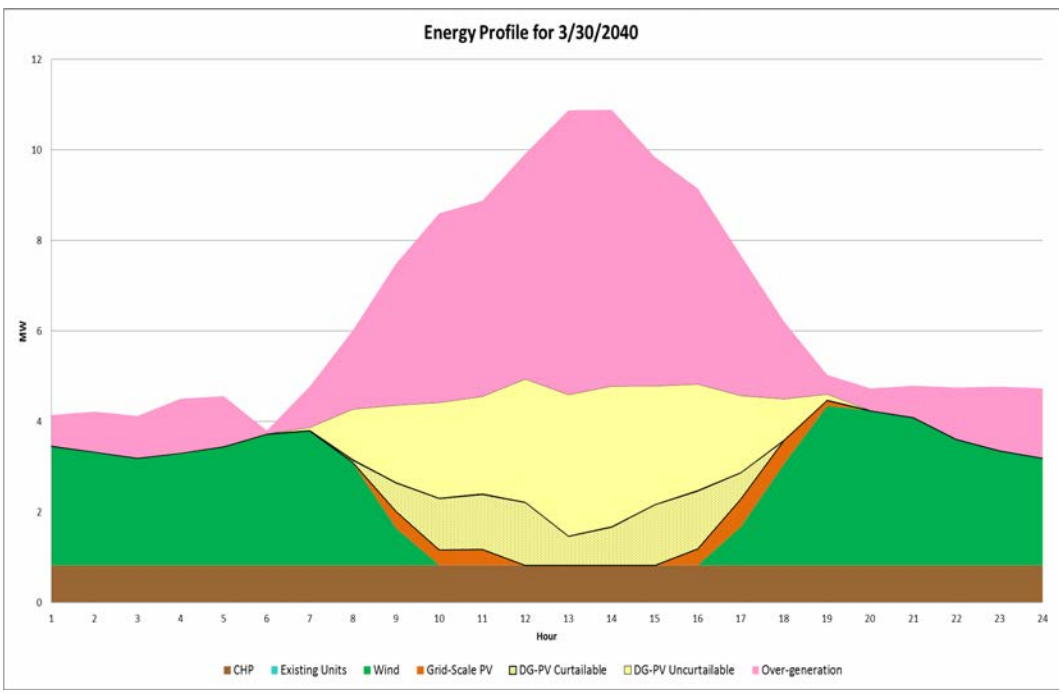

Figure K-86. 100% Renewables by 2020 Plan Lana'i High Over-Generation Energy Profile: 2040

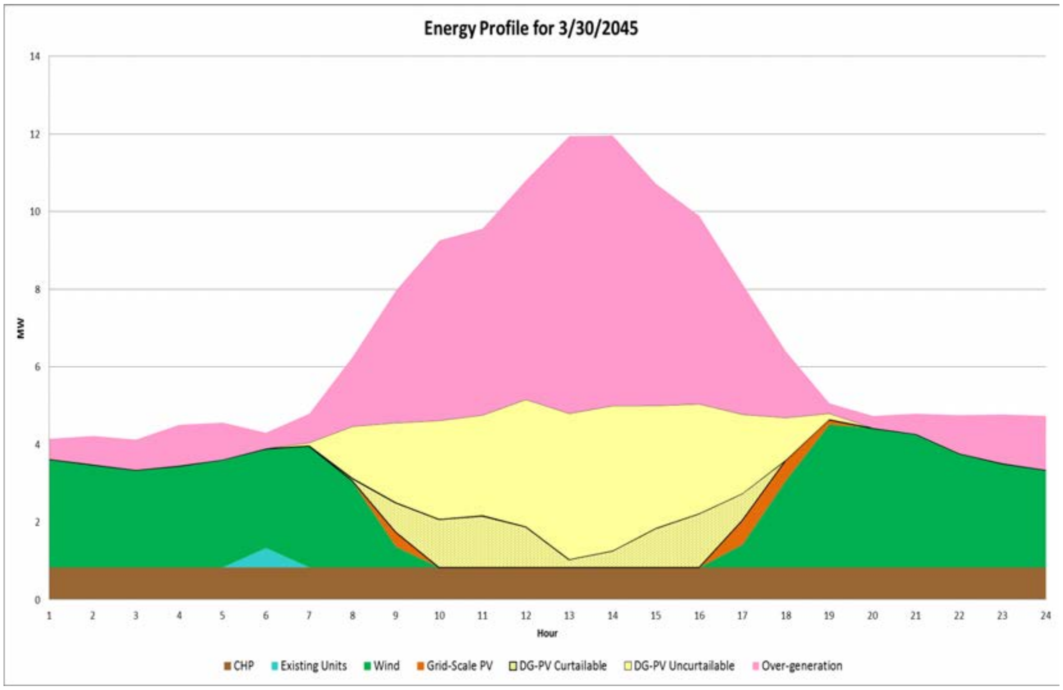

Figure K-87. 100% Renewables by 2020 Plan Lana'i High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for 100% Renewables by 2020 Plan

Although Hawai'i has abundant renewable resources, such as wind and solar, there are days for which there is limited solar and/or limited or no wind available. Figure K-88, Figure K-89, Figure K-90, and Figure K-91 illustrate how different the energy profile is on days with low renewable energy available in the years 2020, 2030, 2040, and 2045, respectively, for the 100% Renewable by 2020 Plan. Even with the addition of 4 MW of grid-scale wind in 2020, on days where there is low wind availability, thermal generation is still necessary to serve the load.

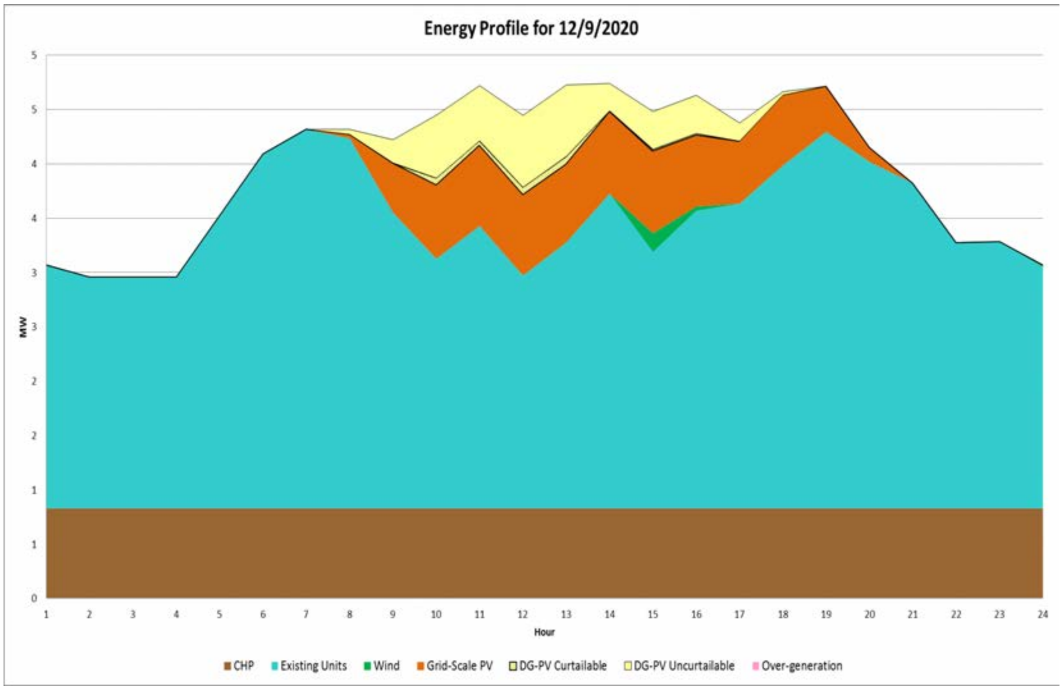

Figure K-88. 100% Renewables by 2020 Plan Lana'i Low Renewables Energy Profile: 2020

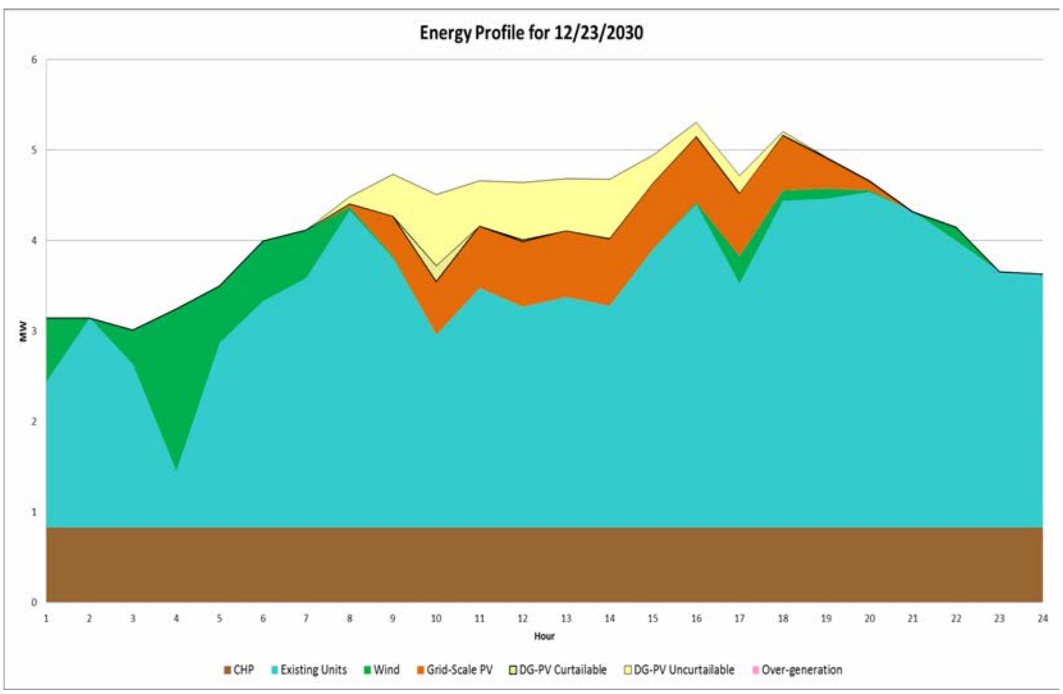

Figure K-89. 100% Renewables by 2020 Plan Lana'i Low Renewables Energy Profile: 2030

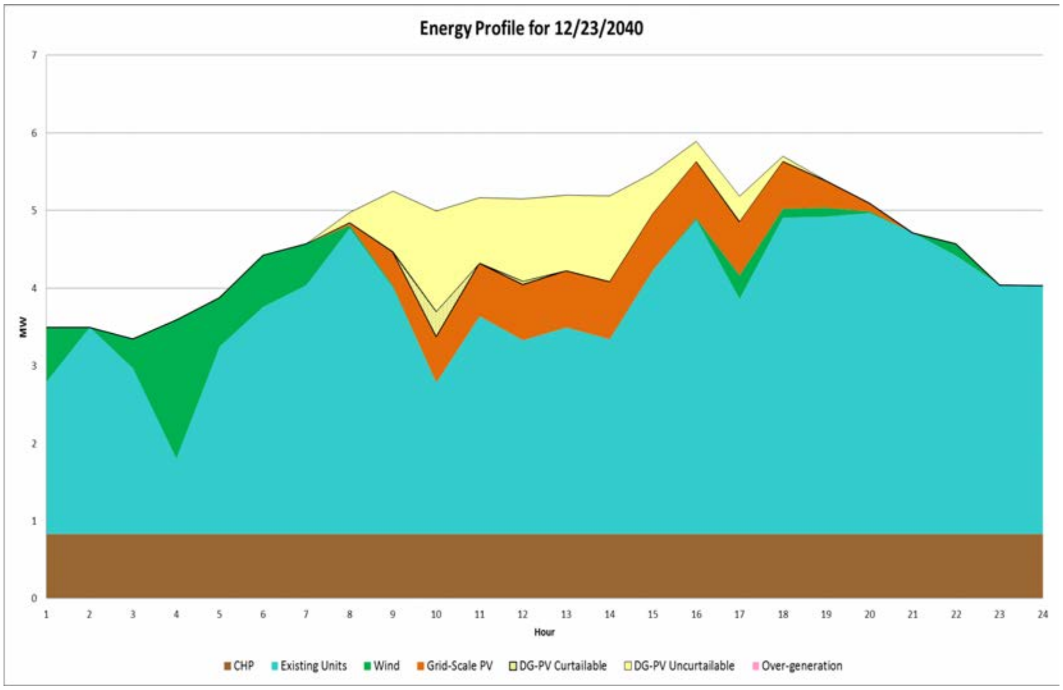

Figure K-90. 100% Renewables by 2020 Plan Lana'i Low Renewables Energy Profile: 2040

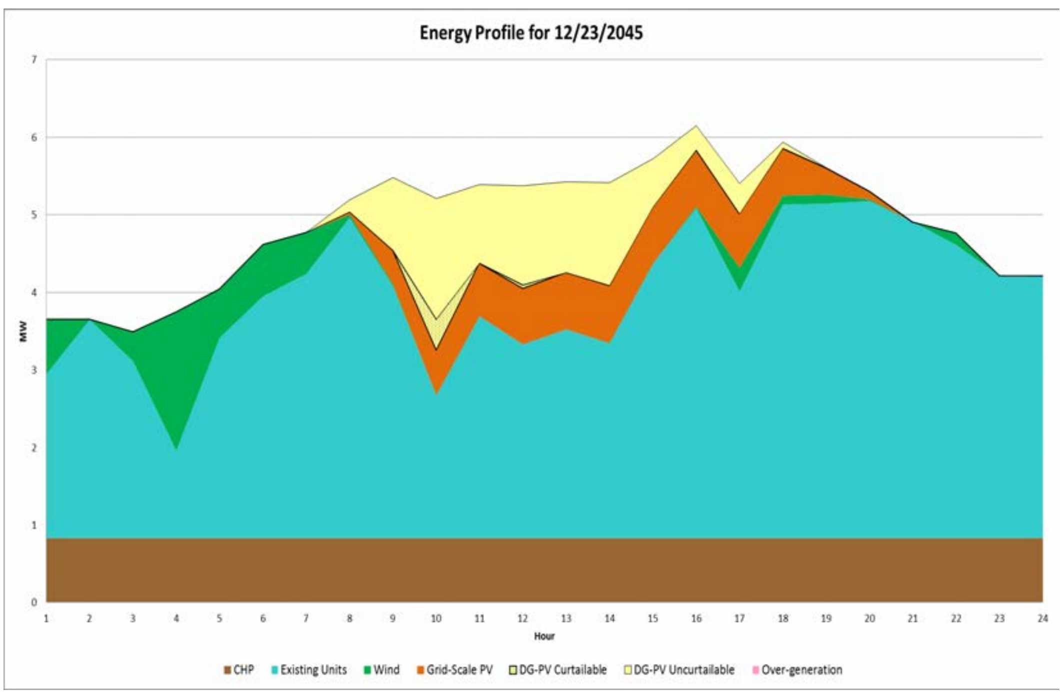

Figure K-91. 100% Renewables by 2020 Plan Lana'i Low Renewables Energy Profile: 2045

High Over-Generation Energy Profiles for 100% Renewables by 2030 Plan

The daily energy profiles for the 100% Renewable by 2030 Plan are identical to the daily energy profiles provided above for the 100% Renewable by 2020 case as the resource plans are identical.

Low Renewable Energy Profiles for 100% Renewables by 2030 Plan

The daily energy profiles for the 100% Renewable by 2030 Plan are identical to the daily energy profiles provided above for the 100% Renewable by 2020 case as the resource plans are identical.

HAWAI'I ISLAND ANALYTICAL STEPS AND RESULTS

The core cases analyzed for Hawai'i Island outline different paths to achieving 100% renewable energy in 2045 as well as an accelerated target of 2040 consistent with the April 2016 PSIP.

Energy Mix of Hawai'i Island Plans

Figure K-92 summarizes the annual RPS for each year.

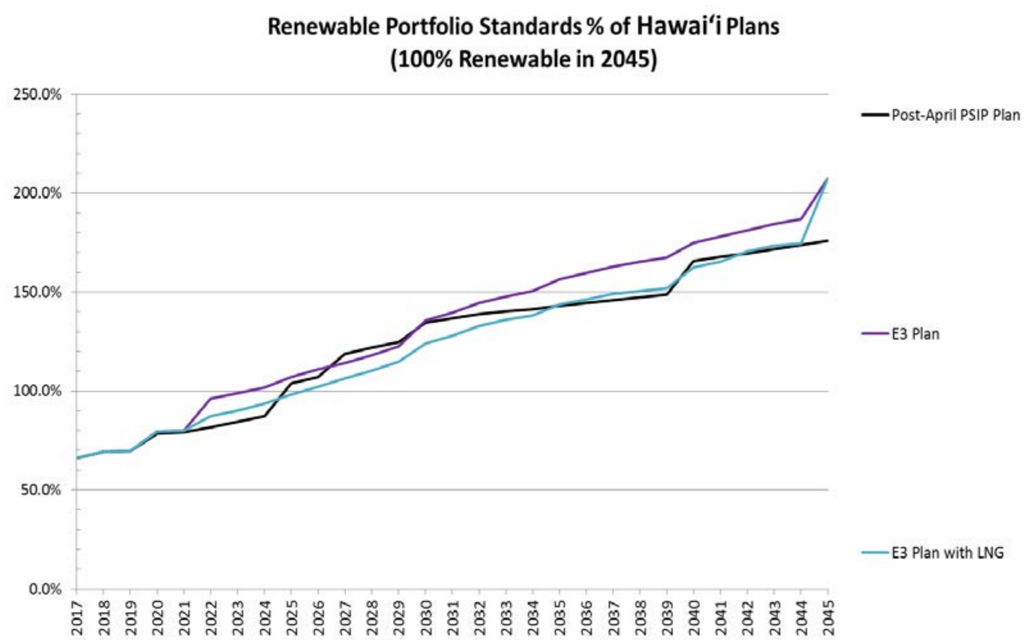

Figure K-92. Renewable Portfolio Standards Percent of Hawai'i Island Plans

The calculation of the RPS per the law does result in values over 100%. To emphasize that we are committed to achieving 100% renewable energy in 2045, Figure K-93 shows the renewable energy as a percent of total energy including customer-sited generation.

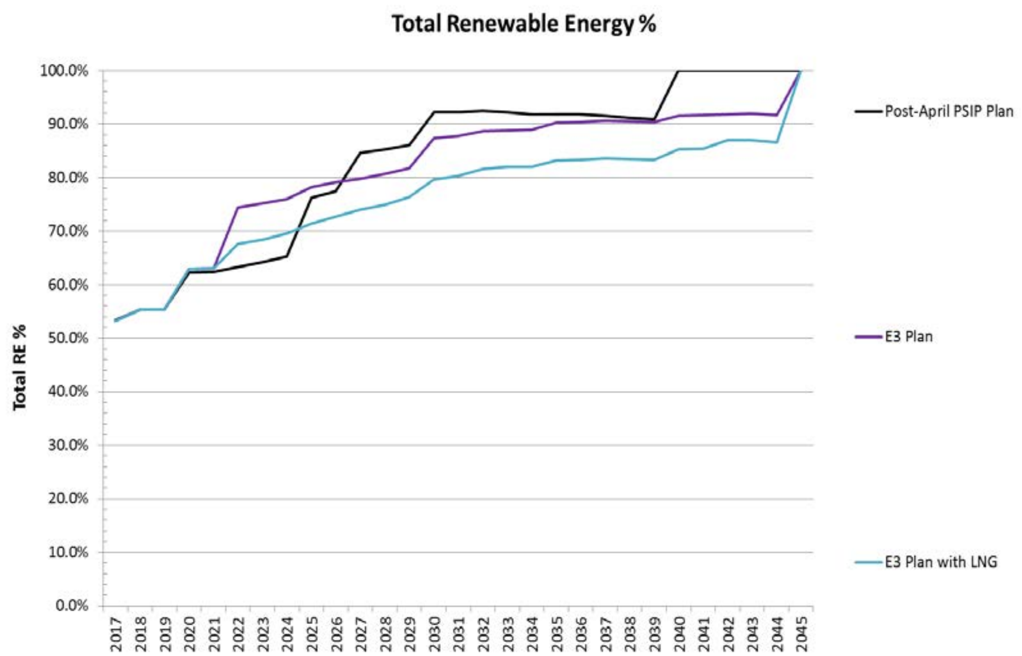

Figure K-93. Total Renewable Energy Percent of Hawai'i Island Plans

The resource mix for the plans changes over time as it reaches 100% renewable in 2045 for the E3 plans and 100% renewable in 2040 for the Post-April PSIP Plan.

The annual energy served by resource type is shown in Figure K-94 for the Post-April PSIP Plan. The transition to renewable wind and solar can be easily seen as the fossil fuel (oil) significantly decreases over time.

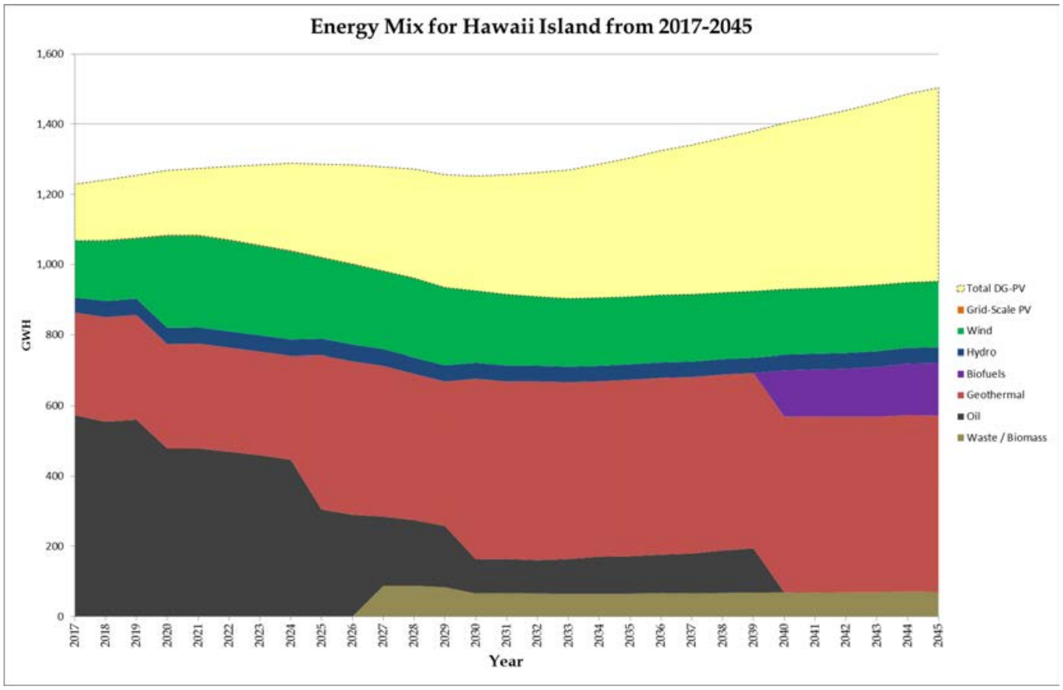

Figure K-94. Energy Mix for Post-April PSIP Plan on Hawai'i Island

Figure K-95 shows the energy mix of the E3 Plan.

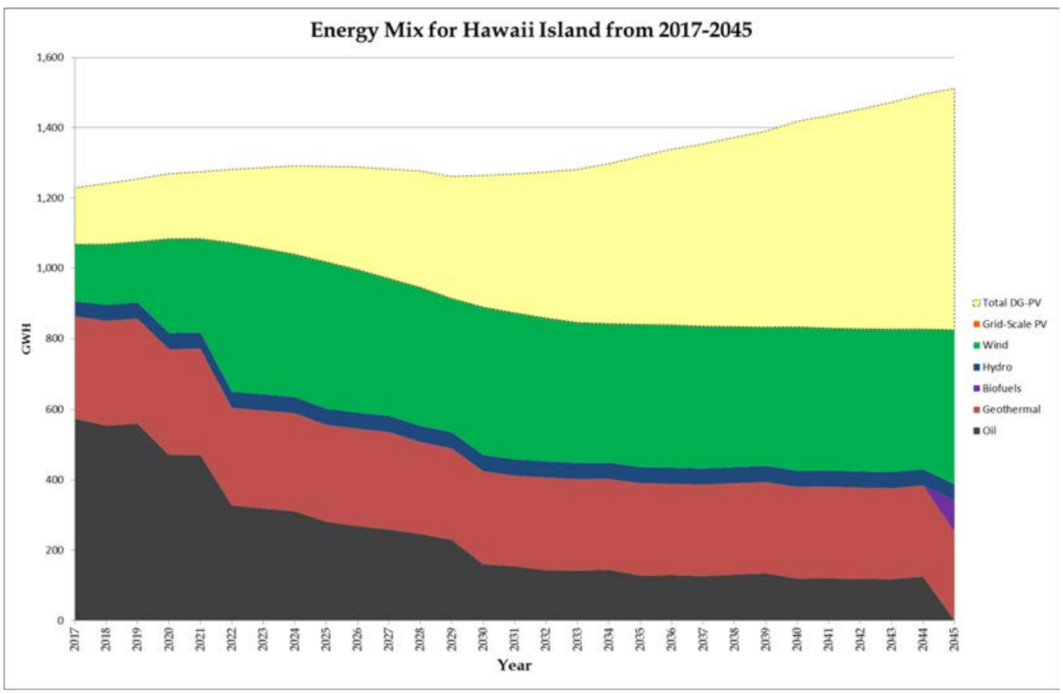

Figure K-95. Energy Mix for E3 Plan on Hawai'i Island

The E3 Plan with LNG uses LNG as a transitional fuel from oil. Renewable energy is added economically to meet intermediate RPS targets and ultimately 100% renewable energy in 2045. The energy mix for E3 Plan with LNG is shown in Figure K-96. The

transition to LNG assumes a contract period of 2022–2041. During the last intervening years in the transition to 100% renewable energy, potential future resources at this time could include biofuels, LNG, oil, other renewable options or a mix of options. Given rapidly evolving energy options and technology, the exact fuel mix is difficult to predict today.

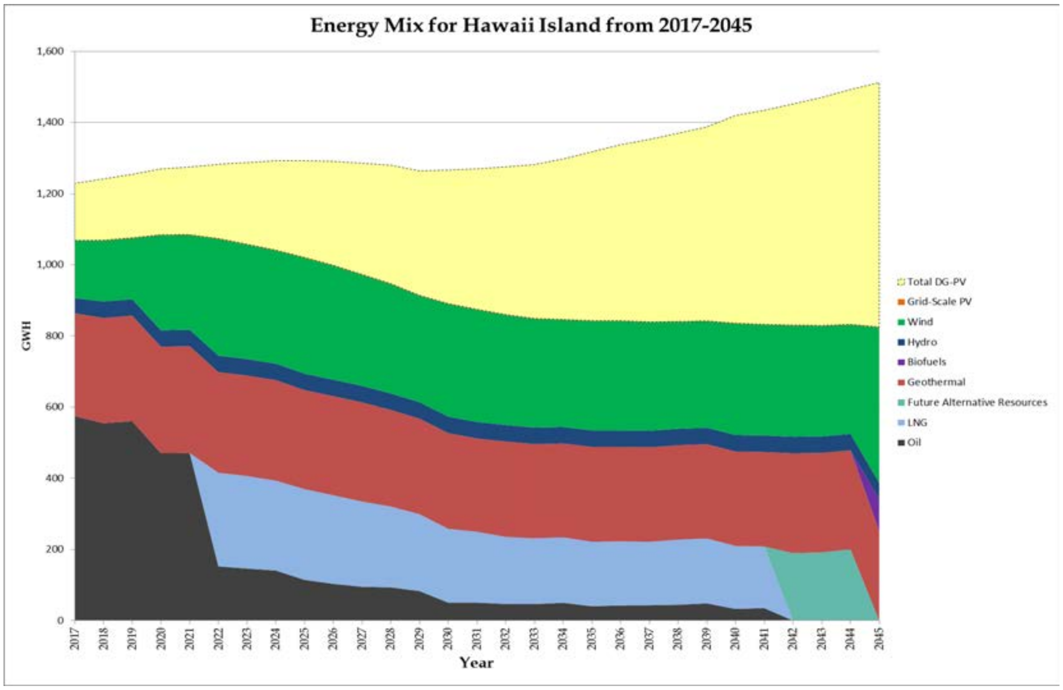

Figure K-96. Energy Mix for E3 Plan with LNG on Hawai‘i Island

Percent Over-Generation of Total System for Hawai‘i Island Plans

As increasingly more renewable energy is added to the system, over-generation occurrences will become inevitable. Figure K-97 provides estimates of the percent over-generation of the total system annual energy for the various plans. Since the E3 Plan integrates greater amounts of grid-scale wind and earlier than the Post-April PSIP Plan, the percent over-generation increases significantly in the 2022 timeframe compared to the Post-April Plan. Load-shifting storage was not included in the Post-April PSIP Plan, but was included in the E3 plans, resulting in lower over-generation in the E3 plans overall when compared to the Post-April PSIP Plan. Although the E3 plans add load-shifting storage, situations of over-generation provide opportunities, coupled with appropriate controls systems, to allow wind and solar generation to contribute to regulation up resources in addition to use as a reserve resource. This provides improved system performance. In combination, wind and solar used for energy and some level of regulation and reserve appears to be cheaper than the alternative of additional storage, at least at moderate over-generation levels. For the purposes of this December 2016 PSIP update (similar to the April 2016 PSIP update), we include the full cost of the grid-scale wind and grid-scale PV resources in cost calculations, regardless of over-generation levels and provide a simplified accounting for other services from these resources.

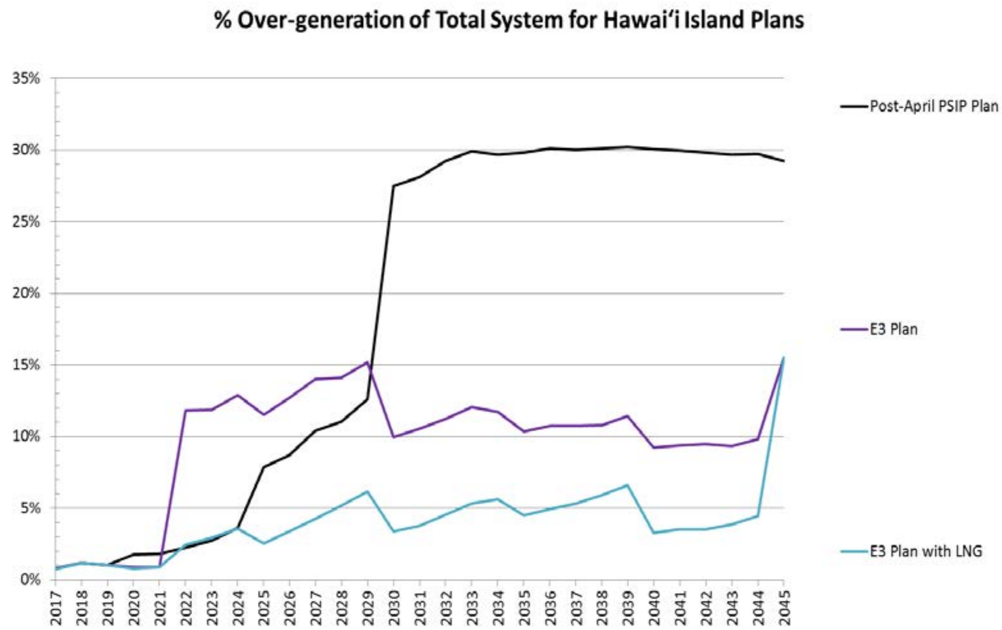

Figure K-97. Total System Over-Generation Percent for Hawai'i Island Plans

Unserved Energy of Hawai'i Island Plans

While periods of over-supply exist as described above, periods of unserved energy can also occur. The plans evaluate whether sufficient generation to serve load exists with variable renewable energy and storage with minimal conventional thermal resources on the system. The E3 plans identified existing conventional thermal generating units that could be considered for removal from service as an economic option. For the PLEXOS modeling of the E3 plans, these units were made unavailable to serve load or "offline". If there was sufficient generation being provided by the remaining thermal resources, variable renewable resources, and storage, then there would not be any unserved energy. The year-by-year amount of unserved energy in hours and energy for the E3 Plan is shown in Figure K-98. For example, in 2020, there is approximately 31 MWh total of unserved energy which occurs over the course of 4 hours in the year.

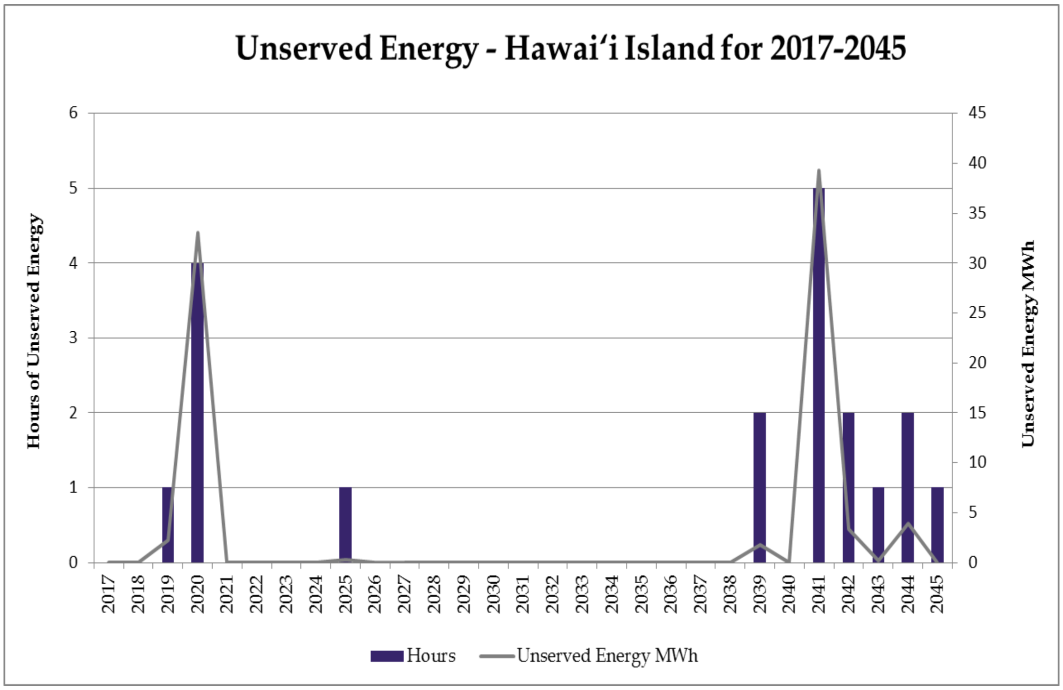

Figure K-98. Unserved Energy for E3 Plan on Hawai'i Island

Figure K-99 indicates that the Post-April PSIP Plan has about one hour of unserved energy in 2019 and does not have unserved energy until the 2038 timeframe.. The few hours of unserved energy could be investigated in more detail and may be due to thermal generating units being on maintenance which could be adjusted or refined as we approach the year of concern.

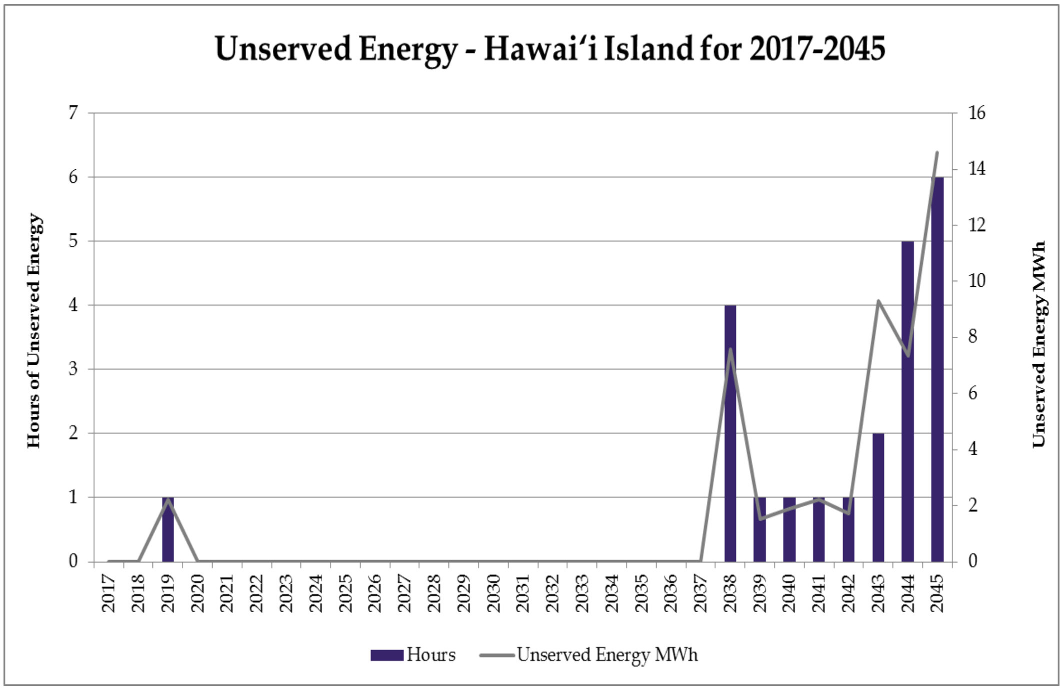

Figure K-99. Unserved Energy for Post-April PSIP Plan on Hawai'i Island

Seasonal Variations of Hawai'i Island Renewable Energy

While Hawai'i Island has firm renewable generation that is more predictably available, there is still a significant amount of variable renewable generation. Although there are diverse locations of resources, there can be periods with low production.

Figure K-100 shows the difference between the load and the available renewable energy in the year 2025. The difference must be met with thermal generation to prevent unserved energy.

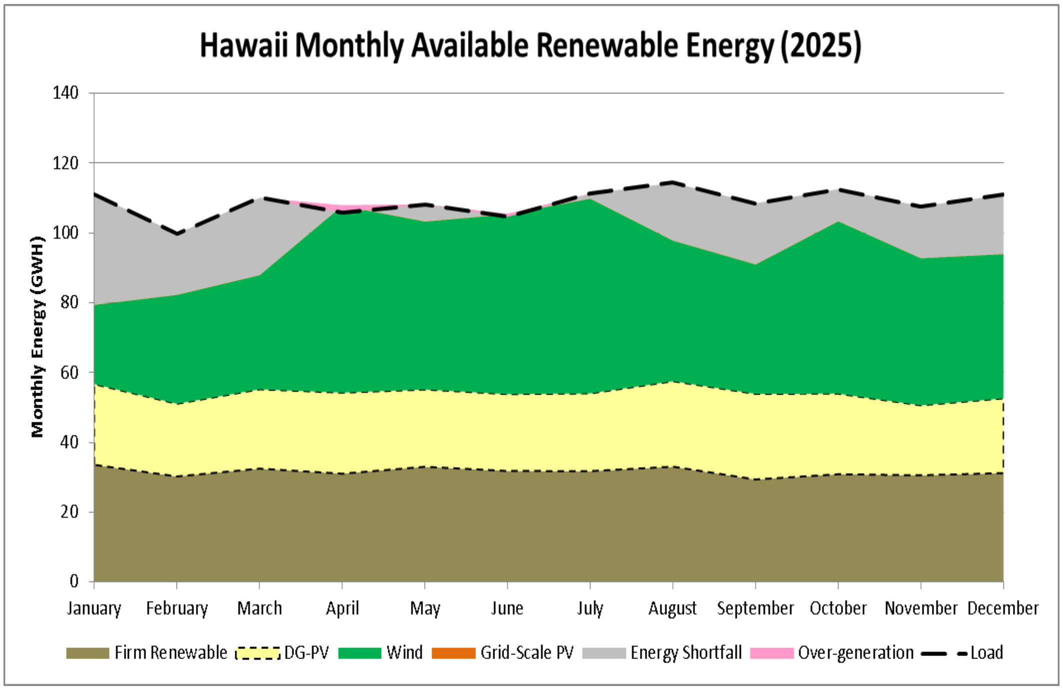

Figure K-100. E3 Plan Monthly Available Renewable Energy vs Load on Hawai'i Island in 2025

Figure K-101 shows the difference between the load and the available renewable energy in the year 2045 for the E3 Plan. Despite having high amounts of renewable energy available in some months, creating a surplus, shown in pink, there are some months for which there is a deficit, shown in gray. This highlights the continued need for thermal generators to provide supplemental generation during these shortfall periods or energy storage systems, which are capable of shifting energy over several months from the months where there is a surplus to the months where there are shortfalls.

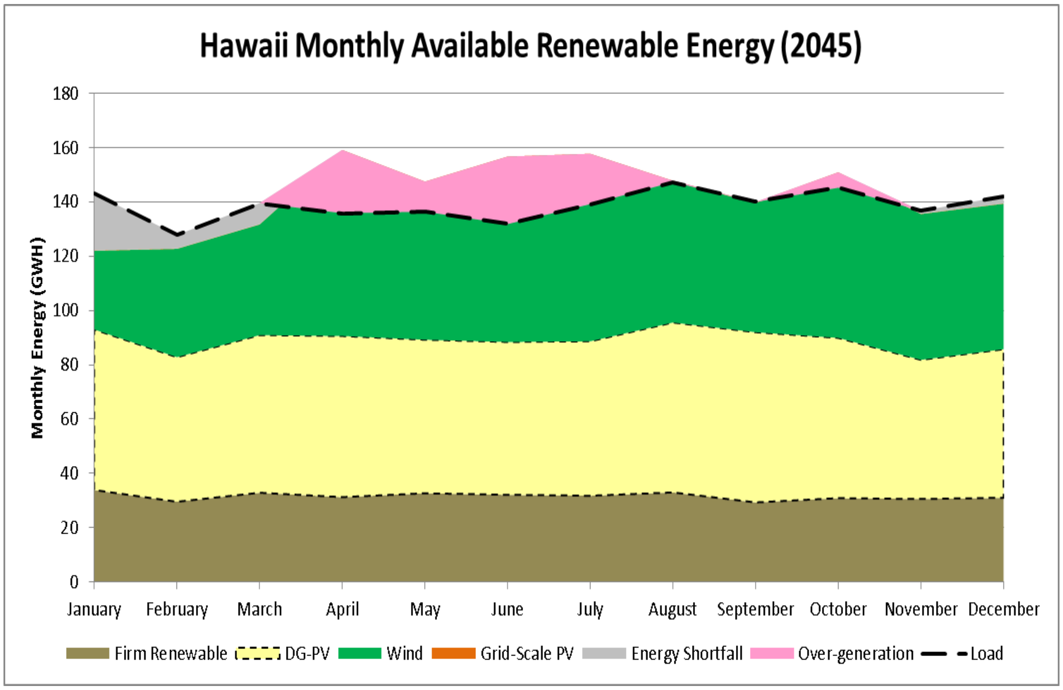

Figure K-101. E3 Plan Monthly Available Renewable Energy vs Load on Hawai'i Island in 2045

Sub-Hourly Charts of Hawai'i Island Plans

Sub-hourly modeling was performed to analyze the impact that variable renewable energy would have on our system, and whether our portfolio of generators and storage systems would be sufficient to stabilize the electrical grid.

Historical minutely renewable energy data was used to determine the volatility of solar and wind resources on Hawai'i Island. The volatility of the Apollo wind farm was applied to future grid-scale Wind resources.

An initial screening was done to determine the month with the largest potential minutely downward ramp. PLEXOS was then employed to perform a stochastic analysis on this month. Using the historical minutely data, stochastic variables were created for all as-available resources and the load. Shown below are the results from the sub-hourly analysis of the E3 Plan when a 1-, 15-, and 30-minute look-ahead is assumed.

Figure K-102 shows the estimated unserved energy at a 1 minute look-ahead. To analyze the impact of the 12 MW 4-hour load-shifting battery installed in the E3 Plan in 2020, Figure K-103 shows the estimated unserved energy at a 1 minute look-ahead without the battery in-service.

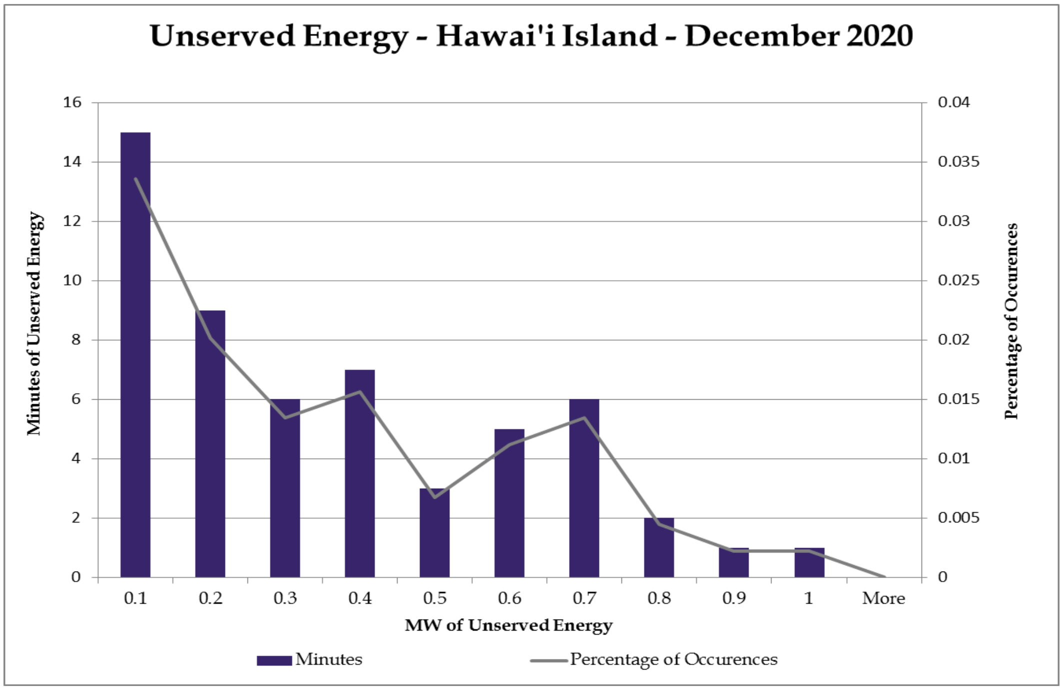

Figure K-102. Sub-Hourly Unserved Energy for E3 Plan on Hawai'i Island at 1-Minute Look-Ahead

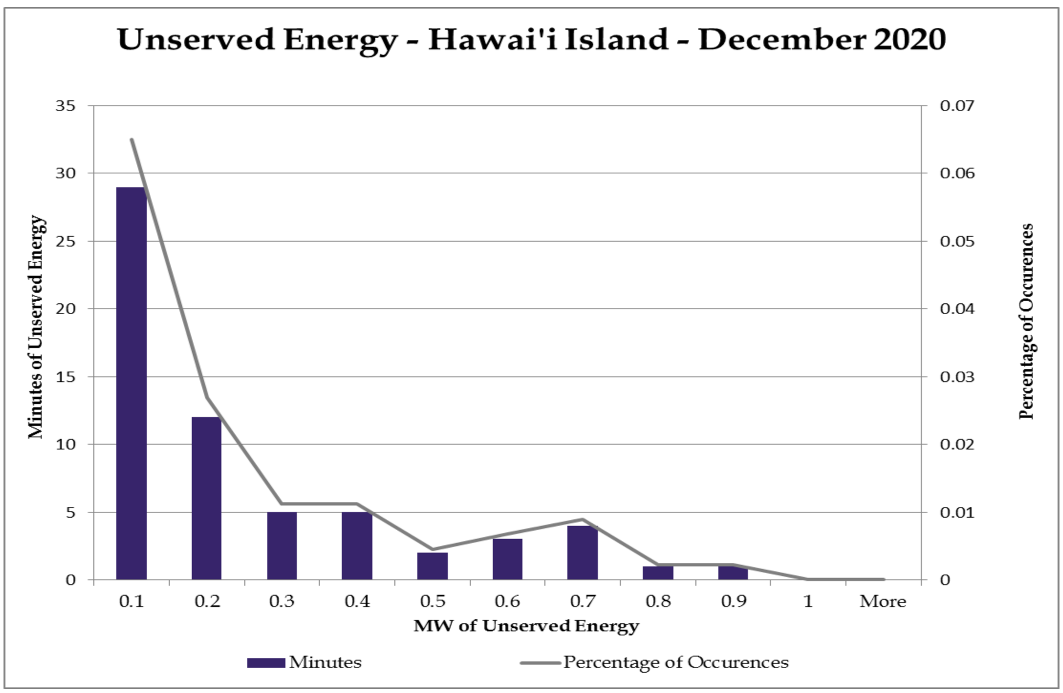

Figure K-103. Sub-Hourly Unserved Energy for E3 Plan on Hawai'i Island at 1-Minute Look-Ahead without Load-Shifting Battery

As shown in Figure K-104, the unserved energy magnitude and number of occurrences significantly decreases with 15 minute look-ahead.

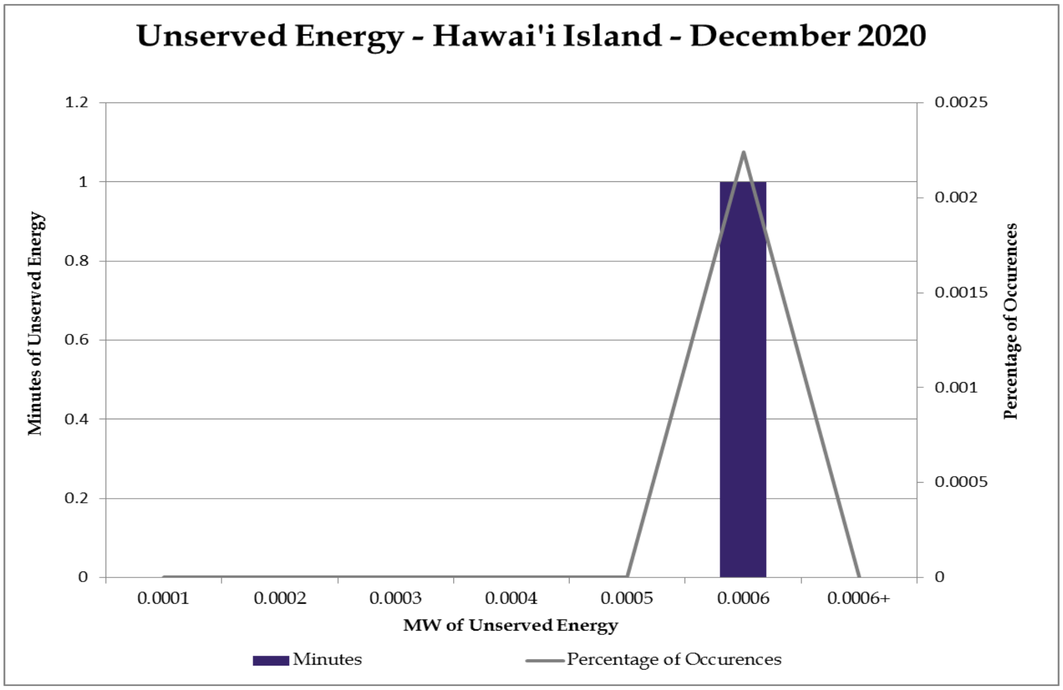

Figure K-104. Sub-Hourly Unserved Energy for E3 Plan on Hawai'i Island at 15-Minute Look-Ahead

With a 30 minute look-ahead setting, there is virtually no unserved energy.

Daily Energy Charts of Hawai'i Island Plans

The charts in the previous sections displayed annual and monthly views of how renewable energy is being integrated into the plans and the impacts to the system energy production. This section will convey a more granular view by providing the energy mix for select days of some years of the plans that were modeled.

High Over-Generation Energy Profiles for E3 Plan

Figure K-105 provides a view of the day in the year 2020 that has the highest amount of over-generation for the E3 Plan. It can be seen that during the middle of the day, almost all of the load is being served by renewable energy. During this time, storage is being charged then discharged in the evening..

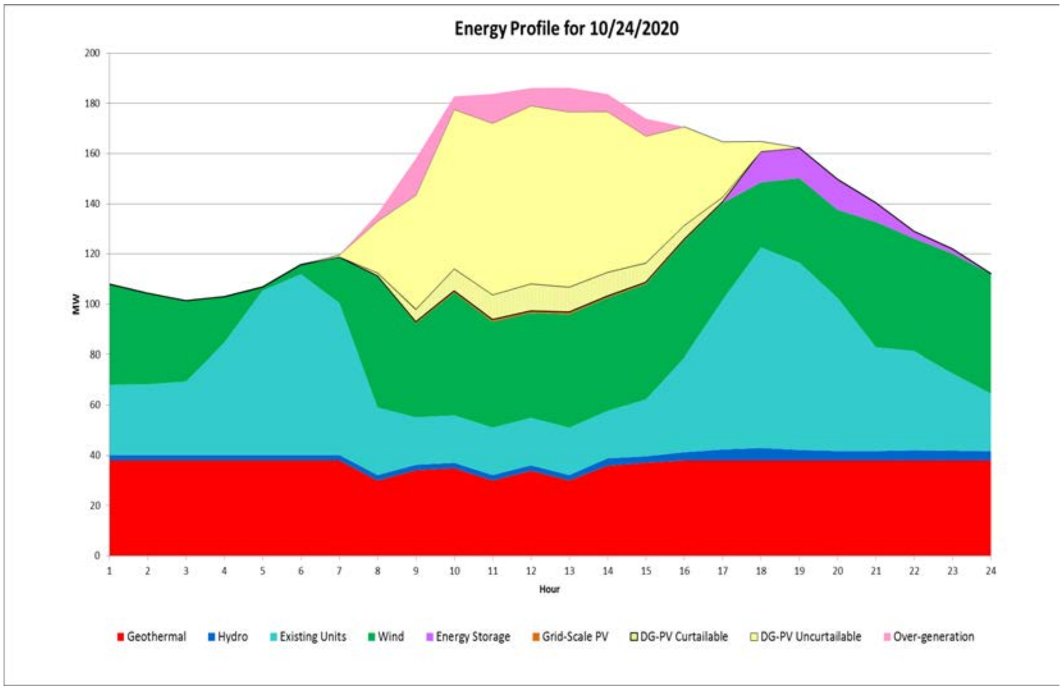

Figure K-105. E3 Plan Hawai'i Island High Over-Generation Energy Profile: 2020

Figure K-106, Figure K-107, and Figure K-108 shows virtually all of the energy provided on high over-generation days in 2030, 2040, and 2045, respectively, is through renewable resources. On these days, over-generation occurs in almost every hour of the day and energy storage is discharged in the evening.

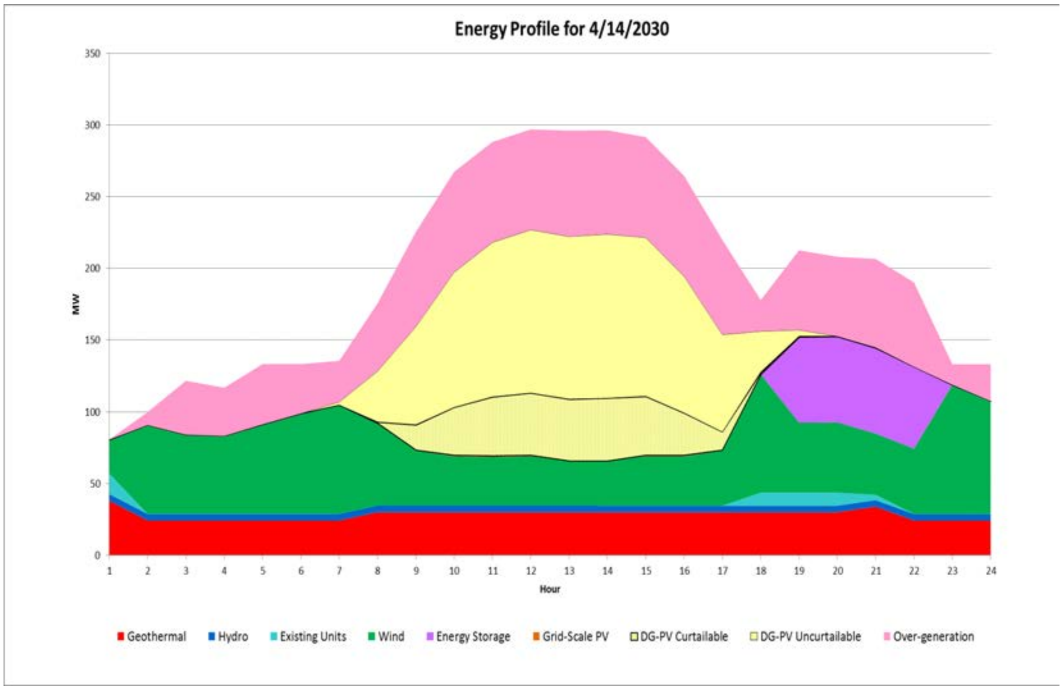

Figure K-106. E3 Plan Hawai'i Island High Over-Generation Energy Profile: 2030

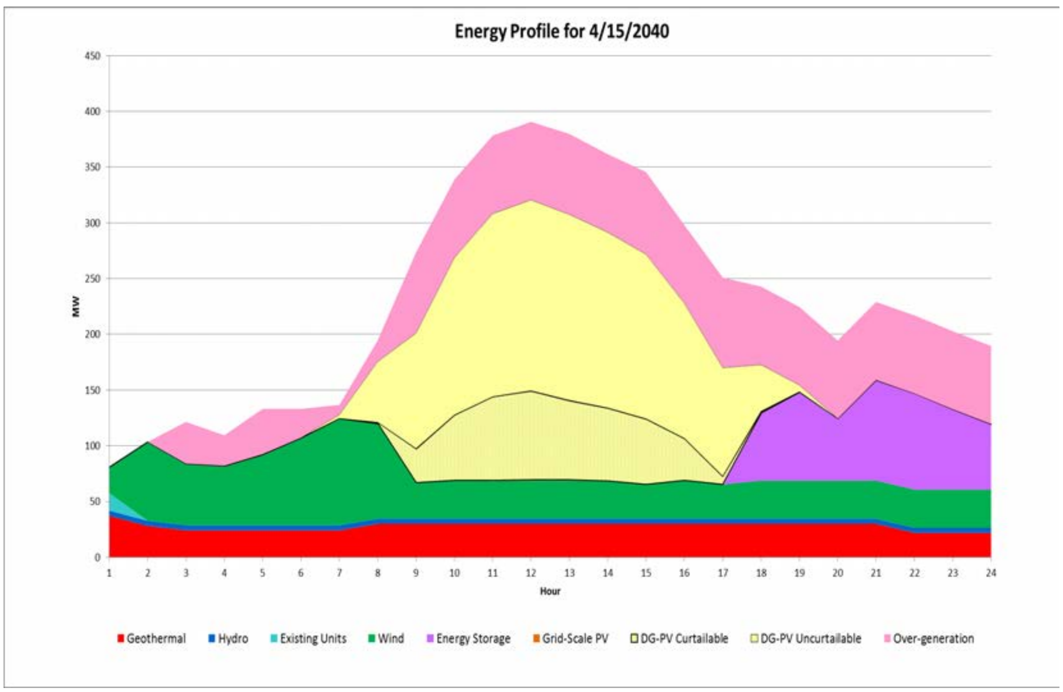

Figure K-107. E3 Plan Hawai'i Island High Over-Generation Energy Profile: 2040

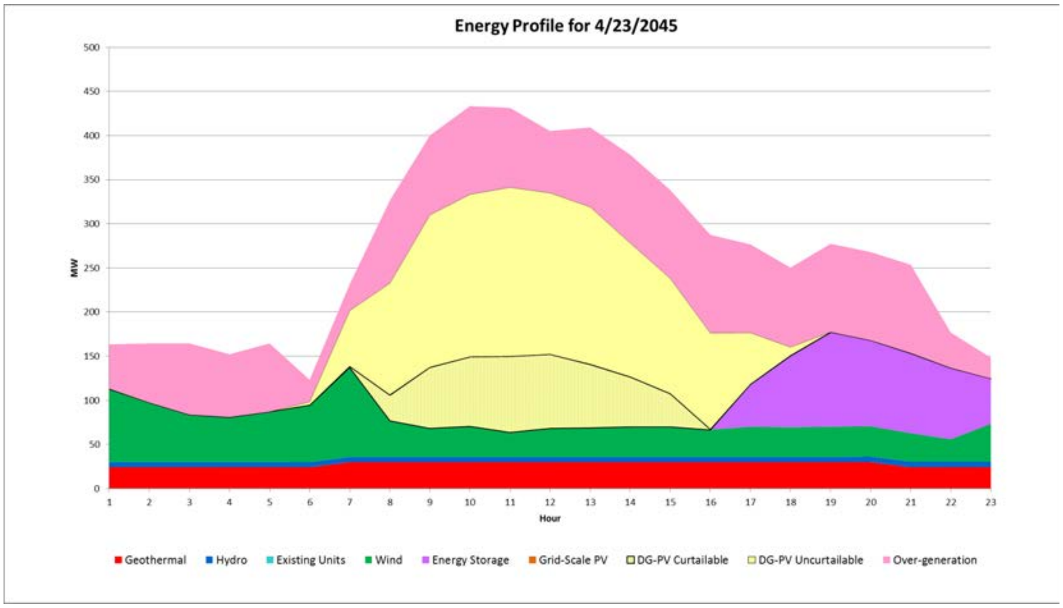

Figure K-108. E3 Plan Hawai'i Island High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for E3 Plan

Although Hawai'i has abundant renewable resources, such as wind and solar, there are days for which there is limited solar and/or limited or no wind available. Figure K-109, Figure K-110, Figure K-111, and Figure K-112 illustrates how different the energy profile is for the days with low renewable energy available in the years 2020, 2030, 2040, and 2045, respectively, for the E3 Plan. Even in later years, such as 2040 and 2045, where there are significant amounts of renewable resources and energy storage included in the plan, on these low renewable days, thermal generation is still necessary to serve the load.

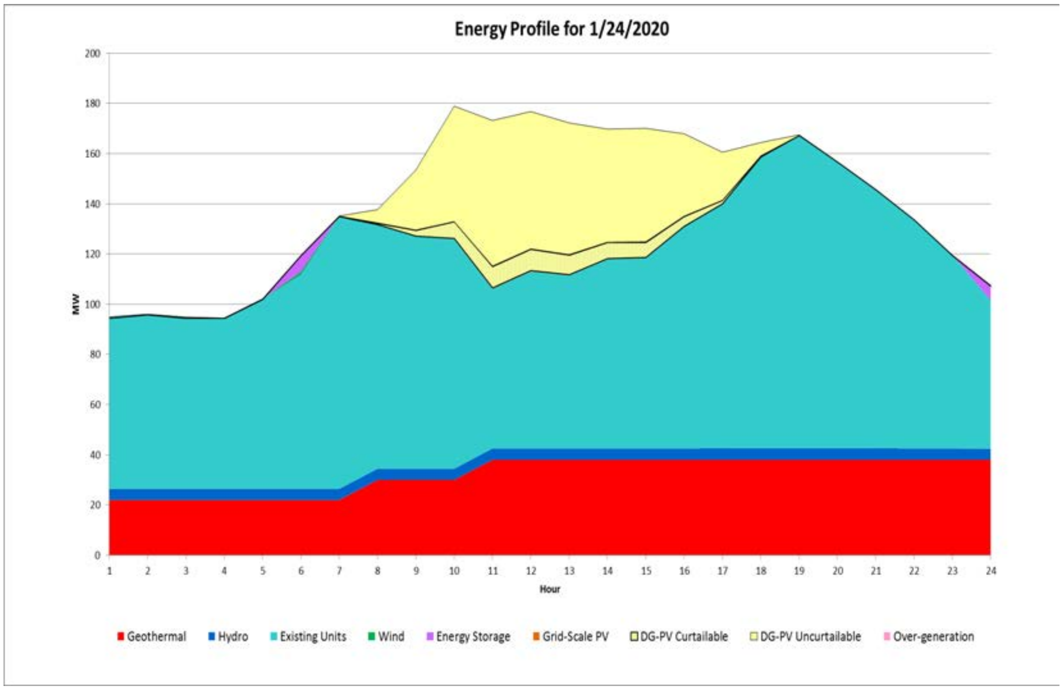

Figure K-109. E3 Plan Hawai'i Island Low Renewables Energy Profile: 2020

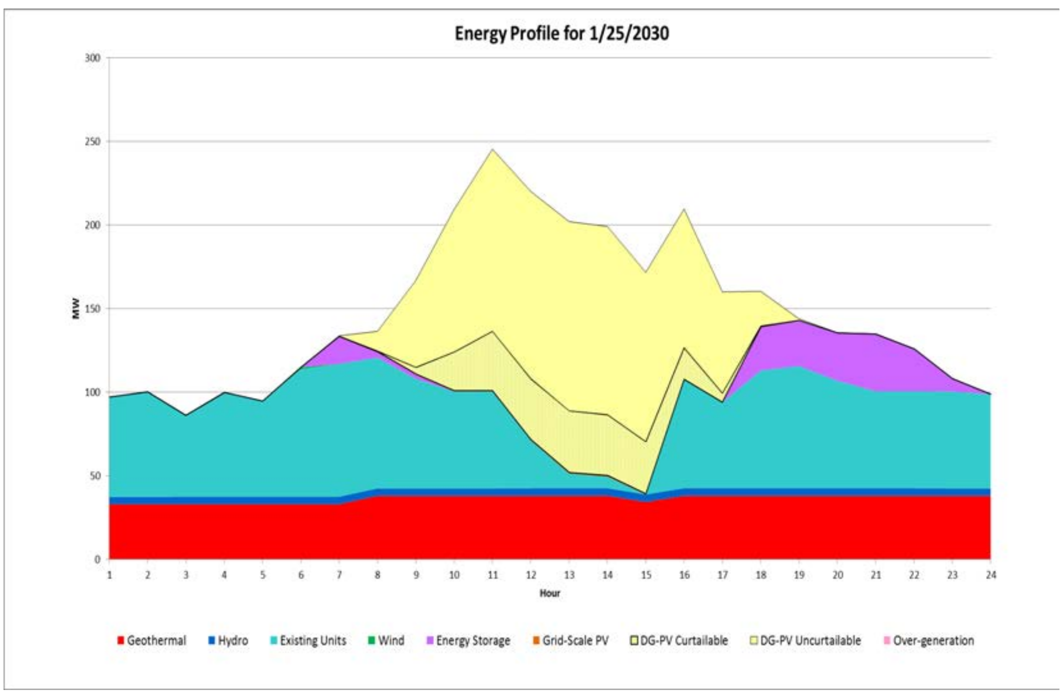

Figure K-110. E3 Plan Hawai'i Island Low Renewables Energy Profile: 2030

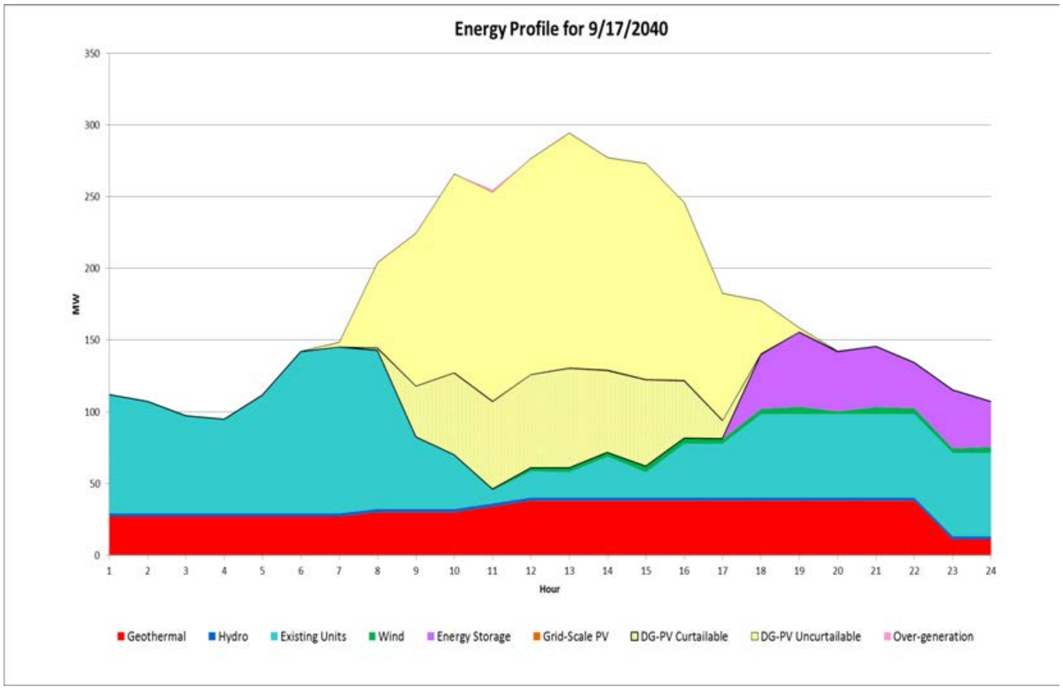

Figure K-111. E3 Plan Hawai'i Island Low Renewables Energy Profile: 2040

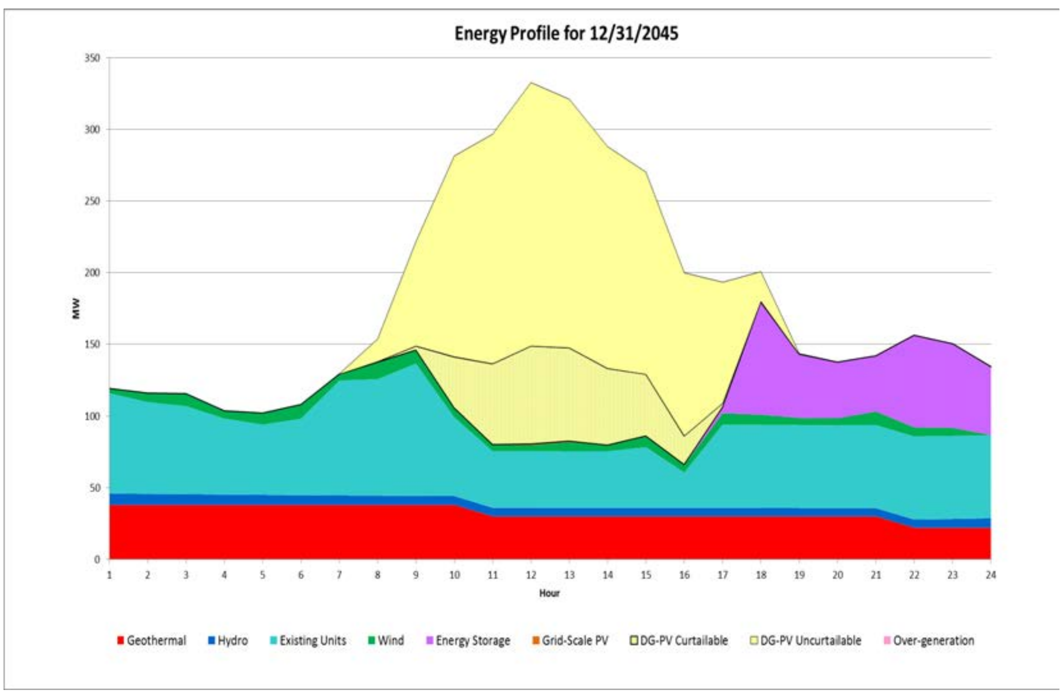

Figure K-112. E3 Plan Hawai'i Island Low Renewables Energy Profile: 2045

High Over-Generation Energy Profiles for Post-April PSIP Plan

Since the Post-April PSIP Plan has a different resource mix than the E3 plans, the daily energy profiles for the same years (2020, 2030, 2040, and 2045) are provided below.

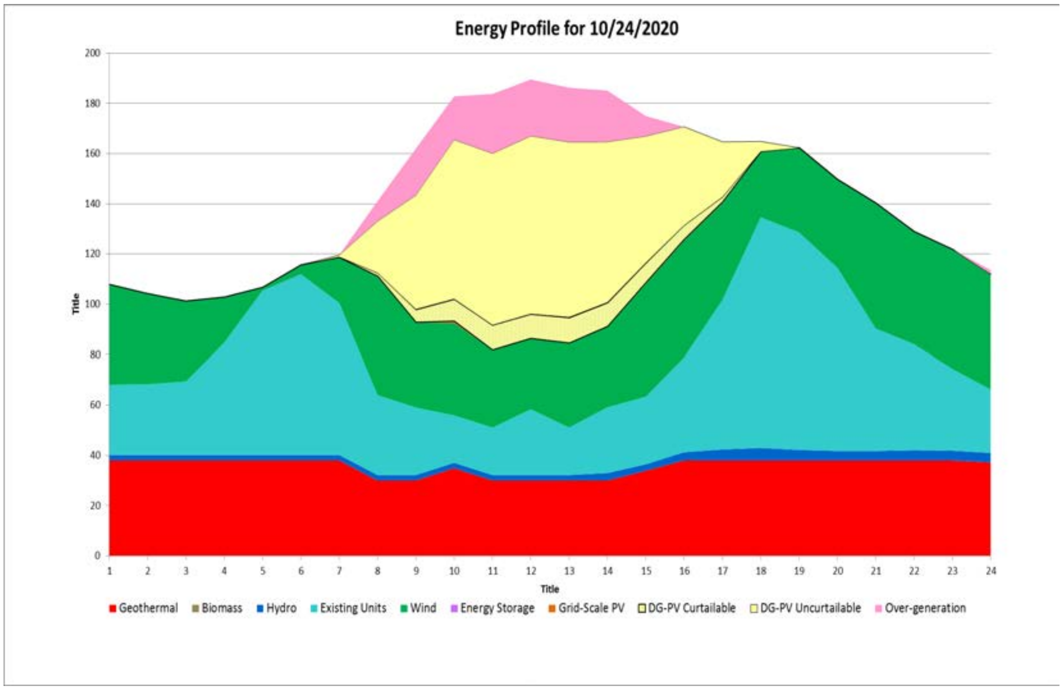

Figure K-113. Post-April PSIP Plan Hawai'i Island High Over-Generation Energy Profile: 2020

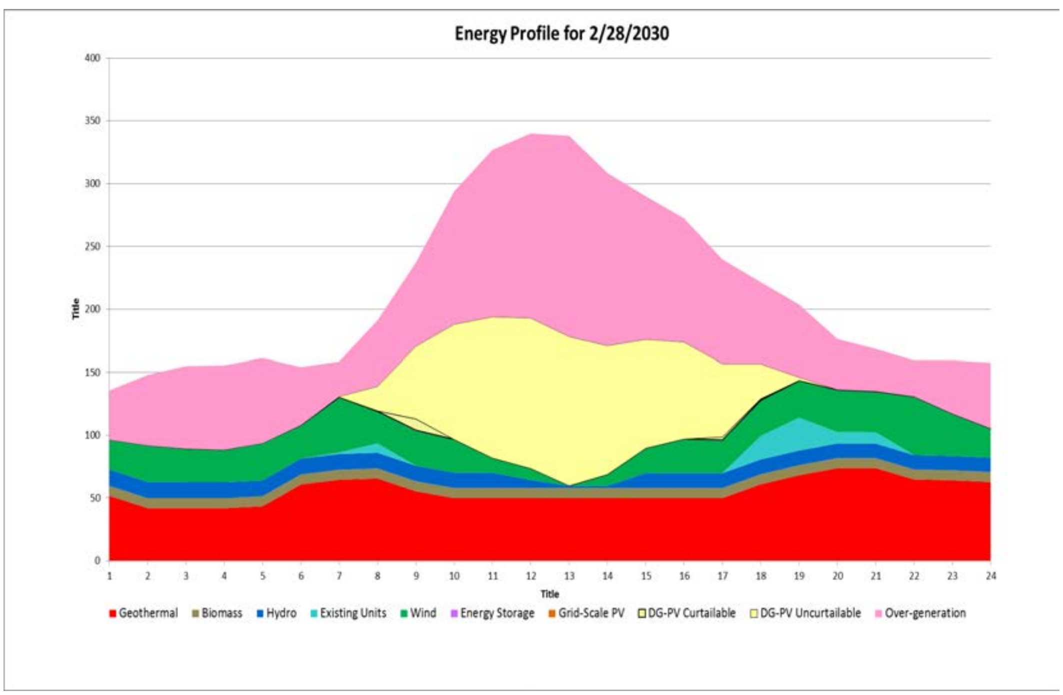

Figure 4-114. Post-April PSIP Plan Hawai'i Island High Over-Generation Energy Profile: 2030

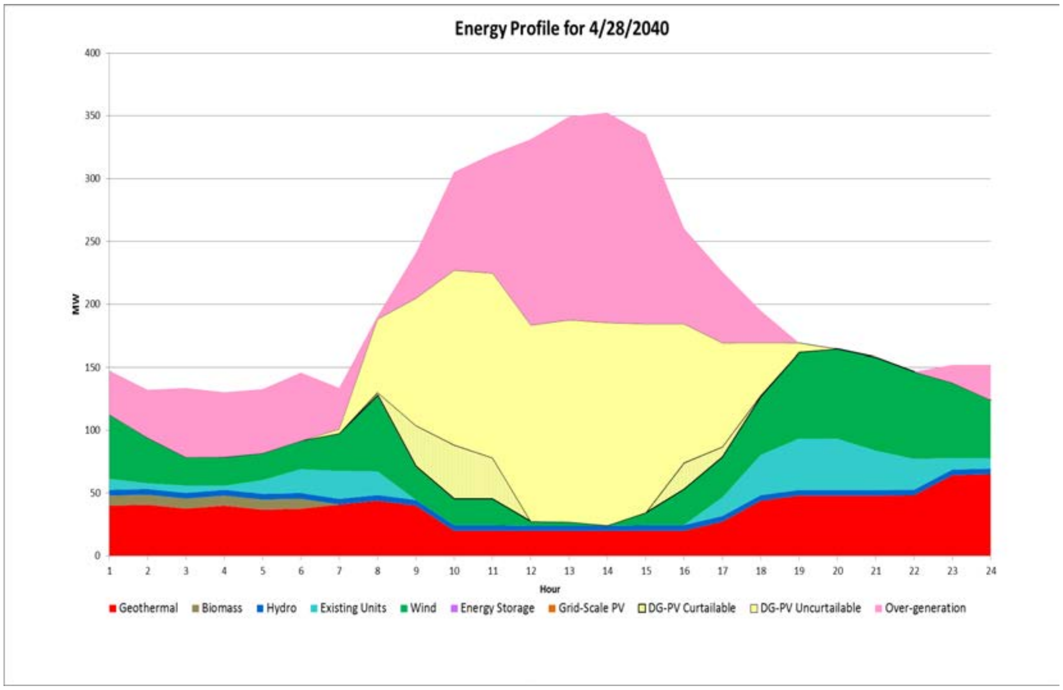

Figure K-115. Post-April PSIP Plan Hawai'i Island High Over-Generation Energy Profile: 2040

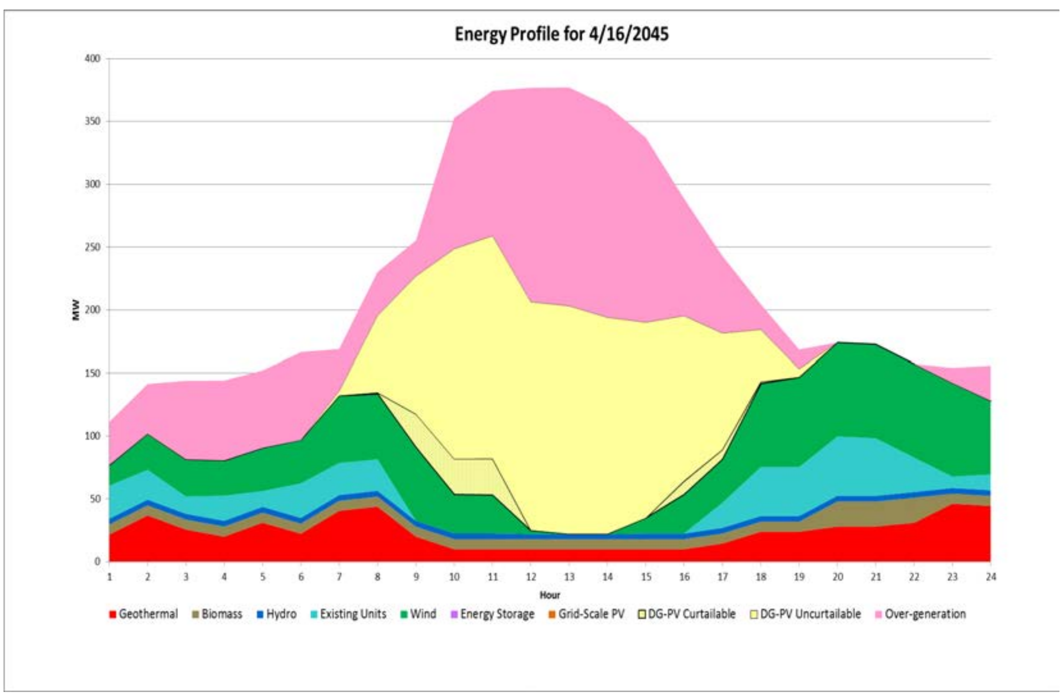

Figure K-116. Post-April PSIP Plan Hawai'i Island High Over-Generation Energy Profile: 2045

Low Renewable Energy Profiles for Post-April PSIP Plan

The daily energy profiles for the same years (2020, 2030, 2040, and 2045) for the Post-April PSIP Plan are provided below as a comparison to the E3 plans.

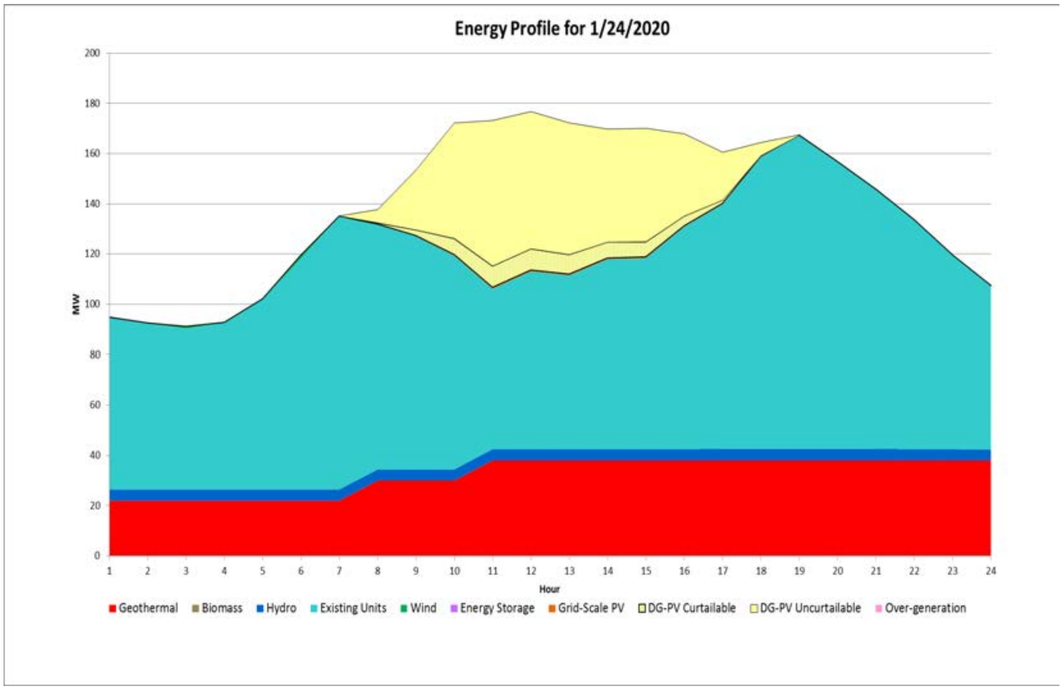

Figure K-117. Post-April PSIP Plan Hawai'i Island Low Renewables Energy Profile: 2020

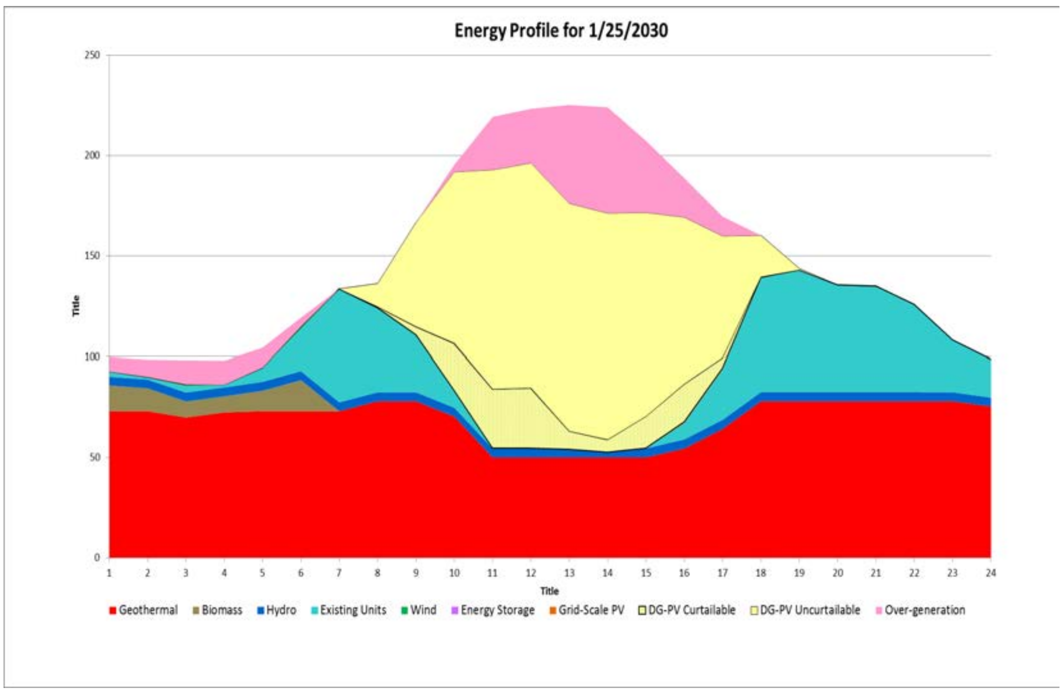

Figure K-118. Post-April PSIP Plan Hawai'i Island Low Renewables Energy Profile: 2030

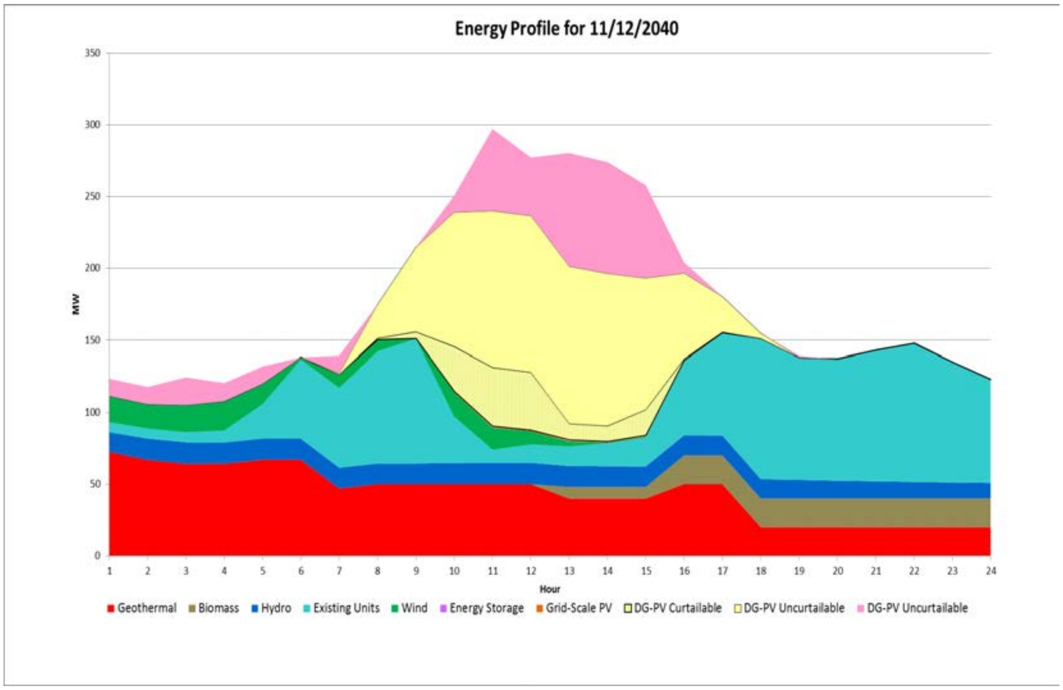

Figure K-119. Post-April PSIP Plan Hawai'i Island Low Renewables Energy Profile: 2040

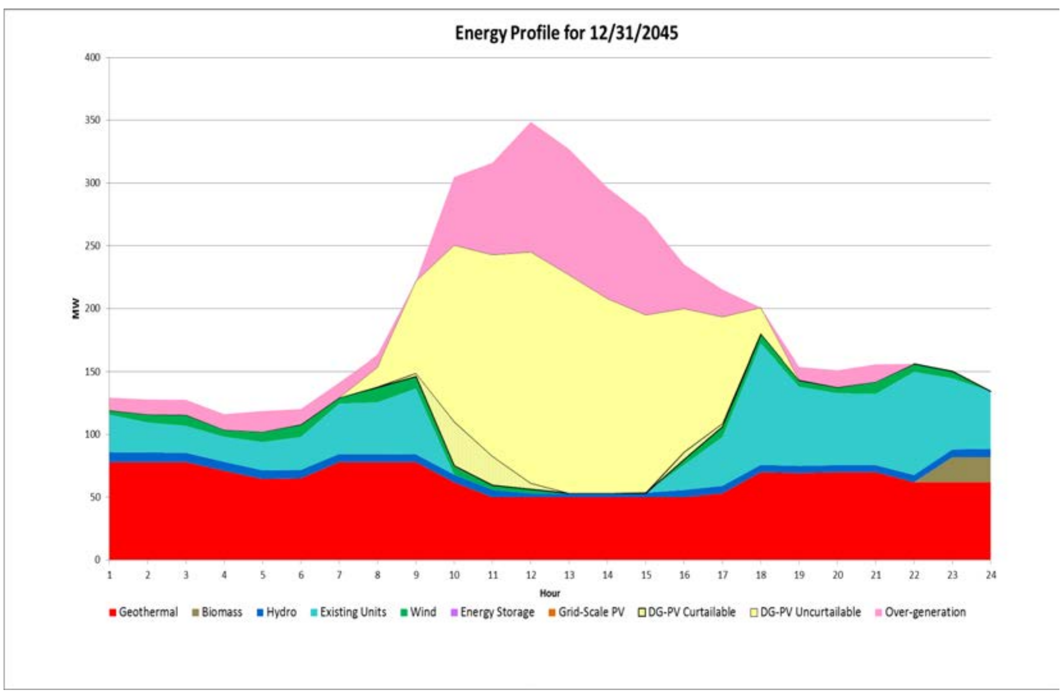

Figure K-120. Post-April PSIP Plan Hawai'i Island Low Renewables Energy Profile: 2045

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

L. EPRI Reserve Determination

Hawaiian Electric has assembled a study team to propose a new method for determining operating reserve requirements based on an EPRI study for determining the impacts of wind and solar on system operations. Since the O‘ahu island system is highly sensitive to frequency swings, this study, conducted only on the O‘ahu grid, focused on short-term frequency regulating reserve.

The study uses a multi-cycle power system operations model (one that simulates the multiple decision-making procedures taken in real operations) to:

- Analyze costs, area control error (ACE), and frequency of the current reserve requirement method versus the proposed method—for current and future renewable penetration on the O‘ahu system.
- Represent the various decisions made by O‘ahu system operators.
- Stochastically represent wind, solar, load, and outages, as well as short-term operations.

The study also considers sensitivities, including using battery energy storage systems (BESS) and regulation reserve during renewable ramping periods combined with a generating contingency event.

This process will allow us to better understand how reserves are currently being used and how new methods (including those based on the stochastic nature of wind, solar, and load) could improve upon the optimal amount of reserve needed for the system. The study's finding will inform the development of new short-term operational tools to manage wind and solar variability and uncertainty, which might include conditional rules for procuring and deploying reserves. The study also examines how a BESS installed and used for providing reserves operates.

The study progressively adds more detail to individually examine each of these factors.

When the study completes, EPRI and Hawaiian Electric will work together to ensure that the results can be transferred to operating practices and their energy management system tools. The goal is not to develop online operating tools, but rather examine some of the potential operating solutions through realistic simulations.

The study team is using the FESTIV simulation tool which incorporates unit commitment, economic dispatch, automatic generation control, and contingency-based operator action. The tool is unique in being able to simulate the long-term scheduling and commitment of resources days and hours ahead, while also simulating the fast second-to-second control and frequency impacts of the system.

Thus far, the study team:

- Collected eight weeks of historic high-resolution load, conventional generation, and renewable data, then constructed the input files necessary to run the simulation tool.
- Developed a module to better simulate frequency of the O‘ahu system using the O‘ahu frequency bias and ACE.
- Developed a module to mimic O‘ahu’s “equal lambda criterion” automatic generation control (AGC) simulation model, which determines production levels based on O‘ahu generator quadratic cost functions.
- Incorporated numerous reliability must-run, derate, and other specific rules to benchmark unit generation, frequency, and ACE.
- Performed simulations of all eight weeks using the base case reserve requirement method.
- Created near-future (circa 2018) cases from the eight weeks of high-resolution data to include the forecasted future central and distributed renewable resources.
- Performed simulations of the future cases and analyzed the frequency, cost, and ACE impacts under both the current reserve method and the GE-proposed reserve method.
- Repeated the simulations and the analyses of the future cases with all units (but Kahe 5 and Kahe 6) as flexible (rather than must-run) to understand how this will change the benefits and impacts of the reserve methodologies.

The study team will evaluate the periods where greater imbalance was occurring, and using probabilistic renewable generation forecasts and variability statistics, propose a reserve requirement determination method with improved performance based on economic or reliability factors. A preliminary evaluation of the benefits of implementing the EPRI methodology is expected sometime in the first quarter of 2017; the final analysis and report for the entire effort is expected by end of the second quarter of 2017.

O‘ahu is using the GE method; Maui and Hawai‘i Island are using the EPS method.

ASSESSMENT OF GE STUDY AND EPS RESERVE METHODOLOGY

The report, *Proposed HECO Regulation–From Measured Wind and Estimated Solar Data* (conducted by EPS and published August 5, 2014), assesses their proposed reserve methodology. We forwarded this report to EPRI for their assessment. Based on a high-level review of the proposed approach, EPRI indicated that a more efficient reserve procurement approach can be specified while still maintaining a satisfactory level of reliability. EPRI suggested four categories of improvements. The first improvement's description is different for the GE study and EPS methods. The remaining three improvements are essentially the same for both methods.

GE Improvement 1: Assumption of Correlation of Wind and Solar with Load

The GE study method improves upon the EPS reserve method in two ways:

- Assessing overall renewable ramps rather than just wind and solar ramps individually.
- Using the difference between daytime (with PV)and nighttime ramps (without PV), which can better show the maximum expected ramps for both periods.

Thus, the correlation between wind and solar is captured to better determine overall regulation needs for the system. From EPRI simulations, this results in a much lower reserve requirement for a lower system cost with negligible reliability impacts. For example, evaluating a week in Spring 2014 showed costs reduced by $35,000 while the standard deviation of ACE was decreased by 0.2 MW. In addition, Hawaiian Electric's compliance measure (the percent of time where frequency deviates by more than 50 MHz) was decreased by 0.2%.

Hawaiian Electric plans to assess how the renewable impact correlates with load ramps, as the load level can have a significant impact on the anticipated level of ramping on the system.

EPS Improvement 1: Assumption of Correlation of Wind and Solar with Load

The EPS method presented separate, total regulation requirement for wind and solar, based on covering large ramps of each type of resource. Separating the requirements for isolating wind and PV ramping to attain the total required regulation essentially assumes that wind and solar are perfectly correlated (that is, the largest wind ramp will occur simultaneously with the largest solar ramp).

The EPS proposed method calculates reserve requirements based on total wind or total solar rather than summing the requirement to cover the ramping of individual wind plants and individual solar plants. Because of this, the reserve determination requirement should consider the total ramp from total renewables based on output level rather than each technology individually. For example, it may be that the EPS method requires substantial regulation requirement to cover wind ramps that are ramping down during a period when solar is ramping up such that the net variability is not as significant.

Similarly, the reserve requirement should be evaluated with load to cover the net load variability and not just the aggregate renewable ramping. Requirements can use multi-dimensional lookup tables for regulation requirements (for example, for particular wind, solar, and load conditions, carry some MW level of regulation reserve).

With further analysis, this enhancement to the method can reduce the amount of reserve while having negligible reliability impacts. This would involve assessing the relationship between wind, solar, and load variability and, based on this relationship, developing a requirement to cover the maximum largest ramps.

One of the key challenges will be ensuring sufficient representative data is available so that the worst case events can be identified. Lacking sufficient confidence in this, then some margin may be needed above the amount that data analysis may identify as needed.

GE and EPS Improvement 2: 1:1 Ratio and Percentage Level Cap

The GE study and EPS methods use a 1:1 approach that requires 1 MW of reserve for every MW of production, up to a certain percentage level of wind or solar. Above that, no incremental reserve requirements are needed. The study team was unable to determine why these approaches were taken based on the data available to EPRI; the use of 1:1 ratios and the cap percentage above which no more is needed both seem arbitrary.

Figure L-1 and Figure L-2 shows that application of the GE study and EPS method requirement (respectively) in red for PV ramping data. This data is the Maui Electric results in holding more than twice the reserve required to cover ramps for some lower PV levels and a deficit in reserve to fully cover PV ramps for some higher PV levels.

Even if the system required 100% compliance of meeting the 20-minute ramp, a segmented curve that doesn't keep the arbitrary 1:1 ratio can be used as shown in yellow. This would meet all of the historical ramps based on the data shown, such that over-procuring reserve requirements would be significantly reduced. Even if a margin is desired, the yellow line is significantly lower at lower PV output.

Applying a segmented reserve requirement curve approach for each operating company may reduce costs by reducing unnecessary reserves while providing greater compliance by covering ramp events between 20 and 30 MW outputs—this wouldn't have been guaranteed in the previous method.

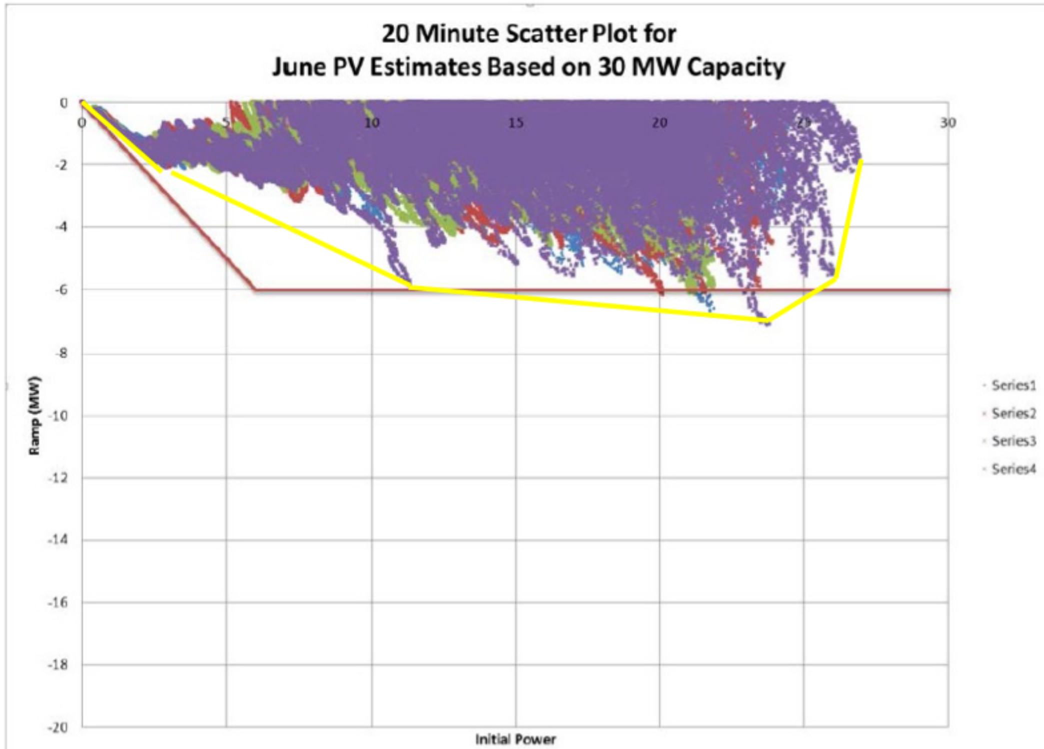

Figure L-1. GE Study Method 20-Minute Solar PV Ramp Rates: 100% Reserve Requirement

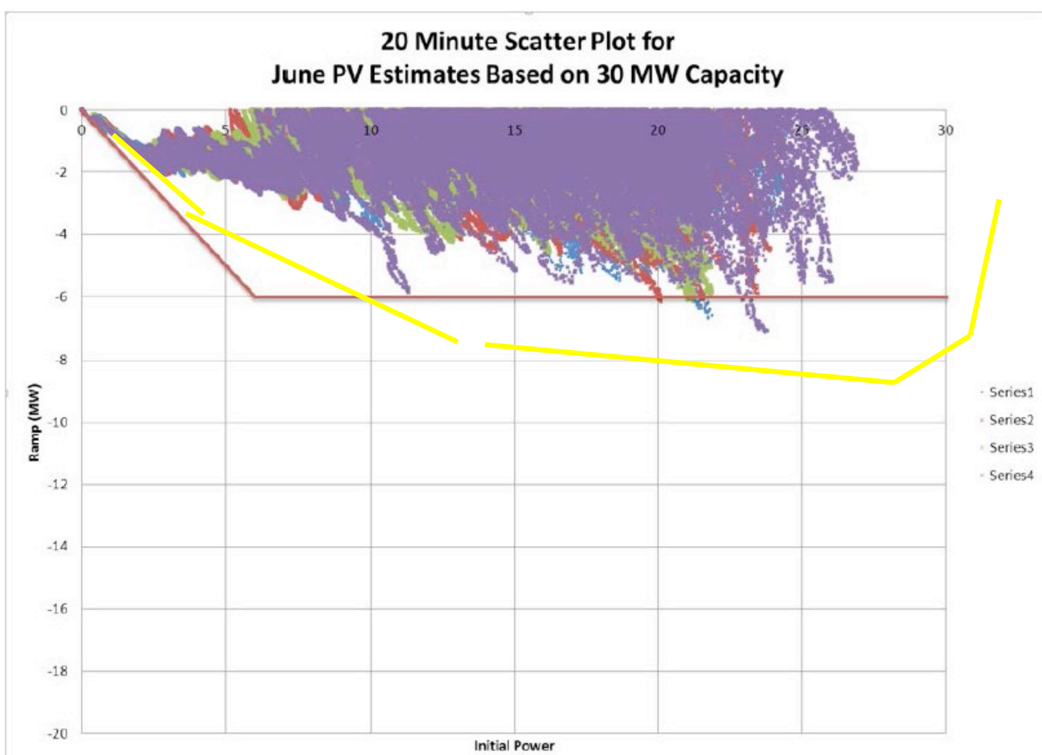

Figure L-2. EPS Method 20-Minute Solar PV Ramp Rates: 100% Reserve Requirement

GE and EPS Improvement 3: 100% Compliance Assumption

Mainland balancing compliance requirements are based on statistically ensuring that imbalances do not get large enough to trigger under-frequency load shedding for N-1. They are also rarely defined other credible events (for example, N-2). For normal balancing, the current NERC standard is that the imbalance be less than some specified MW level for 90% of the time.

For an interconnected system with peak load similar to Hawaiian Electric, the imbalance level must be less than approximately 25 MW for 90% of the time. Because of the isolated nature of the Oʻahu island system, the allowable imbalance levels must be maintained lower than on mainland systems. This is because there are no neighboring areas to net out impacts and because frequency excursions are much larger for similar sized imbalances. Adjusting the Hawaiian Electric reserve requirement to allow for potential deficiency of a few MW 1% or less of the time is not likely to adversely impact reliability.

As a hypothetical example, the segmented reserve requirement represented by the orange trace (in Figure L-3 for the GE study, and in Figure L-4 for the EPS method for the same Maui Electric PV ramping, and based on graphical observation without reviewing data) would likely provide 99.9% compliance for meeting its ramping requirements. Any imbalances would cause a deviation of less than one MW with little impact to frequency error.

Hawaiian Electric can further improve its reserve requirement approach by reviewing its operating criteria for the level of imbalance that can cause a significant frequency deviation, any added safety margins (to account for starting frequency), and its agreed upon risk tolerance (or compliance standard) on how often to allow deviations of different magnitude.

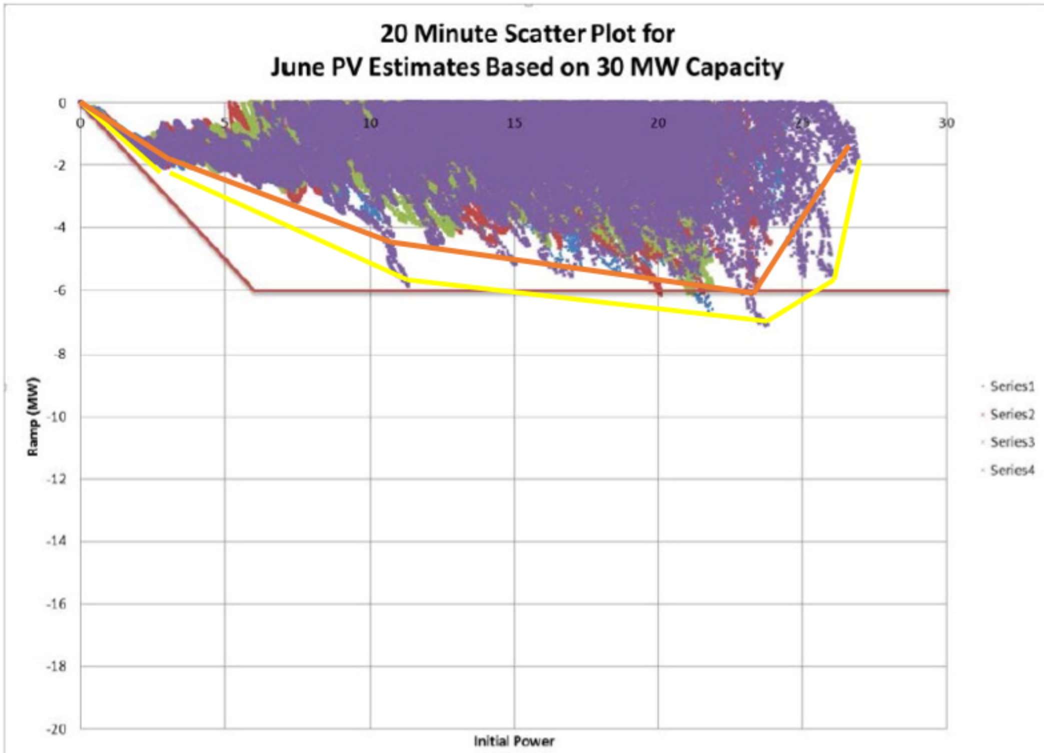

Figure L-3. GE Study Method 20-Minute Solar PV Ramp Rates: Segmented Reserve Requirement

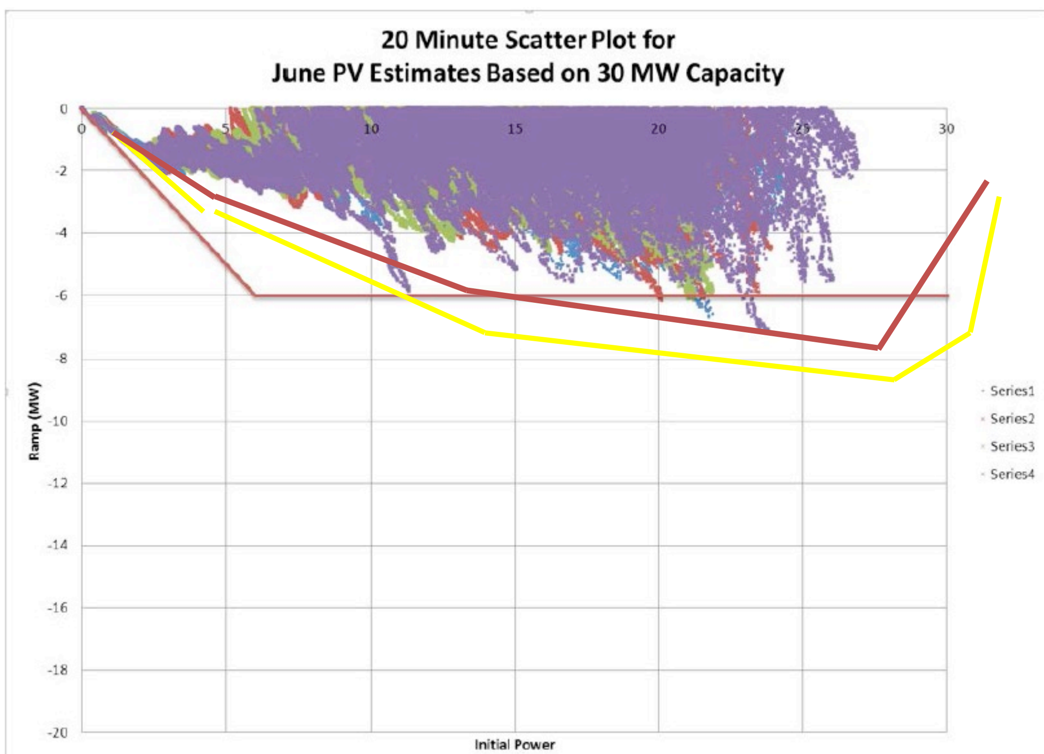

Figure L-4. EPS Method 20-Minute Solar PV Ramp Rates: Segmented Reserve Requirement

GE and EPS Improvement 4: Impact on the Predictability of Ramp Conditions

The GE study and EPS reserve methods determine regulation requirements based on the ramp levels of wind and solar at various output levels. They do not, however, consider the predictability of those ramps. The predictability (or unpredictability) of the ramp can have a large impact on the reserve requirement.

For example, solar ramp down during the evening is easier to meet compared to an unpredicted random cloud cover. Being able to predict the ramp allows operators to schedule to commit additional resources beforehand so that they are prepared to turn on when the ramp occurs. They might not, however, be needed during other periods.

Whether this impact can increase or decrease requirements is unclear. Clarity would depend on the accuracy of the renewable resource forecasts, and its scheduling efficiency (scheduling and commitment of resources outside of regulating resources).

RESERVE DETERMINATION METHODS THAT CONSIDER RENEWABLE OUTPUT

A number of other areas with high renewable penetrations are beginning to adjust their operating reserve requirements (mostly regulation reserve) to incorporate the impacts of renewables.

Although much larger than Hawaiian Electric, ERCOT is an isolated balancing area, although it has relatively small DC connection with other areas. ERCOT was one of the first regions that adjusted its reserve requirements based on renewable impact and kept a level of reserve that is not constant.

The following occurs in ERCOT's regulation reserve requirement methodology. ERCOT:

- Bases its regulation needs on meeting 95th percentile of all ramps by using data from the previous month and the same month in the previous year (for example, when calculating requirements for March 2016, they use mid-January to mid-February 2016 data and March 2015 data).
- Calculates requirements for each hour of the day in the following month, giving a 24-hour time series of requirements.
- Bases its regulation needs on meeting the NERC Control Performance Standard 1 that dictates how well it should balance generation and load
- Increases regulation due to wind generation by about 0.5% of installed capacity. For 1,000 MW capacity increase in wind, the regulation requirement is increased by 4–6 MW, based on the overall impacts on imbalance to the net load

- Bases the original level on previous deployments of the regulation, with regulation being used to meet overall net load imbalance

Other areas have described small changes to their regulation reserve requirements based on increased renewable penetrations. This typically includes regulation requirements that might be based on a percentage of load plus some quantity using the expected renewable output. Most of these are not as transparent as to how they are calculated compared to ERCOT. For example, SPP describes their regulation requirement as "based upon a percentage of forecasted load, adjusted up or down to account for resource output variability, and may vary on an hourly basis." The incremental requirements from wind generation are based on both the anticipated forecast and the anticipated hour to hour change.

Other areas on mainland U.S. are also introducing new reserve products, similar to regulation. These products, typically referred to as ramping capability or flexibility reserve, are reserve held to be used in a continuous basis (similar to regulation), but are deployed on a 5–10 minute time frame rather than a second-to-second time frame. The requirements are used primarily to accommodate for renewable forecast error and renewable output ramps. The requirements are typically based on historical renewable ramps over the time frame of interest (typically 5 minutes, 10 minutes, or 30 minutes), and expectation to meet some percentile of those ramp events (for example, 95%). These products are now present in areas including California ISO, MidContinent ISO, and Public Service of Colorado. Others may introduce similar reserve products in the near future.

References

These web links summarize some of these emerging requirements.

- EPRI, Reserve Determination Methods for Variable Generation: Industry Practices and the current research, Product ID 3002004242, October 2014.
- Ela et al., Operating reserve and variable generation, NREL tech report, 2011. http://www.nrel.gov/docs/fy11osti/51978.pdf
- ERCOT, Methodologies for Determining Ancillary Service Requirements. www.ercot.com/content/mktinfo/dam/kd/ERCOT%20Methodologies%20for%20Determining%20Ancillary%20Service%20Requir.zip (opens up zip file directly which contains word document)
- MISO, ramp capability white paper, 2013. https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Ramp%20Capability%20for%20Load%20Following%20in%20MISO%20Markets%20White%20Paper.pdf
- CAISO, flexible ramping product project page: https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

USE OF RENEWABLES FOR ACTIVE POWER MANAGEMENT

In many parts of the country and elsewhere in the world, renewables (wind and solar power) are used for various active power ancillary services to assist in meeting energy requirements and reliability needs. The description (with references) of two such services follows.

Service 1: Congestion Management and Redispatch

In many areas of the United States, wind power is used for redispatch to maintain the energy balance and ensure transmission constraints are within their normal and contingency limits. Most U.S. independent system operators use wind to assist in congestion management.

When a transmission constraint is limited and wind may be the most efficient or only option to bring the flow within limits, the system operator will send a direction to curtail the wind resource within the next five minutes. This can also be important when thermal generation plants are at their minimum stable generating limits where they cannot back down any further and cannot turn off because of their minimum off time and start-up times when required to be on in the near future.

Curtailing wind and/or solar could be an economic means to handle high penetrations, where it is less expensive to curtail than cycle units on and off. For example, Xcel Energy use this procedure in their Colorado service territory (which is a vertically integrated balancing authority) to allow them to turn off coal units. During nighttime periods, coal could be turned off and wind could provide AGC to manage variability. This may also reduce the amount of variability present in the system, either by reducing up-ramps of wind or solar (downwards reserve) or by pre-curtailing before periods of large ramp downs in wind or solar.

References

More information can be found in the following resources:

- NYISO, Integration of wind into system dispatch, 2008: http://www.ferc.gov/CalendarFiles/20090303120334-NYISO%20Wind%20White%20Paper%20October%202008.pdf
- MISO dispatchable intermittent resource program: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2011/DIR%20Workshops/20110413%20DIR%20Implementation%20Workshop%20Presentation.pdf

Service 2: Frequency Control

Wind power can provide frequency control (similar to the control of the turbine governor droop); it can respond rapidly to help stabilize frequency. Wind can also provide fast response, particularly to over-frequency events, by reducing impact (see Figure L-5). For sufficient under-frequency response, the wind facility has to be pre-curtailed, which may have economic or contractual consequences. If curtailed, wind can provide a fast response; in ERCOT, wind is required to do so only when curtailed for other reasons.

Solar is able to perform similarly. An accurate forecast of renewable output can also impact the ability of renewable generation to provide frequency response (particularly under-frequency response). When the forecast is inaccurate, the amount of frequency response from the renewable generation might be less than anticipated.

The controls to perform in this manner are readily available from the major wind turbine manufacturers, although they do need to be retrofitted to plants where they are not already installed. That said, having these controls enabled could potentially allow for other resources to be decommitted at times of high wind or solar output, when those resources can be curtailed to provide frequency response.

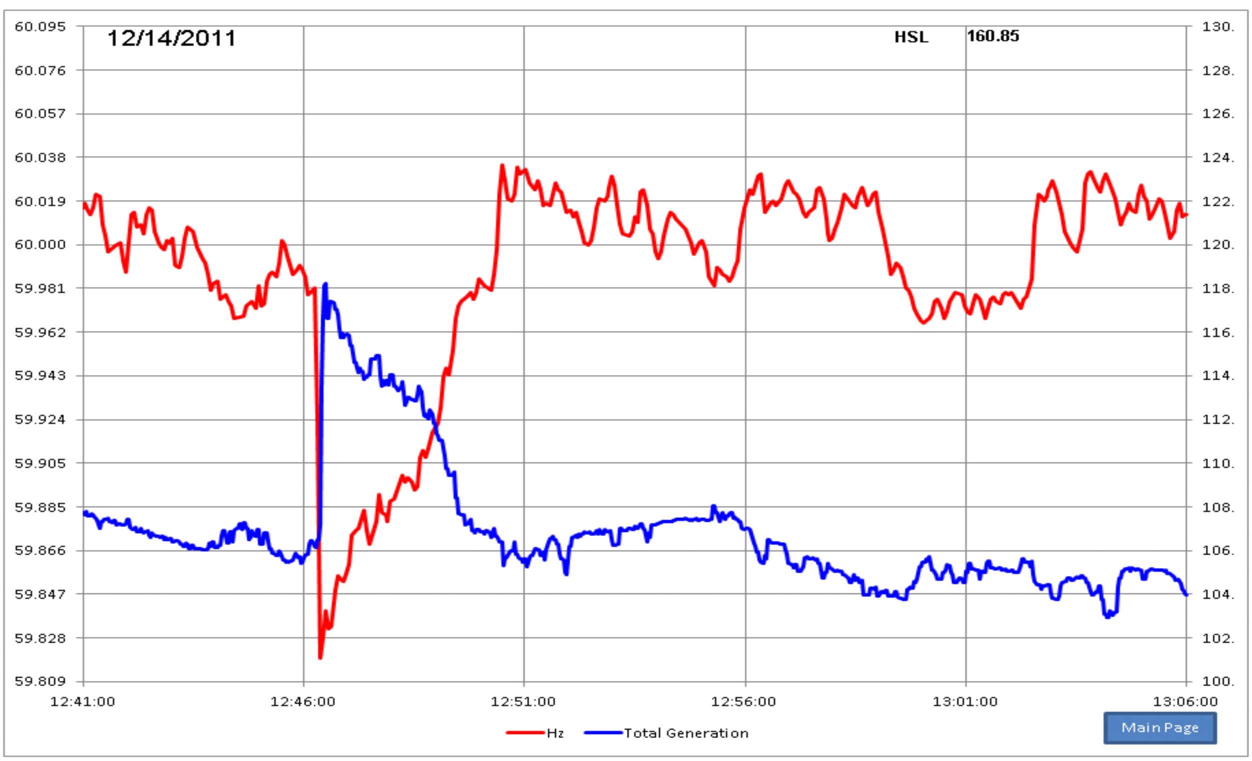

Figure L-5. Frequency Control Through Wind[1]

[1] Source: ERCOT website.

References

More information can be found in the following resources:

- http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-TRE-1.pdf (Reliability criteria in ERCOT that describes wind's participation in providing primary frequency control)
- http://www.nrel.gov/docs/fy15osti/64283.pdf
- EPRI and NREL organized a project, as well as associated workshops, on the above topics of active power control for wind. More details can be found at http://www.nrel.gov/docs/fy14osti/60574.pdf

M. Component Plans

To date, five Commission Orders have directed the Companies create a series of Component Plans. These Component Plans first appeared in Order No. 32053 for Hawaiian Electric, Order No. 31758 for Hawai'i Electric Light, and Order No. 32055 for Maui Electric. Order No. 33320 and Order No. 33870 reiterated this directive.

These Component Plans are:

- Fossil Generation Retirement Plan
- Generation Flexibility Plan
- Must-Run Generation Reduction Plan
- Environmental Compliance Plan
- Key Generator Utilization Plan
- Optimal Renewable Energy Portfolio Plan
- Generation Commitment and Economic Dispatch Review

Integrated throughout our planning and analysis, the Companies have worked toward satisfying the requirements stated in each of the Component Plans.

FOSSIL GENERATION RETIREMENT PLAN

Modernization Needs

Firm generating units that can be relied upon any time of day to provide power up to their nameplate capacity have historically been used to generate the bulk, if not all, of the energy needs for Hawaiʻi. As we move toward meeting the 100% RPS goal, many of these firm conventional generating units will be counted on less and less to provide energy because of increased levels of variable energy from photovoltaic (PV), wind, and other renewable power systems. This transition is already occurring, with variable generation providing a significant amount of the total energy needs for the Maui Electric and Hawaiʻi Electric Light systems. However, even after the state reaches its 100% renewable energy goal, firm generating units (operating on renewable fuels) remain essential components in the generating asset mix, albeit many of them having a different role than conventional generating units have today.

Although firm conventional units will gradually become less of the a primary energy source, they will provide supplemental resources: supplying customers' energy needs during periods with low variable energy production—periods with little sunshine, when the winds are calm, or during maintenance of large renewable assets. Firm generating units will also continue to enable reliable grid operation (for example, voltage stability and control, inertial response, and primary frequency response) and short-term balancing needs (such as replacement reserves). Of course, some types of firm renewable assets (such as biomass or geothermal) may continue to operate in a similar manner as historical conventional firm generation.

As the roles of firm generation assets evolve, the technical and operational capabilities of these units must match their new use pattern. To meet the future requirements, many existing generators must be modified or replaced to cost-effectively supply supplemental energy, fast balancing services, and other requirements identified for reliable and secure power delivery. Among other attributes, new assets need to have operational flexibility: the ability to start quickly, ramp up and down at high rates, and be designed to regularly start and stop multiple times daily even after long periods of being offline. Many existing firm generating units do not fully possess these characteristics. Often, newer generating units that bring more flexibility to the system will also provide improved fuel efficiency, resulting in lowering the amount of fossil fuel use while moving toward reaching the 100% renewable generation goal.

The timing of firm generation fleet modernization needs to consider several factors: the overall cost to customers for different resource options; objectives such as reducing fossil fuel use (which is different than meeting RPS requirements); and system resource needs for reliable and cost-effective operation, including whether existing aging units can continue to provide reliable service after years of operation.

While it may appear that new efficient generating units will lower fuel costs for customers, this is often not the case. Although less fuel will be used because of increased efficiency, the type of fuel readily available and authorized to use in new modern units is likely to cost more. Historically, the fuel cost premium has outweighed the efficiency gains such that overall fuel costs would have increased with the installation of new modernized generation. When the capital cost of the new generation is also taken into account, costs to customers increase even more. However, this would not be the case if a low-cost fuel became readily available that could be permitted for use in modernized generating units (such as LNG). If that were the case, it is possible that fuel cost savings could override the capital investment of new generation, thereby lowering overall cost to customers.

Whether or not modernized generating units will result in fuel cost savings, it is evident their installations would reduce overall fossil fuel consumption in our journey to 100% renewable energy production. Depending on the types of new generation assets installed and the existing technologies being replaced, new modernized generating units could be 20% to 50% more efficient. While this reduction in fossil fuel use is not the same as adding renewable energy resources, it accomplishes many of the same goals envisioned by the RPS directives. Over time, these new modernized generating assets will transition to use only renewable fuels, thereby reducing fossil fuel use even further.

The time lines for reduced use of resources as primary energy providers, and the need for the full slate of enhanced operational attributes that come with new modernized generating units can be estimated from analyses in the PSIP process. However, what cannot be easily determined is how long existing aging generating units can continue to operate reliably, particularly considering the changing use pattern. Until new generating units are installed, existing generation must have increasing operational flexibility and be subject to layup, cycling, and ramping for which they were not originally designed. There is also potential for increasingly stringent environmental regulations to make them too costly for continued service.

What is clear, however, is that firm generating resources cannot be considered for removal while they are still required to provide reliable and secure service to customers. In addition, even if units are not needed for reliability, a choice may be made to keep them in service if they continue to be cost-effective to operate and maintain.

We consider generating units for removal from service when all of the below are true:

- The cost of maintaining and operating the unit to provide bulk power needs is more expensive than an alternative means of serving bulk demand (for example, replacement generation is more economical, taking into account its capital cost, or the aggregate capacity value of variable renewable resources is sufficient to retire the unit).
- The unit is no longer required to meet adequacy of supply requirements (that is, providing capacity to meet reserve margins).
- The unit is not required for system security reasons (such as offline reserves, fast-start, system restoration, or other critical functions) or is not the most economical means of meeting system security (for example, when a different generator, BESS, or DR can provide a more economical source of these essential grid services).

Weighing factors of cost, need for greater flexibility, and maintaining reliability, the PSIP plans include dates to add new generation resources. In some cases, these additions will increase costs to customers but are prudent to continue providing reliable service for the changed operational and technical requirements of the generation fleet.

The plan to add new generation resources creates potential to remove from service existing generating units. This does not necessarily mean that we will remove generation units from service on the identified dates. We may adjust dates based on further optimization taking into account actual fuel costs and resource availability at the time of the decision, and on the timing of proposed renewable energy and firm dispatchable additions. A case-by-case evaluation will determine whether an existing unit will be immediately retired, deactivated, used for seasonal cycling, or kept operational. The goal is to manage these assets in a manner that provides maximum value for customers. If removal from service is enabled through addition of new resources, a period of time for the new resource to become reliable and proven will be accommodated before removal of existing assets, if practical.

Hawaiian Electric's Plan for Retiring Fossil Generation

Hawaiian Electric owns and operates 12 steam generating units ranging in age from 35 years to 69 years. All of these steam units are currently needed to meet adequacy of supply criteria used for the O‘ahu grid. Therefore, they need to remain operational until and unless new resources are installed that replace the capacity and ancillary services these steam units provide.

Technically, these steam units could operate indefinitely as long as maintenance and repairs are continued, which do have associated costs. To date, financial analyses taking into account these costs typically show it is still cost effective to keep the steam generating units operating as long as they use a lower cost fuel than potential replacement generation.[1] However, it is not realistic or practical to plan for an indefinite lifespan of these older generating units for several reasons.

The capacity represented by the Hawaiian Electric steam units is necessary to reliably meet the energy needs of O'ahu. As units age, unforeseen and unpredictable problems will arise more frequently, unless substantial capital renewal investments are made. This will be exacerbated by the expected operational profile (for example, offline cycling and potential intermittent periods of shutdown) will exacerbate this issue as the grid rapidly transitions to high penetration levels of variable renewable energy. The steam units are best suited for steady state, base load operations, not frequent ramping and cycling. These factors will lead to more frequent unplanned outages, which unlike planned outages can occur when the system does not have enough reserve capacity to reliably satisfy the island electricity demand. As the units age, there is increasing likelihood of unit outages resulting in generation shortfall.

The operations of the steam units will substantially change with the incorporation of increasing renewable energy, requiring flexible operation to supplement variable and renewable resources. Although measures have been taken to increase the flexibility of the steam units to allow higher penetration levels of variable renewable energy, these generating units cannot achieve the flexibility of other types of generation designed for offline cycling, fast start, and fast ramping. Meeting system needs may require adding new generating resources with these operational and technical capabilities , thereby rendering some of the existing units unnecessary. If this occurs, a case-by-case analysis would determine if certain existing steam units should be kept operational, used for cycling, deactivated, or decommissioned.

In addition to other factors, the steam units are subject to existing and future environmental regulations and requirements. Federal environmental regulations are intended, over time to prevent the degradation of air quality by requiring older, higher emitting electric generating units to retire or to install state of the art emissions controls. It is possible that environmental regulation considerations may require Hawaiian Electric generating unit changes (such as a switch to a higher cost fuel, or equipment retrofits, or costly environmental controls). If environmental considerations require a significant investment or change to higher-cost fuels, it is likely that replacement generation options would then be cost effective.

Recognizing these issues, we established dates by which we believe it will be prudent to install new generation resources, which also facilitates potential removal from service of

[1] The steam units use a #6 low sulfur fuel oil (LSFO), while new units are assumed to use readily available diesel fuel because environmental regulations would not allow them to use LSFO. Since the year 2000, diesel fuel prices were approximately 34.5% higher than LSFO on average.

identified existing steam units. The governing philosophy in setting these dates was to minimize and spread out increasing costs to customers while at the same time ensuring installation of new generating units prior to experiencing major reliability issues with existing assets. Identifying dates also allows us planning for ramped-down maintenance on individual units, which typically starts six years prior to planned removal dates.

Based on assumed asset additions in the various resource plans, Table M-1 shows the corresponding dates for which O'ahu's steam units can be considered for service removal.

Date	Post April PSIP Plan	E3 Plan with Generation Modernization	E3 Plan with LNG and Generation Modernization
2022	AES*	AES*	AES*
2023	Waiau 3 & 4	Waiau 3 & 4	Waiau 3 & 4
2024	–	–	–
2025	Kahe 6	–	–
2026	–	Waiau 5 & 6	Waiau 5 & 6
2027	Kahe 1 & 2	–	–
2028	–	Kahe 5 & 6	Kahe 5 & 6
2029	–	–	–
2030	Waiau 5 & 6 Kahe 5	–	–
2031	–	Waiau 7 & 8	Waiau 7 & 8
2032	Waiau 7 & 8	–	–
2033	–	–	–
2034	Kahe 3 & 4	–	–
2035	–	Kahe 1 & 2	Kahe 1 & 2
2036	–	–	–
2037	–	–	–
2038	–	–	–
2039	–	Kahe 3 & 4	Kahe 3 & 4

* Technically, AES isn't being retired; we are allowing its Power Purchase Agreement (PPA) to expire without renewal.

Table M-1. Hawaiian Electric Generation Firm Generation Removal from Service Plans

To provide the most cost reduction to the customer, we plan to remove units in unit pairs because they share one control room, operator staff, and common equipment. The existing combustion turbine units, Waiau 9 and Waiau 10, are not in this removal plan because their design provides the type of flexibility needed in the future high as available renewable environment. However, these units are currently 43 years old and it may be prudent to replace them during the PSIP planning period. Ongoing reliability of these units and the cost to maintain that reliability will be measures of whether their replacement should be included in future plans.

Hawai'i Electric Light's Plan for Retiring Fossil Generation

Historically, steam units provided the bulk of the island energy needs. As capacity needs increased, gas turbines and combined cycle resources were incorporated onto the system. These resources are more flexible and efficient than the steam units, but use a fuel which often costs higher than that used in the steam units. Hawai'i Electric Light owns and operates three steam generating units ranging in age from 46 years to 51 years. Currently, the steam units are in active operation as it is cost-effective for them to remain so. This is because the current cost of the fuel used in the steam units results in lower production cost than other energy resource options. When and if the fuel economics change to where it is no longer cost-effective to operate and maintain the steam units, and they are not needed for system reliability, the units will be removed from service. They would then follow a transitional plan prior to consideration for retirement, assuming the cost of maintaining and operating the unit to provide bulk power needs is not cost-effective at the time of the decision, the unit is not required for adequacy of supply, and the unit is not required for provision of reliable service. Adequacy of supply requires at least one of the steam units be kept available until additional capacity is added to the system.

While increasing flexibility is required from firm generation as variable resources increase on the system and larger conventional plants are displaced from operation, Hawai'i Electric Light has a significant amount of flexibility with its existing fast start diesels and simple-cycle combustion turbines. The diesels and simple-cycle initially provided fast-starting replacement reserves to restore under frequency load-shed customers and support short-term energy needs, and have proven useful in managing system balancing with a high penetration of variable renewable resources. Therefore, it is not a near-term priority to add new flexible generation to accommodate variable renewable generation.

However, these diesel engines and simple-cycle combustion turbines range in age from 19 years to 54 years. As such, it may be prudent to replace some of these assets during the 29-year PSIP planning period. Ongoing reliability of these units and the cost to maintain that reliability will be measures of whether their replacement should be included in future plans.

Table M-2 shows the units considered for removal from service and the corresponding dates. While the E3 plans identify CT2 in 2040, this is the black-start resource for system restoration located in West Hawai'i and its removal from the system would require addition of another West Hawai'i resource capable of being similarly used to restore the system from total outage. That would require a resource capable of remote startup by the System Operator without station power and operating in isochronous (local frequency control) mode. A black start resource must be capable of meeting load-changes occurring during cold load pickup and transformer inrush currents. An option could be to add a black-start diesel to Keahole sized to support startup of CT4 and/or CT5 without reconfiguration of auxiliary loads (the CT2 black-start diesel is not large enough).

Date	Post April PSIP Plan	E3 Plan	E3 Plan with LNG	E3 Plan with LNG; Keahole & HEP LNG Conversion
2020	–	Puna Steam Hill 5 & 6	Puna Steam Hill 5 & 6	Puna Steam Hill 5 & 6
2021	–	–	–	–
2022	–	–	–	–
2023	–	–	–	–
2024	–	–	–	–
2025	Puna Steam	–	–	–
2026	–	–	–	–
2027	Hill 5	–	–	–
2028	–	–	–	–
2029	–	–	–	–
2030	Hill 6	–	–	–
2031–2039	–	–	–	–
2040	–	CT2*	CT2*	CT2*

* CT2 cannot be retired until replacement black-start resource is added to West Hawai‘i.

Table M-2. Hawai‘i Electric Light Firm Generation Removal from Service Plans

Maui Electric Retirement Plan

The four steam units at the Kahului Power Plant (KPP) will be retired upon the installation of replacement generation capacity on Maui along with upgrades to the transmission system no later than November 30, 2024 (discharges to receiving waters cease after that under the KPP National Discharge Elimination System permit), whichever occurs first. Current plans are to have the new capacity and transmission upgrades in place by December 31, 2022.

While increasing flexibility is required from firm generation as variable resources increase on the system and larger conventional plants are displaced from operation, Maui Electric has a significant amount of flexibility with its existing fast start diesels and combined-cycle combustion turbines. Additionally, the intent is for new generating assets installed as replacement capacity for KPP and to satisfy near-term load growth to have high levels of flexibility. Therefore, it is not a near-term priority to add new flexible generation for the sole purpose of accommodating variable renewable generation.

However, these diesel engines and combined-cycle combustion turbines range in age from 18 years to 65 years. As such, it may be prudent to replace some of these assets during the PSIP planning period. Ongoing reliability of these units and the cost to maintain that reliability will be measures of whether their replacement should be included in future plans.

Table M-3 shows Maui Electric's schedule for removing existing fossil fuel generating resources from service.

Date	Post April PSIP Plan	E3 Plan	E3 Plan with LNG
2022	Kahului 1–4	Kahului 1–4	Kahului 1–4
2023	–	–	–
2024–2044	–	–	–
2045	–	Ma'alaea 4–13	Ma'alaea 4–11

Table M-3. Maui Electric Firm Generation Removal from Service Plans

Background

KPP consists of four steam units totaling 35.92 MW (net) firm generating capacity with units K1–4 installed in 1948, 1949, 1954, and 1966 respectively. When operating, these units provide firm generation and contribute to system security by providing regulating reserve, system inertia, and voltage support.

In May 2013, the State of Hawai'i Department of Health (DOH) advised Maui Electric of new requirements relating to cooling water discharge at KPP, impacting its National Pollution Discharge Elimination System (NPDES) permit. As a result, Maui Electric anticipated it would have to retire KPP by 2019, before having to meet the new cooling water discharge requirements, or implement a solution that would meet NPDES standards. This was reflected in the 2014 PSIP.

In late 2014, Maui Electric chose to pursue a 9.5-year compliance plan to be included in the NPDES permit. Including the compliance plan allows Maui Electric to continue operating KPP beyond 2019, and provides more time to secure replacement capacity and complete the necessary transmission upgrades in Central Maui. The NPDES permit containing the 9.5-year compliance plan was approved in June 2015, giving Maui Electric until November 2024 to cease water discharges at KPP, effectively requiring that KPP be retired at that time.

Potential alternatives (which would likely require modifying the existing NPDES permit) to terminating the discharge of water from KPP (such as a cooling tower, deep ocean discharge, and injection wells) all face a multitude of barriers (permitting, property acquisition, and easements) that would jeopardize their ability to be completed before the expiration of the NPDES permit. Indeed, given the discretionary permits as well as the cooperation and coordination from other landowners, it is questionable whether these solutions could be implemented at all.

Other Considerations

In addition to addressing the concerns of the Commission regarding the curtailment of wind energy and meeting environmental requirements, other factors further solidified Maui Electric's decision to retire KPP. They include:

Tsunami Mitigation: Given its location along the Kahului shoreline, KPP is very susceptible to damage should Maui be impacted by a tsunami. As the need arises and is appropriate, Maui Electric will replace generating assets with generating facilities out of the tsunami inundation zone that will make the Maui grid more resilient against such a natural disaster.[2]

Renewable Energy Integration: The reduction to base load generation on Maui associated with retiring KPP and termination of the HC&S PPA will provide additional headroom for accepting variable renewable energy. Quick starting units will be sought as part of the solution to replace KPP's generating capacity, allowing greater operational flexibility.

Replacement Generation

Absent any replacement capacity, the retirement of KPP will result in a reserve capacity shortfall of at least 40 MW. Meanwhile, system peaks on Maui have been trending upward, driving the potential need for even more future capacity. To ensure adequate generating capacity for Maui's customers, Maui Electric, on May 5, 2016, requested the Commission open a docket to initiate procuring the necessary capacity.

A portion of the replacement capacity is planned to be located in South Maui to address that area's existing under-voltage risks. The generation would serve as a non-transmission alternative (NTA) to upgrading the transmission line serving South Maui. (The upgrade has received significant community opposition because of the aesthetic impact of upgrading the line.)

Our planning process considered a number of options for the replacement capacity for KPP. Ultimately, the resource will be selected based on the option that provides the best value to Maui Electric's customers.

Besides procuring replacement capacity, Maui Electric will continue to pursue non-generation alternatives to help meet the island's capacity needs, while minimizing future traditional generation. These alternatives include, but are not limited to, demand response, time-of-use rates, and energy storage. As a temporary near term measure, Maui Electric has begun the procurement of just under 5 MW of DG to be located at the Kuihelani substation in central Maui. An application for approval for the DG units was submitted in September 2016 to the Commission.

[2] Both KPP and Maʻalaea Power Plant are located in the tsunami inundation zone. As a result, the threat of damage from a tsunami plays in a role in Maui Electric's decisions on where to locate future generation or other assets.

Central Maui Transmission and Distribution Project

The Central Maui region plays a critical role on the island of Maui as it is the center of government and commerce. The Central Maui region is served by both the 69kV system and the 23 kV system with power provided by the Ma'alaea Power Plant (MPP) and KPP. The KPP retirement primarily impacts the 23kV system, which serves the areas of Kahului, Wailuku, and Wai'ehu. Over 13,000 Maui Electric customers are on the 23 kV system, including University of Hawai'i Maui College, Baldwin High School, Maui High School, Maui Mall, Community Clinic of Maui, Armory Reserve, Maui Arts & Cultural Center, Hale Makua, Maui Beach Hotel, Maui Sea Side Hotel, Wallace Theaters, Maui VET Center, War Memorial Stadium, Nan Inc., Sack N Save, Foodland, Young Brothers, State of Hawai'i Department of Transportation Harbors Division, County of Maui water facilities and waste water treatment pumps, Central Maui Landfill, and Ameron. It is imperative to continue to provide reliable, electrical services to this area.

After retiring KPP, the Central Maui load on the 23 kV system will be served primarily by MPP, and the Kaheawa and Auwahi windfarms via the capacity-constrained MPP–Waiinu and MPP–Kanaha 69 kV transmission lines. The 69kV transmission lines serving Central Maui need to be modernized and upgraded to ensure continued system reliability for the Central Maui region. In addition, the 23 kV system in Central Maui has three 69/23 kV transformers that connect the 23 kV system and the 69 kV system. These transformers are located at Waiinu, Kanaha, and Pu'unene substations. The loss of either the MPP–Waiinu 69 kV or the MPP–Kanaha 69 kV transmission lines (that is, defined as a N-1 contingency) during higher system load conditions results in under voltages and thermal overload conditions.

Under these contingencies, there is the potential for overloads to occur on the remaining transformers, depending on the load. If too much power is being transferred to the 23 kV system from the 69 kV system, the system may not be able to manage the transfer and could experience a voltage collapse and/or load shedding scenarios if further system disturbances or unanticipated load increases in the Central Maui region occur. To support the retirement of KPP and as part of grid modernization efforts, Maui Electric is proposing to upgrade the existing 23 kV Waiinu–Kanaha line to 69 kV (which includes 69 kV upgrades to the existing Waiinu and Kanaha substations). This is a major addition to the existing Kahului Substation, and a reconductoring (that is, increasing the transmission line capacity) of the existing MPP–Waiinu and MPP–Kanaha 69 kV transmission line.

These upgrades address the required N-1 Transmission Planning criteria, maintain required voltage limits, strengthen and complete the critical 69 kV link for Central Maui, and allow for continued and reliable service under contingency conditions (that is, during system maintenance and forced outages) and higher system loads.

The Kahului Power Plant Retirement-Comprehensive Assessment (included in the 2014 Maui Electric PSIP) provides the technical analysis to locally reduce the amount of load and help with the voltage issues on the 23 kV system. In addition to upgrading the transmission system, we considered NTAs such as internal combustion distributed generation (DG), battery energy storage system (BESS), and synchronous condensers. The analysis, however, concluded that upgrading the transmission and distribution system is the most technically sound and viable option.

To more thoroughly investigate NTA options, a third-party NTA study was conducted in a joint effort by the engineering and planning firms of Tetra Tech and CH2M Hill. The NTAs assessed included:

- Firm dispatchable distributed generation (FDDG): similar to conventional generation, available to the utility for immediate dispatch
- Dispatchable standby generation (DSG): emergency generators
- Photovoltaic and battery (PV/battery): combination
- Firm dispatchable generation/battery energy storage systems (FDG/BESS)
- Synchronous condensers
- Static capacitor banks
- Demand response (DR)

The Tetra Tech/CH2MHill report identified FDDG as the only feasible non-transmission alternative that would effectively address the contingency overload and under voltage conditions in Central Maui. The Tetra Tech/CH2MHill report concluded that the only NTA that addresses the loss of generation from KPP, supports voltage stability, and prevents thermal overloads is the addition of new FDDG on the 23 kV system strategically located to serve the Kahului, Waiinu, and Wailuku areas. A potential site was identified in the Central Maui area; however, the County of Maui indicated that it does not consider FDDG in the Central Maui region as a viable NTA citing noise, traffic, and emissions concerns. Similarly, a major real estate developer noted their concerns with the placement of FDDG in the Central Maui area citing impacts to future residential development plans.

In addition, the FDDG option requires major transmission line upgrades from the FDDG to the existing transmission system, as well as a redundant transmission line tie-in (to address the N-1 criteria) to the existing 23kV system. Without the NTA/FDDG option, Maui Electric will need to upgrade the existing 23 kV system.

As part of the project analysis, a NTA Business Case was conducted by Accenture and it recommends the CMTD Project as it provides the highest Benefit Cost ratio and provides greater engineering certainty. Based on stakeholder input, a secondary NTA Business

Case will be initiated in first quarter 2017 and is targeted for completion in second quarter 2017. The secondary NTA Business Case will review NTA system level and ancillary benefits, factor in the costs of environmental permitting, land, transmission line and substation interconnection costs (based on location), as well as integrate a risk analysis component.

Based on technical and Business Case analyses completed to date, the Central Maui Transmission and Distribution project (CMTD) provide the most certain path toward ensuring continued reliability and operational flexibility in the Central Maui area. From a cost and technical solution standpoint, other NTA options are more uncertain regarding the potential to provide the necessary remedies before retiring KPP.

The CMTD project is currently in the detailed planning, engineering, and permitting phase, and the Environmental Impact Statement (EIS) process is currently underway with construction scheduled to start in early 2020.

Completing the CMTD and acquiring replacement generation capacity are both targeted for completion by the time KPP is scheduled to retire in 2022. Given the magnitude and complexity of both of these projects, the target KPP retirement date provides a prudent amount of schedule flexibility ahead of the 2024 expiration of KPP's NPDES permit.

GENERATION FLEXIBILITY PLAN

Hawaiian Electric: Increasing Operational Flexibility of Existing Steam Generators

Hawaiian Electric has implemented a number of initiatives to improve the flexibility of the existing base loaded steam units. The approach reviewed procedures and policies, past studies, and industry guidance. More specifically, instead of just identifying projects that would enhance flexible operations, Hawaiian Electric asked these questions for our evaluation:

- What type of operational needs does the system need?
- What can existing generation do to meet those needs in the short term?

  Some operations will have long term consequences. However, these consequences could be insignificant if plans for modernized generation are implemented.

- What are the limiting factors that prevent such operations?

  Some factors are technical. What can we do to modify operations, procedures, etc. to avoid hitting technical limits?

- Do new or current system conditions make old limitations and policies obsolete? What practices, policies, rules can be modified to support flexible operations.
- What projects can be implemented to enhance, support, or improve flexible operations? Or, if necessary, what projects are necessary to make flexible operations possible (issues that could not be resolved with attempts asked above).

In response to these issues, Hawaiian Electric focused on improving flexibility in the following areas:

- Low load operation (improving turndown)
- Ramp rate improvements
- Developing a process to cycle reheat units on and offline

Enhanced Low Load Operation

Hawaiian Electric validated low load operations and looked for areas of improvement. During discussions and problems solving events, the company realized that if it could lower unit load even further than initially expected, it could provide nearly the same system benefit as cycling operation, in terms of allowing more variable generation, and at the same time provide system reliability services while minimizing cycling wear and tear on the units.

From that point, the company researched what is the lowest load that the turbine and generators could safely support. From there, what operational practices would need to be changed in order to achieve such low load?

Hawaiian Electric quickly learned that a realistic enhanced low load of 5 MW gross[3] was possible and has various benefits over on and off cycling.

- Results in 2-3MW of net generation. Nearly the same as being offline.
- Less thermal cycling of plant components.
- Will provide ancillary services to the system:
- Response to system disturbances
- Frequency regulation
- Quicker restoration compared to cycling
- Voltage support
- Short circuit current
- Depending on the duration of operation, burns the same or less fuel as a unit cycling on and offline.

Following the June 2014 test on Kahe 3, Hawaiian Electric focused on establishing testing schedules and procedures for operating the small reheat units at new low loads. The low load targets were set at 5 MWg.

Again, Hawaiian Electric took a holistic approach to the low load operation. For example, Hawaiian Electric had a long-standing policy to always operate with all burners in service. The requirement was based on maintaining the ability to pick up load and respond to system disturbances. After analyzing those requirements, the company determined that system conditions are now different and the customer is best served by modifying the existing policy and procedures.

In other cases the company examined the technical limits. Steam and turbine metal temperatures had historically been limiting factors. The department explored, tested and implemented a new operating control called hybrid variable pressure operation (VPO). In true variable pressure operation, the boiler and throttle operating pressure is reduced until the turbine governor valves are wide open. Changes in load are then accomplished by changing boiler and throttle pressure.

This type of control has the benefit of improving efficiency and helps minimize thermal stresses on the turbine. However, this type of control is not proper for the Hawaiian Electric system as the units respond to slowly to changing demands or system upsets.

[3] Gross MW includes generation used to supply the unit's own electric load. Net load refers the actual export to the system.

With the "hybrid" approach, Hawaiian Electric operates at normal boiler and throttle pressures above 30 MW. When asked to reduce load to less than 30 MW, the Department slides boiler and throttle pressure linearly as load drops. This mode of operations allows the Department to maintain current operating characteristics at normal operating loads but allows the unit to achieve new lower loads while meeting required turbine operating parameters.

The low load operation has the various benefits previously described and has greatly enhanced the ability to add variable generation to the system. Table M-4 shows the magnitude of difference.

Unit	Normal / Historic Low Load	Enhanced Low Load	Change in Minimum Load
Kahe 1	30 MW	5 MW	25 MW
Kahe 2	30 MW	5 MW	25 MW
Kahe 3	30 MW	5 MW	25 MW
Kahe 4	30 MW	5 MW	25 MW
Waiau 7	30 MW	5 MW	25 MW
Waiau 8	30 MW	5 MW	25 MW
Total Reduction in Hawaiian Electric Minimum Load[4]			150MW

Table M-4. Hawaiian Electric Total Reductions in Minimum Loads

On/Off (Daily) Cycling

Hawaiian Electric also examined the cycling of reheat units. As mentioned, the initial test in June 2014 was an online/offline cycling test. During that test the Department proved that "hot" cycling of the small reheat[5] units could be performed daily, and that the units could start reliably daily. Total start time from initial fires to firm generation is approximately 3.5 hours. Longer shutdowns, such as weekends, result in longer starts.

Hawaiian Electric believes that the focus and immediate needs are best served with the enhanced low load operation for the reasons previously discussed and that is where the focus to date has been. With that said, Hawaiian Electric is confident in the ability to cycle the small reheat units if it becomes necessary. The ability to cycle will revolve around procedure enhancement and practicing shutdown and startup techniques to minimize thermal stresses. The ability to properly estimate when the unit will return to service allows establishing shutdown conditions that minimize startup time and stress. Some unit modifications are being considered to facilitate cycling and improve long term reliability. These projects are not necessary to cycle in the short term but would facilitate

[4] Based on theoretical operation of all six units at new enhanced minimum load. Other system requirements, such as system ramp rates, may or may not allow for all six units to operate simultaneously at the new enhanced low loads.

[5] Kahe units 1–4 and Waiau units 7 and 8 are considered small reheat units. Kahe units 5 and 6 are considered large reheat units.

such operations over time. Projects are to be considered based on benefit, cost, and in consideration of the generation modernization plan.

Hawaiian Electric estimates that the breakeven point between enhanced low load operation and cycling is about five hours based on fuel expenses alone and depending on the specific unit. The breakeven point would be longer than five hours when including maintenance cost and reliability issues.

Consequences of Low Load Operation and Cycling

Operation at the enhanced low loads does have some consequences. Operationally, the unit is not immediately available for full load operation. With the boiler/throttle pressure reduced and multiple burners out of service the unit needs time to restore to full capabilities. Based on boiler and throttle pressure ramp rate limits the restoration time is 1.5 hours. However, the unit is available for increasing amount of load throughout the recovery period.

Ramp rates are also affected. While operating at the enhanced low loads the units can ramp at the traditional ramp rates but not the new, higher ramp rates achieved as part of the flexible operation initiative discussed in the following section.

In addition, it is expected that maintenance cost will eventually rise do to the cyclic thermal and pressure stresses. However, these thermal and pressure cycles are smaller than if the unit was to be cycled on and offline. Nonetheless, industry evidence shows that maintenance cost associated cycling or larger load following events is expected to increase.

Future maintenance costs are also expected to be measurably higher with enhanced low load or cycling operation. Enhanced low load and cycling operation causes increased pressure and temperature cycling on boiler and turbine pressure components. These cycles increase both in terms of frequency and magnitude. These increased stress cycles result in damage from corrosion fatigue, thermal and mechanical fatigue, creep, stress corrosion crack, and others. For example, hot starting a reheat unit results in thermal quenching of the economizer. In addition, some valves will have increased wear from cycling operation. For example, boiler feed regulating valves and boiler feed pump recirculating valves are expected to have higher maintenance cost associated with increased use at the extremes of their design. With more operation with lower mass flow through the boiler, boiler tube deposition and associated failure events are expected to increase. Essentially, increased flexibility provides immediate benefits to the system but will result in future increases in maintenance expenses.

It should be noted that heat rate (efficiency) is poor during the enhanced low load operation. Generally heat rate is higher the lower the load. However, due in large part to

National Fire Protection Association (NFPA) requirements regarding minimum boiler air flow, heat rate increases exponentially below about 25 MW. This high heat rate affects the system LSFO heat rate.

Cycling operation also affects the heat rate of the units. The fuel used for startup operation causes measured heat rate to increase. Increasing the number of starts on the reheat heat units will also affect system LSFO heat rate.

Ramp Rates

Hawaiian Electric has also worked to improve the ramp rates[6] of existing generating units. Power Generation had previously tested higher ramp rates. Based on that testing and an understanding of equipment limitations, the following ramp rate improvements were made:

Unit	Old Normal Ramp Rate (MW/Minute)	Future Normal Ramp Rate (MW/Minute)
Kahe 1	2.3	4.0
Kahe 2	2.3	4.0
Kahe 3	2.3	5.0
Kahe 4	2.3	5.0
Kahe 5	2.5	4.0
Kahe 6	2.5	4.0
Waiau 7	3.0	4.0
Waiau 8	3.0	4.0
Waiau 3	0.9	0.9
Waiau 4	0.5	0.5
Waiau 5	3.0	3.0
Waiau 6	3.0	3.0
Total	27.6	41.4

Table M-5. Hawaiian Electric Ramp Rate Improvements

The table above represents a 13.8 MW per minute[7] improvement of steam plant ramp rates. These improved ramp rates represent the ability existing units to respond to changes in wind and or solar generation. The ramp rates for the cycling units were not changed. Waiau 3 and 4 are of an age and material condition that does not support increasing ramp rates. Waiau 5 and Waiau 6 have high ramp rates as a percentage of their size.

[6] Ramp rate is the rate at which generator load can be changed, measured in MW/min.

[7] Assuming all listed units were online at their normal operating modes. During most operating periods all units are not online and increased amounts of variable generation will likely result in more units offline or operating in hybrid variable pressure operating mode.

Kahe 3 and Kahe 4 have modern turbine control systems. This modern control system allows them to operate in what is referred to as "coordinated control". In this operating mode the turbine and boiler operations are coordinated and allow for improved control of the unit with higher ramp rates. Kahe 1, Kahe 2, and all the Waiau units operate in "boiler follow" mode. In this mode the turbines respond to demand. The boiler control system senses a change in pressure and fires up/down to correct the pressure variance. In this mode, larger ramp rates challenge the control systems abilities to increase load while maintaining environmental compliance. For that reason they will have a lower ramp rate than Kahe 3 and Kahe 4. Kahe 5 and Kahe 6 turbines have an old analog control system that does not easily accommodate coordinated control and therefore the units also operate in boiler follow.

It should be noted that the new higher ramp rates do not apply while operating in enhanced low load mode. The benefits of the ramp rate improvements only apply at normal operating conditions.

Conclusion

Flexible operations improvements are critical for the short term ability to adapt and support increased levels of variable generation. Photovoltaic systems have already impacted day time operations. The daily load profile has been altered by the amount of variable penetration on the system during the day. In 2016 there were numerous occasions where one or more small reheat units were dispatched to the enhanced low loads during morning and afternoon hours. Likewise, there were a number of occasions where one or more small reheat units were dispatched to the enhanced low loads during overnight hours to avoid curtailment of wind. As the magnitude of variable generation increases the existing Hawaiian Electric generators will continue to play an important part in maintaining system reliability and stability.

These new operating improvements will not come without cost. Future maintenance costs are expected to rise as the units experience increased amounts of thermal and pressure cycles. These operations are considered short term solutions until better-suited, modernized generation can replace the existing generating units.

Maui Electric Generation Flexibility Plan

Maui Electric has implemented many changes in our generation fleet to increase flexibility and renewable integration. These have previously been described in our System Improvement and Curtailment Reduction Plan (SICRP) and subsequent annual updates. These changes included:

- Implementing the Maui Operation Measures.
- Reducing the number of baseload units.
- Reducing prior run times of KPP units 1 and 2.
- Lowering of the minimums on KPP units 3 and 4.
- Studying and implementing new regulating reserve requirements.
- Automating curtailment though our Automatic Generation Control (AGC) system.
- Low load modifications to DTCC 1.

The existing Maui Electric generation fleet has operating characteristics that are quick starting, flexible, fuel-efficient, and dispatchable to accommodate the integration of existing and additional variable renewable energy resources without significant curtailment.[8] Quick-starting generation has the ability to remain offline until it is required to support the system (such as during a large down ramp event when the wind or solar resources suddenly become unavailable). Other units that may need additional time to start and connect to the system will need a resource to bridge the time required to supply generation (for example, demand response and energy storage). Flexible generation refers to units that can be held offline until called upon for generation, allowing us to maximize variable renewable generation.

Roles of Current Generation

Kahului Power Plant. Kahului Power Plant consists of four steam units (K1, K2, K3, and K4) that provide firm generation, regulating reserve, system inertia, reactive power and voltage support for Central Maui, and is the primary source of fault current for the 23 kV system. These units burn an industrial fuel oil that is lower cost than diesel. K1 and K2 units were deactivated on February 1, 2014, however, they have been taken off deactivated status in 2016 due to system needs.

Maʻalaea Power Plant. Maʻalaea Power Plant has two dual-train combined cycle units (DTCC1 and DTCC2). These units provide firm generation, regulating reserve, and system inertia, and can start and provide generation in a relatively short time period. When operated in the dual-train combined cycle configuration, these units are the most efficient generating resources on Maui. DTCC 1 is a must-run generating unit that

[8] The thermal generation fleet on Lanaʻi and Molokaʻi is comprised of flexible, quick-starting units.

contributes to system security. Modifications are in progress and planned to be completed in January 2017 to allow it to operate at a lower capacity minimum level. This will allow more opportunity to integrate variable renewable energy when available. DTCC2 was changed from a baseload unit to a unit that can be operated in combined cycle or simple cycle mode when there is a capacity need or when renewable energy is not available.

Ma'alaea Power Plant also has fifteen internal combustion diesel units (MX1, MX2, M1, M2, M3, M4, M5, M6, M7, M8, M9, M10, M11, M12, and M13). These units provide firm generation and regulating reserve. These units can start and provide firm generation in a relatively short time period. Five of these units (MX1, MX2, M1, M2, and M3) are quick-starting units that can be used for emergency and as a transition unit to starting a larger diesel unit. (MX1, MX2, M1, M2, and M3 units do not contribute regulating reserves when they are online because they run at top load). These units will remain offline and be available for contribution to system security and system load as needed after other offline non-fossil fuel resources (such as DR and energy storage) have been used to its fullest availability. Generator controls were upgraded on four of the diesel units to enable remote monitoring and operation of the generating units for better response to system disturbances and system demands because of the increase in variable renewable resources on the system.

DTCC1, DTCC2, and M4–M13 units have operating ranges that can ramp up and down to accommodate fluctuations in the availability of variable renewable energy and/or system load.

Hana. Hana has two internal combustion diesel units that provide firm generation and primarily provide support to the Hana area during transmission maintenance and system disturbance. These units will continue to be operated to support the Hana area.

Lana'i-Miki Basin. Lana'i has a centralized generating station with nine internal combustion diesel units that provide firm generation, frequency response and regulating reserves, system inertia, reactive power and voltage regulation, and the primary source of fault current for the system. These units can start and provide generation in a relatively short time period. Generator control upgrades were completed in 2015 to enable remote monitoring and operation of the generating units. Maui Electric also has an agreement to operate a combined heat and power (CHP) unit that is expected to return to service in 2017. The Lana'i system does not have AGC and, therefore, the demand for electricity is shared equally between the online units in an isochronous mode of operation.

Maui Electric runs a minimum number of baseload units on Lana'i, typically two. The CHP unit can replace one of the two diesel units that provide baseload power for the system at Miki basin. When additional units are needed, they are committed in the most economical order given operational constraints.

Maui Electric applied for and is awaiting approval from DOH for modifications to our air permit that allow lower minimum operating levels on the baseload units to accommodate the addition of more renewables to the system.

Molokaʻi–Palaʻau. Molokaʻi has a centralized generating station with nine internal combustion diesel units and one diesel combustion turbine that can start and provide firm generation, frequency response and regulating reserves, system inertia, reactive power and voltage regulation, and is the primary source of fault current for the system. These internal combustion diesel units can start and provide generation in a relatively short time period.

Maui Electric currently operates with two baseload units on Molokaʻi because this is the lowest number of base loaded units that satisfy our single contingency criteria. When additional units are needed, they are committed in the most economical order given operational constraints. The Molokaʻi system does not have AGC; therefore, the demand for electricity is shared equally between the online units in an isochronous mode of operation.

Maui Electric applied for and received approval from the DOH for modifications to our air permit that allow lower minimum operating levels on the baseload units to accommodate the addition of more renewables to the system. In addition, generator control upgrades have been completed that enable remote monitoring and operation of the generating units.

Hawaiʻi Electric Light Plan for Increasing Generation Flexibility

Hawaiʻi Electric Light has analyzed the operation of existing resources and planned resources. The operational plans incorporate the results of consulting work to evaluate optimization of existing resources, and build upon previous cycling and turndown studies (including the outcome of the RSWG studies), Electric Power Research Institute (EPRI) publications, and other industry literature. We have taken a holistic approach to operational flexibility and have incorporated into our operational and planning processes procedures and policies enabling generation flexibility. The present utilization of dispatchable generation reflects substantial changes from past use in order to accommodate increased renewable energy, including variable wind and solar. There is increased offline cycling, increased ramping, and reduced minimum dispatch limit while retaining ramping capability. The more recent generation additions, such as the combined cycle facilities at HEP and Keahole, incorporated flexibility features into their design.

The historical operation of the Hawai'i Electric Light system included a fleet of fast-start generators; these have been leveraged as flexible resources that have proven invaluable in reliable integration of a large amount of wind and distributed solar PV energy.[9]

In the analysis performed after the 2014 PSIP and identified as necessary measures in that filing, security and reliability studies identified the need for increasing contingency reserve requirements of reliable operation of the power system with existing and increasing levels of DG-PV. As part of our action plan, energy storage will be added to the mix of resources to provide.

Hawai'i Electric Light has implemented many changes in the operation and capabilities of existing generation assets, to support increased levels of renewable energy and maintain acceptable cost and reliability.

- Lowering of the dispatch minimums on Hill 5, Hill 6, and Puna Steam to reduce excess energy issues and enable greater acceptance of variable renewable energy.
- Increasing ramp rate and primary frequency response for Hill 5, Hill 6, and Puna Steam to improve contribution to frequency response and regulation.
- Adjusting regulating reserve requirements based on real-time observation of variability: maintain low levels of reserve for quiescent conditions and higher levels of reserve for variable wind and solar conditions.
- Incorporating variable solar and wind forecast into unit commitment decisions.
- Implementing of centrally controlled curtailment for larger distributed solar and FIT projects.
- Adding of remote control curtailment for the Wailuku River Hydro project. Offline cycling of Puna Steam and Hamakua Energy Partners, after confirming (through analysis) that acceptable reliability could be maintained.
- Incorporating dispatch control into the Puna Geothermal Venture expansion, and increasing the potential geothermal capacity by 8 MW.

The results of past security analysis produced minimum criteria for system reliability for generation units. With that information, units not necessary for system security and reliability are subject to economic unit commitment dispatch, with consideration of the incurred daily cycling costs. The present system operation at Hawai'i Electric Light incorporates routine daily cycling of the Hamakua Energy Partners (HEP) combined cycle plant. Puna Steam was, for a period of time, cycled on a seasonal basis: left offline with preservation measures for extended periods and brought back online when needed to ensure adequate capacity. Based on the present low cost of its fuel, Puna Steam can

[9] For more details, see Exhibit 11: Generation Flexibility Plan, Docket No. 2012-0212, Hawai'i Electric Light, Inc. Power Supply Plan, filed April 21, 2014.

economically serve demand provides routine peaking energy in addition to operating to maintain adequate margins.

There have been occasional adequacy of supply issues created through increasing offline cycling. The present operation represents a significant reduction in the number of fossil generation units historically operated and relies more upon cycling. The reliability impacts from the increased cycling of generating units occur due to the increased potential for shortfall from the delay in startup or startup failure, and the reduction of capacity available quickly during periods that Puna Steam is in layup.

In addition to managing online variability (which requires ramping and reserve capacity online), it is increasingly difficult for the System Operator to determine when to start and stop generation due to the increased uncertainty in demand to be served. This is called "unit commitment". Unit commitment decisions seek to bring the mix of generation online that can reliable meet demand at the lowest cost. The commitment of generation has been complicated by the large amount of variable energy from wind and solar, the latter of which continues to increase. To facilitate operation, state-of-the art forecasting tools are now integrated into the control room. These tools continue to be refined based on site visits from the developer and feedback from the system operators. Nonetheless, there remains a great deal of uncertainty in the forecast, which can lead to under- or over-committing the generation. Under-committing occurs when production is lower or a down-ramp occurs, and may lead to a generation shortfall and the need for supplemental or emergency generation. Over-committing occurs when production is higher than expected, and can lead to inefficient dispatch (higher cost), and may contribute to excess energy conditions requiring mitigation by reducing renewable energy or taking generation offline.

Expanded Turndown Range

Hawai'i Electric Light improved the turndown of its steam units to lower loads. Minimum dispatch limits were reduced through various plant modifications including combustion controls and equipment. The following reductions were made from the levels in 2012. The Hill 5 minimum regulation limit was reduced from 9 MW to 5 MW. The Hill 6 minimum regulation limit was reduced from 16 MW to 8 MW. The Puna Steam regulation limit was reduced from 8 MW to 6 MW. The minimum regulation dispatch limits for other significant units are 27/22 MW for Puna Geothermal and 9 MW for Keahole and HEP in single-train. Dispatch limits (continuous operation limits) are typically one MW higher than the regulation limit for most of the resources. In the case of the Puna Geothermal Venture facility, dispatch of the facility is presently unable to meet the requirements for regulation under automatic generation control. They are actively working on increasing remote control capability, following restoration of capacity which had been lost due to well impacts that occurred during the plant outage following Tropical Storm Iselle.

Fast-Start and Peaking Resources

Existing generation resources provide a significant amount of fast-start, fast-ramping capability. The resources consist of small diesel units and simple cycle gas turbines

For supplemental and emergency purposes, including to cover for forecast errors, Hawaiʻi Electric Light has available 46.3 MW that can be started in 20 minutes or less, and 29.5 MW from small diesel units that can be brought online in 2.5 minutes or less. These units are increasingly used to cover for start-failure of cycled units and short-term generation needs caused by forecast errors. The availability of these units allows the operator to adjust generation quickly in response to changes in net demand. They are also used to restore under-frequency load shed.

The existing available capacity for fast-start resources is sufficient to meet supplemental reserve requirements.

The System Operators are increasing using the simple cycle peaking unit CT3 to manage the change in demand created by variable distributed solar. The impact of distributed solar-PV creates a short-term need for generation to meet the increase in demand (morning load rise). Due to the impact of distributed solar, the highest daytime peak can occur any time between 7 and 9 in the morning before PV production begins. When the solar production is uncertain, or when it is predicted to be significant, the system operators will commit CT3 for the short-term need, rather than HEP or Keahole combined cycle train to avoid starting a combined cycle unit for only a short period. Although combined cycle units are more efficient, they take longer to come online. In the case of HEP, under the PPA terms the System Operator may only start each train once per day, so once the unit is started it has to be kept online unless it is not expected to run for the evening peak

Frequency Response, Regulation, and Ramp Rates

Generators and technologies differ in their ability to contribute to essential grid services. To best meet system needs for frequency response, regulation, and ramping, new resources are required to provide these capabilities to maintain system security and reliability. Moreover, where possible, ramping and regulation capabilities must be provided or improved from existing resources. As part of continuous improvement initiatives, ramp rates were increased for all the utility-owned steam units since mid-2012. Increased dispatch range also improves regulation capabilities by allowing a larger contribution of a generator to both up and down reserve.

As part of its expansion to 38 MW, Puna Geothermal Ventures (PGV) changed its facility characteristics from a passive energy source to one that provides frequency response, voltage response, and dispatch under Automatic Generation Control (AGC). PGV however presently has only limited primary frequency response and capability to operate under AGC. The rate and range of response has been limited both because of controls issues since Tropical Storm Iselle. Hawaiʻi Electric Light plans to continue working with PGV in increasing its operational flexibility, following its restoration to 34.5 MW capacity (following its deration after Hurricane Iselle) and achieving 38 MW, which is anticipated to be within the next few months.

Analysis including new firm capacity renewable resources assumed that they would provide grid services comparable to similarly sized conventional plants. To achieve 100% renewable generation with acceptable reliability, a renewable resource must provide the system reliability requirements presently met by the generating units at Keahole Power Plant (through a similar operational and technical capabilities and a location near to Keahole) and support east-west power flows and voltages without requiring significant transmission infrastructure.

Future new utility-scale variable generation (such as planned wind plants) will also be designed to incorporate technical and operational capabilities available in present day wind plants, including inertial response, ramp rate control, frequency response, active power control, and disturbance ride-through to contribute to grid operational requirements, mitigate impacts of the variability, and lesson the need for other resources to provide such services.

Because of the impacts of DG-PV, increased contingency response (that is, fast frequency-responding reserves) and fast-ramping regulating reserves are required, plus ride-through capabilities from DG-PV. To meet these needs, an energy storage system with response capabilities in excess of generation capabilities will be added to the system to provide contingency reserves. To meet the faster ramping capabilities, the fast ramp capabilities of the existing combustion turbines will be leveraged.

MUST-RUN GENERATION REDUCTION PLAN

Integrating renewables into our system needs to be accomplished safely and reliably. As discussed earlier, improving the flexibility of the generating fleet is an important piece to integrating larger amounts of variable resources. Maintaining system security is also very important because without it, the ability of the system to withstand sudden disturbances is compromised. System security is maintained by operating the system with sufficient inertia or fast frequency response, or primary frequency response, limiting the magnitude of the contingency event, maintaining adequate contingency reserves and maintaining system fault current; at times requiring the system operator to sacrifice efficiency for reliability.

The approach taken in this PSIP update was to define and determine the amount of technology-neutral ancillary services for meeting reliability criteria instead of relying on must run generating units. This allows other resources to be used to provide the necessary ancillary services to make the system secure if them meet the requirement defined by the analyses. Demand Response programs, Distributed Energy Resources, and fast frequency response storage technologies could be used to provide the ancillary services and would displace the need to run firm generating units which would provide headroom for more renewables on the system. Variable renewable energy resources added in the future will provide upward and downward reserves. Synchronous condensers will also be used to provide reactive power and the required system fault current to operate protective relays in lieu of generating units. Together, this will reduce the system requirement for requiring generating units to be run to make the system safe and reliable.

It's important to note that maintaining a minimum capacity of fault current ensures protective relay schemes will operate. This does not ensure that the system has sufficient fault current to maintain transient voltage stability. The companies must perform analyses to determine an acceptable short circuit ratio (SCR) at critical busses to maintain transient voltage stability. The utility industry has yet to develop a standard for SCR.

Removal of a must run generating unit constraint assumes the resources that provide the fundamental grid services (inertia, frequency response reserves, reactive power, fault current) are online in sufficient quantities to ensure system stability and public and equipment safety. If these resources are not available, system security must be provided by synchronous generators.

The Companies filed a "Value of Services Methodology" in Docket No. 2015-0412 on December 14, 2016 at the Commission's request. This document described the assumptions and modeling methodologies to be used to value each of the grid services pursued by the demand response portfolio in as technology-neutral a manner as possible. The Companies plan to file a Revised DR Portfolio filing in February 2017.

Hawaiian Electric

The analysis conducted for the Hawaiian Electric system assumed that there would be no must run generating units from 2019 except for HPOWER and AES to comply with current PPA contract terms. The system security analysis was performed on the PLEXOS cases as described in Appendix O: System Security Analysis.

Hawai'i Electric Light

The analysis conducted for the Hawai'i Electric Light system assumed that there would be no must run generating units from 2020 except for PGV to comply with current PPA contract terms. The system security analysis was performed on the PLEXOS cases as described in Appendix O: System Security Analysis.

Results of the QV analysis indicates that cycling Keahole offline could trigger an overload condition on L6200 for an N-1 contingency. Sensitivity analysis to install synchronous condensers at Keahole did not mitigate the overload condition. Sensitivity analysis was also performed with L6200 operating at a higher ampacity that resulted in no overload condition and no requirements for synchronous condensers at Keahole. The L6200 Transmission Line Rebuild project is in Hawai'i Electric Light's action plan.

Maui Electric

The analysis conducted for the Maui system assumed that there would be no must run generating units from 2022 when Kahului Power Plant is decommissioned and new generation is added.

The analysis conducted for the Moloka'i and Lana'i systems assumed that there would be no must run generating units from 2020 except for Kahului 3 or 4. Maui's 23 kV system requires 16 MVA of fault current to ensure protective relay schemes will operate.

The analysis conducted for the Moloka'i and Lana'i systems assumed that there would be no must run generating units from 2020.

The system security analyses were performed on the PLEXOS cases as described in Appendix O: System Security Analysis.

ENVIRONMENTAL COMPLIANCE PLAN

Mercury and Air Toxics Standards (MATS) Compliance Strategy

The MATS rule is applicable only to the steam electric units on Hawaiian Electric's O'ahu system.

The MATS rule required Hawaiian Electric to control and measure particulate matter (PM) emissions as well as fuel moisture content as surrogates for reducing hazardous air pollutants (HAPs), including heavy metals and acid gases, from its oil-fired steam generating units by April 2016. The MATS rule originally required Hawaiian Electric to reduce emissions of HAPs, including heavy metals and acid gases, from its oil-fired steam generating units by April 2015. On November 6, 2013, Hawaiian Electric obtained from the State DOH a one-year extension on the April 2015 compliance date. [10]

To be ready for the April 2016 compliance date, Hawaiian Electric conducted emissions testing for each steam unit on O'ahu that is subject to the MATS PM emission standard. Tests involved measuring PM emissions to confirm the effectiveness and repeatability of potential MATS solutions. Testing throughout 2014 and 2015 allowed Hawaiian Electric to collect data to confirm the accuracy of the MATS solution chosen. As announced in the Companies' January 2016 Update of Fuels Master Plan (FMP),[11] Hawaiian Electric's preferred compliance solution was to utilize a 70/30 blend of low sulfur fuel oil (LSFO) and diesel at Kahe 5 and 6, but to continue using 100% LSFO at Kahe 1–4 and Waiau 3–8.

After the FMP was filed, additional testing on Kahe 5 and 6 demonstrated that the units can meet MATS requirements using 100% LSFO. This is a departure from Hawaiian Electric's initial concern that all units would have to burn a more expensive 70/30 or 60/40 MATS fuel.

National Ambient Air Quality Standards (NAAQS)

At this time, NAAQS rules are only expected to impact Hawaiian Electric. It is currently unclear about the necessity of reducing LSFO use and switching to a lower emissions fuel blend to attain the new one-hour for sulfur dioxide level in the vicinity of the Kahe and

[10] Hawaiian Electric was granted a one-year MATS compliance extension, which places the compliance deadline at April 16, 2016. A second one-year extension is available to utilities through an Administrative Order that would be issued by the EPA. Based on the evaluation criteria established by the EPA in a December 16, 2011 Policy Memorandum, the second one-year extension must be based on a system reliability assessment and is considered a much more difficult extension to obtain. The MATS compliance date is set forth in Title 40 of the Code of Federal Regulations (CFR), Part 63, Subpart UUUUU, National Standards for Hazardous Air Pollutants: Coal-and Oil-fired Electric Utility Steam Generating Units.

[11] The FMP is filed semi-annually, currently in Docket No. 2012-0217. It is used to continually update the Commission and other interested parties of the Companies' fuel strategies and procurement timelines.

Waiau generating stations. The best case scenario, absent the use of natural gas, would be using 100% LSFO. The Companies currently believe the worst-case scenario would be blending 40% LSFO with 60% lower sulfur fuel. For planning purposes, the Companies used a conservative approach and assumed the 40/60 blend will be required.

The Clean Air Act (CAA) requires the EPA to set NAAQS for pollutants considered harmful to public health and the environment. The six "criteria" pollutants are carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, PM, and SO_2. The CAA also requires the EPA to review the NAAQS every five years and to revise the NAAQS to reflect the latest scientific information on the impacts of air pollution on public health and the environment.

In 2010, the EPA revised the NAAQS for SO_2 and NO_2, making them more stringent. The compliance requirements for particles less than 2.5 micrometers in diameter (PM2.5 or "fine particles") were also made more stringent. Based on the Companies' preliminary analysis, the new SO_2 standard poses the greatest compliance challenge. Even though NAAQS potential emission reduction requirements for existing units have been pushed back from the original deadline of 2017 to 2025, the Companies have to consider a variety of compliance options for its long-term fuel procurement strategy and planning assumptions. Lowering sulfur emissions to the required levels could be achieved by either switching to a lower sulfur fuel, or by installing air quality control equipment (backend controls).

The Companies believe that the most cost effective way to meet the future NAAQS compliance requirements is to use a fuel that meets the requirements as opposed to installing costly backend controls. LNG has emerged as a viable option that will comply with air emission standards, while also substantially lowering fuel costs compared to petroleum-based options. A lower-cost, cleaner-burning LNG will result in cost-savings to customers.

New Source Review (NSR) and New Source Performance Standards (NSPS)

NSR and NSPS are CAA programs that may have an impact on the future operation of fossil based generation at Hawaiian Electric, Maui Electric and Hawai'i Electric Light. These programs specifically target older, fossil fuel burning units because they generate more air pollution. EPA and DOH require modern pollution control and monitoring equipment to be added to an existing stationary unit if it undergoes certain changes in operation or there is a major modification to the unit.

The NSR program requires existing facilities to improve emission control performance as technology improves over time as older equipment needs to be modified and results in a significant emissions increase. NSR requires the entity to go through a permitting process with EPA and DOH to, among other things, identify the best available control technology that will be used to reduce and monitor emissions. The NSPS program establishes limits for how much of a regulated pollutant can be emitted from new or recently modified units in certain source categories, such as boilers, combustion turbines, and stationary compression ignition and reciprocating internal combustion engines. The NSPS emission limits apply to existing units where there is a physical change or change in the method of operation that increases the amount of an air pollutant currently emitted or that adds emissions from a new air pollutant.

Some of the major projects required to continue to run older units at Hawaiian Electric, Maui Electric, and Hawaiʻi Electric Light could require add-on pollution control to ensure the units emit fewer emissions as they age. The costs associated with emissions control programs will be considered, as units require major modifications to continue to operate in the future.

Greenhouse Gas (GHG) Regulations

State of Hawaiʻi Act 234 requires a statewide reduction of GHG emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990. The state GHG rules became effective on June 30, 2014, and require all entities that have the potential to emit GHGs in excess of established thresholds to reduce GHG emissions by 16 percent below 2010 baseline emission levels by January 1, 2020. Affected facilities were required to submit an Emissions Reduction Plan (EmRP) to the DOH for approval by June 30, 2015.

Hawaiian Electric, Maui Electric, and Hawaiʻi Electric Light have a total of eleven facilities affected by the state GHG rule. Together, these facilities account for almost 56 percent of the 2010 baseline emissions from all affected facilities. Hawaiian Electric made use of the partnering provisions in the DOH GHG rule to prepare a single EmRP that covers all eleven of the Company's affected facilities, and has committed to a 16 percent reduction in GHG emissions company-wide. Hawaiian Electric submitted the Company's EmRP to the DOH on June 30, 2015. The DOH will incorporate the proposed facility-specific GHG emission limits into each facility's source permit based on the 2020 levels specified in Hawaiian Electric's approved EmRP following DOH approval.

As part of a negotiated amendment to the Power Purchase Agreement (PPA) between AES Hawaiʻi and Hawaiian Electric, Hawaiian Electric has agreed to include the AES Hawaiʻi coal-fired power plant on Oʻahu as a partner in the Company's EmRP. Similarly, with the planned acquisition of the HEP facility by Hawaiʻi Electric Light, the GHG emissions from the HEP facility will also be addressed in the Company's EmRP. Both the AES PPA amendment and the HEP acquisition are subject to Commission approval, so including these facilities in the Company's EmRP will be done at a following

Commission approval. Hawaiian Electric is working with the DOH on the timing of the EmRP modifications to address these changes in the partnership.

As part of President Obama's Climate Action Plan, the EPA was directed to adopt GHG emission limits for new and existing EGUs. The EPA issued the final federal rule for GHG emission reductions from existing electric generating units—also known as the Clean Power Plan—on August 3, 2015. The Clean Power Plan set interim state-wide emissions limits for existing EGUs operating in the 48 contiguous states that must be met on average from 2022 through 2029; final limits will apply from 2030. On February 9, 2016, however, the U.S. Supreme Court granted a stay of the Clean Power Plan pending resolution of several challenges to the rule until several petitions for review in the U.S. Court of Appeals for the D.C. Circuit Court can be heard and a decision is rendered.

The final Clean Power Plan did not set forth guidelines for Alaska, Hawai‘i, Puerto Rico, or Guam because the Best System of Emission Reduction established for the contiguous states is not appropriate for these locations. The EPA indicated its intent to work with the governments for Alaska, Hawai‘i, Puerto Rico, and Guam to gather additional information on emissions reduction measures available in these jurisdictions, particularly with respect to renewable generation. Given the recent Supreme Court decision and pending further action by EPA and federal courts, the timing for establishing Federal GHG emission reduction requirements that may affect Hawaiian Electric's power plants is uncertain.

316(b) Fish Protection Regulations

Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with once-through cooling water systems to ensure that the location, design, construction, and capacity of the systems reflect the best technology available to minimize harmful impacts on the environment. Most impacts are to early life stages of fish and shellfish that become pinned against cooling water intake structures (impingement) and are drawn into cooling water systems and affected by heat, chemicals, or physical stress (entrainment).

The EPA issued the final 316(b) fish protection rule on May 19, 2014. This rule titled, *Final Regulation to Establish Requirements for Cooling Water Intake Structures at Existing Facilities*, applies to Hawaiian Electric's Honolulu, Kahe, and Waiau steam electric generating stations. The Kahe and Waiau facilities are required to comply with the impingement and entrainment standards. The Honolulu facility, because of its lower actual intake water flow when operating, may have to comply with only the impingement standard. Honolulu is currently deactivated, but will have to comply with the 316(b) fish protection rule before it can be reactivated.

The final regulation does not specify the best technology available (BTA) standard for entrainment, but states that "the Director must establish BTA standards for entrainment for each intake on a site-specific basis."[12] In Hawai‘i, the "Director" is the Director of the Hawai‘i's DOH.

Significant studies at Kahe and Waiau need to be completed before the DOH can make a final determination of the technology requirements for the affected facilities. Six years of impingement and entrainment data have been collected at Kahe and Waiau and will be used to complete the required studies for these facilities. A preliminary review of the data indicates that closed-cycle cooling (CCC) or cylindrical wedgewire screens will not be required to comply with the 316(b) rule, but fish-friendly traveling screens and fish-return systems may be required.

No firm deadline for compliance is specified in the final rule. Facility-specific compliance schedules will be developed based upon the results of the required studies, in consultation with DOH, and in coordination with the facilities' NPDES permit cycles.

NPDES compliance also impacts Maui Electric's Kahului Power Plant (KPP). As discussed in the Fossil Generation Retirement Plan, Maui Electric plans to retire KPP's generating units no later than November 2024 in accordance with the compliance plan as approved by the DOH in July 2015.

12 §125.94(d), page 538.

KEY GENERATOR UTILIZATION PLAN

This discussion recognizes the unique economic and operational challenges that exist for key O‘ahu and Maui generating units.

AES Hawai‘i (AES)

AES is a 180 MW coal-fired power plant serving O‘ahu. In November 2015, Hawaiian Electric entered into an Amendment No. 3, for which Commission approval has been requested. If approved by the Commission, Amendment No. 3 would increase the firm capacity from 180 MW to a maximum of 189 MW until the end of the existing PPA term.

The existing PPA between AES and Hawaiian Electric expires on September 1, 2022. The PSIP assumes that the AES PPA is not renewed as of its expiration date.

Kalaeloa Energy Partners (KPLP)

KPLP is a combined-cycle combustion turbine generator that currently operates on LSFO. As shown in its Adequacy of Supply report filed April 11, 2014, in the absence of new capacity, Hawaiian Electric needs KPLP’s capacity of 208 MW to meet the generating system reliability guideline. In the absence of KPLP, it is estimated that there would be a reserve capacity shortfall of about 175 MW.

Hawaiian Electric and Kalaeloa are in negotiations to address the PPA term that ended on May 23, 2016. The PPA automatically extends on a month-to-month basis as long as the parties are still negotiating in good faith. The month-to-month term extensions shall end 60 days after either party notifies the other in writing that negotiations have terminated. On August 1, 2016, Hawaiian Electric and Kalaeloa entered into an agreement that neither party will give written notice of termination of the PPA prior to October 31, 2017. The KPLP Facility is over 24 years old and will require maintenance that is sufficient to allow the facility to continue to operate with its high degree of reliability over an extended PPA term. This is being considered in the negotiations.

At an appropriate price and with appropriate operating flexibility, KPLP represents a viable future generator for the O‘ahu power system in the future. The KPLP facility is expected to be a viable generator in the future. Because KPLP is an independent power producer (IPP), it is impossible to identify its value in the future without a finalized contract identifying pricing, operating flexibility, and other parameters.

Campbell Industrial Park Combustion Turbine No. 1 (CIP CT-1)

CIP CT-1 is a combustion turbine that currently operates firing biodiesel. It is the type of generating unit that is compatible and complementary on a power system with increasing amounts of variable renewable generation. CIP CT-1 provides offline reserve, online spinning reserve, and can be turned on and synchronized to the grid within 22 minutes. It can also be readily turned off to accept more variable renewable generation onto the grid. When operating, it contributes a relatively high level of system inertia, can help manage system frequency by responding to minute-to-minute load demand control signals, and can ramp up rapidly to offset rapid down ramps of variable renewable generation.

The fuel efficiency of CIP CT-1 is lower than the AES and KPLP units. For example, at maximum load, its fuel efficiency is about 11,700 Btu/kWh-net. Kahe 6 has a fuel efficiency of about 10,050 Btu/kWh-net at full load. In combination with the higher cost of biodiesel compared to LSFO, CIP CT-1 is the highest cost generator on the O‘ahu power system.

Once the Schofield Generating Station (SGS) is in service first quarter of 2018, CIP CT-1 will switch to using diesel as its normal operating fuel. The biodiesel that would have otherwise been used at CIP CT-1 will subsequently be used in the new SGS engines. Pacific Biodiesel supplies the biodiesel currently used in CIP CT-1 via a contract that has a minimum purchase amount of two million gallons per year. This contract expires in November 2017.

Whether operated on diesel or biodiesel, CIP CT-1 represents a vital resource for the O‘ahu system because of its operating characteristics. The frequency with which CIP CT-1 is operated will depend on its relative fuel cost and system conditions.

Other Generating Units Owned and Operated by Hawaiian Electric

With a mandate for 100% RPS by 2045, we envision declining use of oil-fired thermal generating units. Thermal generation is, however, desirable to accommodate cleaner and less price volatile LNG. They will also provide strategic use of liquid biofuels that allow the thermal units to “back up” the variable renewable energy and energy storage systems in those situations when there is no alternative to meet system demand.

Maui Electric Key Generation Units

These units provide benefits to the Maui system, including system security, or flexibility.

- Dual-train combined cycle units: high efficiency, regulating reserves, contingency reserves.

- Combustion turbines: operational flexibility through startup availability and dispatch.
- Small diesel internal combustion engines (MX1, MX2, M1, M2, M3): quick-starting
- Large diesel internal combustion engines (M10, M11, M12, M13): operational flexibility through startup availability and dispatch. It is also anticipated that the small and mid-size diesel units will be operated very infrequently, as they will be designated to operate during peak load periods or when variable renewable resources are unavailable.

Hawai‘i Electric Light Key Generation Units

The Puna Geothermal Venture facility provides firm capacity renewable energy, and will continue to be a significant resource towards renewable energy goals for the foreseeable future.

The dual train combined cycle units at Keahole and HEP provide benefits that include system security, fuel efficiency, and fuel flexibility. These resources have flexible operational characteristics, can cycle offline, and used economically to serve demand.

The steam units provide excellent system stability and primary frequency response, and with the present modifications, good dispatch range ad ramping capability. The minimum dispatch limit (in MW) is lower than combined-cycle units. The three steam units are presently the lowest cost resources to serve demand because of the low cost of IFO fuel. They are economically serving demand now and for the near term, if the fuel costs remain low compared to alternative available resources. The units, however, are inefficient and not expected to remain cost-competitive with higher fuel costs; they are not candidates for switching to more expensive renewable energy fuels, instead are assumed to be candidates for decreased operation or retirement with the addition of renewable resources.

The fast-start diesels and simple-cycle combustion turbines, which have played a large part in the integration of the present high levels of variable renewable energy and support the amount of offline cycling and low online reserves of today, will continue to play important roles in providing fast replacement reserves and supplemental reserves for forecast errors, ramping events, forced outages (including failed start), and other short-term and emergency energy needs.

OPTIMAL RENEWABLE ENERGY PORTFOLIO PLAN

Hawaiian Electric's Renewable Energy Portfolio Plan

Hawaiian Electric's analysis of optimal renewable portfolio plans begins with Chapter 3: Analytical Approach that describes theoretical least-cost plans for individual islands (O'ahu, Maui, and Hawai'i Island) and interisland interconnected plans optimized by E3's RESOLVE model. The Companies used the PLEXOS model to analyze a subset of cases based on E3's optimized plans as described in Chapter 4: Analytical Results. The financial evaluation of the core cases is in Chapter 5: Financial Impacts.

Maui Electric's Renewable Energy Portfolio Plan

Maui Electric's analysis of optimal renewable portfolio plans begins with Chapter 3: Analytical Approach that describes theoretical least-cost plans for individual islands (O'ahu, Maui, and Hawai'i Island) and interisland interconnected plans optimized by E3's RESOLVE model. The Companies used the PLEXOS model to analyze a subset of cases based on E3's optimized plans as described in Chapter 4: Analytical Results. The Companies used PLEXOS to develop optimized resource plans for Moloka'i and Lana'i which is also described in Chapter 4: Analytical Results. The financial evaluation of the core cases is in Chapter 5: Financial Impacts.

Hawai'i Electric Light's Renewable Energy Portfolio Plan

Hawai'i Electric Light's analysis of optimal renewable portfolio plans begins with Chapter 3: Analytical Approach that describes theoretical least-cost plans for individual islands (O'ahu, Maui, and Hawai'i Island) and interisland interconnected plans optimized by E3's RESOLVE model. The Companies used the PLEXOS model to analyze a subset of cases based on E3's optimized plans as described in Chapter 4: Analytical Results. The financial evaluation of the core cases is in Chapter 5: Financial Impacts.

GENERATION COMMITMENT AND ECONOMIC DISPATCH REVIEW

The Generation Commitment and Economic Dispatch Reviews are similar for all three operating utilities.

Prudent Dispatch and Operational Practices

Our unit commitment and economic dispatch policies are based on safe and reliable operation of the system, minimizing operating costs, and complying with contractual and regulatory obligations. The daily generation dispatch process is illustrated in Figure M-1.

With increasing amounts of distributed solar, large amounts of wind power, and increased offline cycling, state-of-the art forecasting tools have been integrated into the control room. These tools are used to inform unit commitment decisions with forecast power production, variability, and indication of uncertainty in the forecast. There remains a great deal of uncertainty in the forecast, however, which can lead to under- or over-committing the generation. Under-committing occurs when variable production is lower than forecast or is more variable than expected; and may lead to a generation shortfall or underfrequency load-shedding; and need for supplemental or emergency generation. Over-committing occurs when variable production is higher than forecast or more variable than expected and may lead to excess energy and over-frequency, which depending on severity can cause system disturbances, the need to cut back output from renewable resources, and possible operation below minimum dispatch limits.

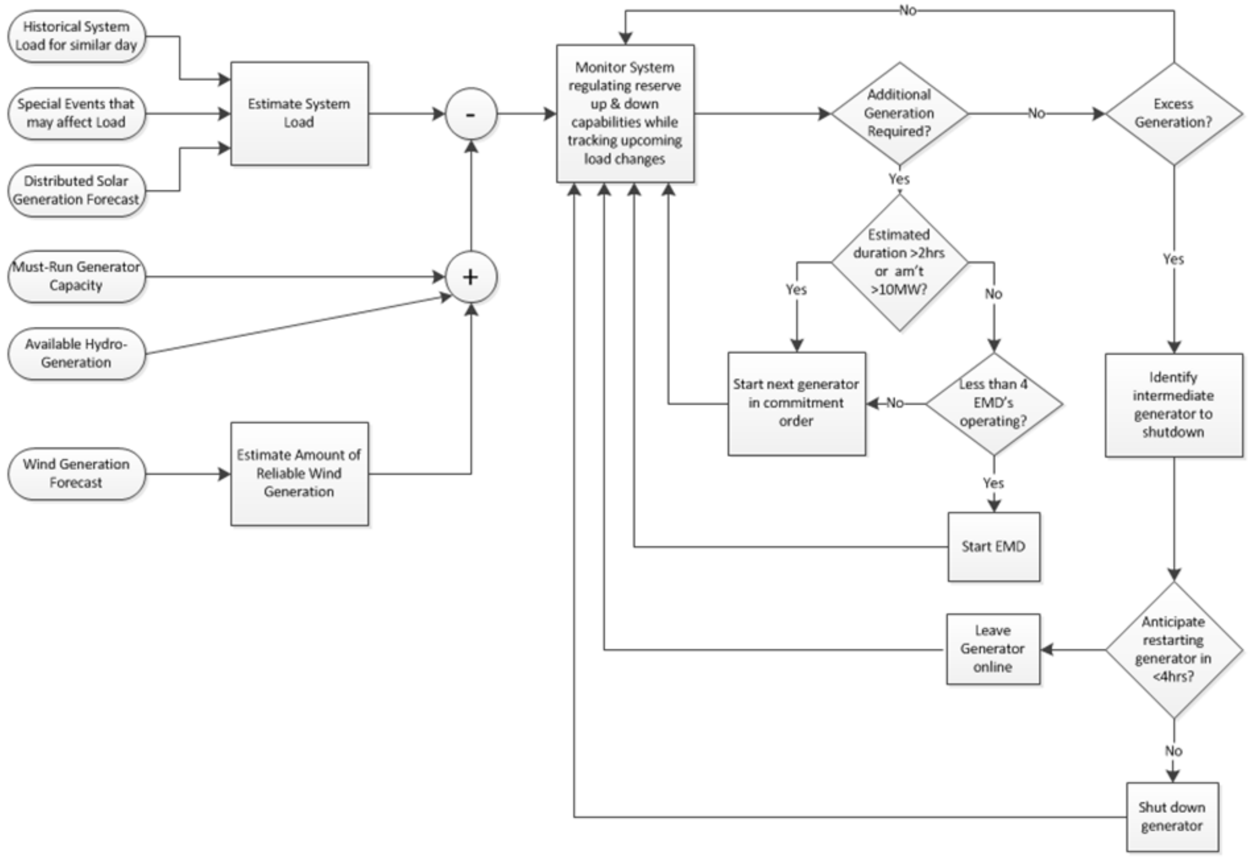

Figure M-1. Daily Generation Dispatch Process

Maui Electric and Hawai'i Electric Light have integrated its state-of-the art wind and PV forecasting into the control room, which is used for the daily unit commitment decisions. The amount of online reserves carried is adapted in real-time based on the observed variability of the net demand, primarily driven by wind and solar. Unit commitments are based on economic dispatch, subject to the system security constraints, contract requirements for minimum purchase (such as PGV's schedule), unit limits, and must-take energy. A factor in unit commitment is the duration of the load to be served. With the increase in DG-PV, a shorter day peak occurs during which it may be more economical to start up a faster-starting but less-efficient resource (such as a simple-cycle turbine).

The Companies must also evaluate whether to return deactivated units to service, such as Hawai'i Electric Light's Puna Steam unit.

Additional projects are being developed that will further integrate the forecasting, services, and visualization into the EMS and provide additional control of distributed energy resources. In the future, the unit commitment decisions will incorporate net-demand forecasts, which include the forecast wind and solar production and demand response options. For supplemental frequency control and reserves, new resources will be integrated into the EMS, including storage, demand response, and response capabilities from variable resources.

Minimizing Ancillary Services Costs

The process to identify system security constraints, and the combinations of resources that can be used to meet them, is:

- Determine system constraints.
- Identify the resource mix that meets each of them.
- Select the lowest-cost combination of resources to operate.

For all three operating utilities, additional security constraints are imposed with increased concentrations of variable renewable resources. Therefore, the projected increase in DG-PV may have an impact on ancillary service costs. We will continually evaluate the economics of using existing resources to meet ancillary services and system security requirements versus meeting those needs with alternative resources (including energy storage and demand response).

Maximizing the Use of Available Renewable Energy

The commitment and dispatch of renewable energy resources depends upon the contract terms for those resources and whether or not the system operator has visibility and control over the generation. If the resource can be economically dispatched, it is put under automatic generation control (AGC), and its output is determined by its marginal cost relative to the marginal cost of other resources. Examples of this type of renewable resource may include geothermal, generating units using renewable biofuels, waste-to-energy projects, and other “firm” renewable projects. In the PSIP action plans, dispatchable renewable energy, on systems where it is available, has been identified as providing value by displacing maximum amount of fossil fuels through the high capacity factor. However, these types of resources are not readily available on O‘ahu unless procured through interconnection to other islands.

Variable renewable energy projects have been contractually treated as must-take, variable energy. These are accepted regardless of cost, but their output is reduced as needed when all intermediate units are offline and there remains excess energy production. In this case, the system operator curtails the output of variable energy providers to the degree necessary to keep the system in balance and provide response reserves. Most curtailments are partial—the output is limited, but the resource is not restricted to zero output. When excess energy necessitates curtailment, it is performed in a manner consistent with the PPAs associated with the affected resources and in accordance with a priority order established by the system operator.

In addition to excess energy situations, curtailments can also be required for system constraints such as line loading, phase angle separation, line maintenance, and frequency impact from power fluctuations. Curtailments for system constraints are applied to the resources as needed to address these constraints; they are not subject to the priority order used for excess energy curtailments. Curtailments are also performed at the request of wind plants for wind conditions, and equipment issues.

The vast majority of DG-PV is not visible or controllable by the system operator. These resources serve demand ahead of all other resources. Additional growth in DG-PV is forecast to cause increased curtailments of utility-scale variable renewable resources, unless DG-PV is required to provide the visibility and control to the system operator.

As the islands evolve to ever increasing levels of renewable energy, the ability to treat any type of energy as "must take" is increasingly limited in the absence of storage. The islands serve only the demand on the island systems and cannot export excess production as is done in other interconnected areas. Accommodating the renewable resources will displace existing generation that provided dispatchable energy, adjusted to meet demand, and many other characteristics to keep the power system stable and operable. These capabilities to adjust output to serve demand, respond to frequency, regulate voltage, and other stability factors will be increasingly relied upon from variable and firm renewable resources as the systems are transformed to economically and reliably serve the energy needs of the future with 100% renewable energy. This increasing contribution to grid management will require changes to both procurement terms and technical and operational capabilities of all renewable resources, including distributed energy resources (DER).

Energy Management Systems (EMS)

The operation of the system is facilitated by use of a centralized Energy Management System (EMS). The EMS provides the system operator with constantly updated, real-time information about the operational state of the system. There are three key applications within the EMS:

- Supervisory Control and Data Acquisition (SCADA)
- Real-Time Automatic Generation Control (AGC)
- Real-Time State Estimator

Currently, Moloka‘i and Lana‘i do not have AGC capability because of their small size, and instead rely upon isochronous control units for frequency regulation.

All three operating utilities routinely update the EMS hardware and software platforms for each system to ensure reliable operation, incorporate new industry developments (such as protocols and system security measures), and maintain support from EMS vendors.[13] With the transformation of the utility systems, additional interfaces are required to the EMS for control of distributed generation and new types of resources (such as storage, demand response integration, and variable generators which have varying levels of reserve depending upon set point and available resource). This will require modifications to the interface, new controls, and modeling of the resources within AGC.

To accommodate the migration to a smart grid network and integration of new resources as well as the use of the communications protocols to support this, the Companies are hardening the security of their EMS systems. Hawai'i Electric Light has tested MPLS communication to a remote terminal unit from a secured EMS network.

Additional applications are being developed to facilitate the dispatch decisions and system management with the changing resource mix. As one example, a study indicated the need to have dynamic allocation of circuits to meet the requirements of the underfrequency scheme, due to the impact of distributed solar on the net demand on each circuit. In 2016 an adaptive underfrequency load-shed application for the Hawaii Electric Light System was designed and the implementation is near completion. This scheme assigns circuits to underfrequency load-shed tiers in real-time, reflecting the telemetered demand on each circuit and total load-shed quantity needed at the time. The scheme required deployment of newer relaying equipment at the various distribution substations, to support the adaptive scheme. Testing will begin in the first quarter of 2017.

System Dispatch and Unit Commitment

Unit commitment and dispatch decisions are based upon several factors:

Safety. Our dispatch of generating resources is always subject to ensuring the safety of personnel and the general public.

Reliability. Dispatch and unit commitment must adhere to system security and generation adequacy requirements.

Contractual Requirements. Dispatch and unit commitment must adhere to contractual constraints.

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[13] We operate EMS systems from two different vendors, *Alstom* at Hawai'i Electric Light and Maui Electric, and *Siemens* at Hawaiian Electric.

Cost. After meeting all the forgoing requirements, we commit and dispatch units based on their marginal cost, with lower-cost units being committed and operated before higher-cost units.

When determining the unit commitment and dispatch of generating units, we do not differentiate between dispatchable IPPs and utility-owned assets, nor does the daily unit commitment modeling tool input date differentiate units by ownership. Certain generators do receive a form of priority of energy being accepted onto the system based on the location of the generator, its characteristics, or the contractual obligations unique to the resource.

The acceptance of energy for dispatch is in the following order of preference:

Distributed Generation: Distributed generation resources receive preferential treatment as "must take" regardless of their economic merit for system dispatch. At the present time, we have no control over, or ability to curtail, the majority of distributed generation.

Scheduled Contractually Obligated Generation: These resources are preferentially treated by contract. They are used to serve customer load regardless of their economic merit for system dispatch. Scheduled energy from these resources is taken after distributed generation, but ahead of all other resources, including variable energy providers.

Contractually Must-Run, Dispatchable Generation: The resources cannot be cycled offline and therefore the minimum dispatch level of these resources are preferentially treated; the energy is accepted from these resources regardless of cost, except during periods of maintenance.

Generation to Meet System Security Constraints: These resources provide energy at least at their minimum dispatch limit ahead of other resources, similar to contractual must-run and scheduled generation, plus an amount of reserve capability to provide down regulation. However, once dispatched, the continued operating status of these resources is subject to continual evaluation of their costs relative to other alternative resources that may become available at a lower cost, except where it is required by contract.

Variable Energy: Variable energy is accepted on the system, regardless of cost, after distributed generation, scheduled energy purchases, and continuously operated generation. This energy is accepted regardless of cost and thus presents a constraint on optimized (lowest) cost. If the energy cannot be accommodated because of low demand, curtailment of the resource is ordered according to an established and approved priority order. As stated earlier, variable energy will increasingly be treated as dispatchable and contribute to grid management. This will require additional EMS interfaces.

Dispatchable Resources: Energy from dispatchable resources is taken on the basis of relative cost (economic dispatch). Resources with the lowest variable energy (fuel and O&M) cost will be committed ahead of resources with higher variable costs. Online resources with lower incremental costs will be dispatched at higher outputs ahead of resources with higher incremental costs. The units operated routinely to meet demand, but cycled offline during minimum demand periods, are described as intermediate units. Short-term (daily) unit commitment decisions do not consider fixed costs associated with these resources because the fixed costs will be incurred regardless of whether or not the unit is operated.

Compliance: Permit restrictions or requirements may affect the operation of generation units.

Generator Availability: Generators may be out of service for planned maintenance or unplanned reasons.

Transmission Constraints: Transmission and distribution maintenance plans.

Variable Forecasts: Operational decisions may be different based on wind and solar forecasts versus perfect knowledge of the resource.

Weather: Conditions or other risk conditions may require adjustment of the generation mix to provide additional security margin.

Distributed Energy Resources: At present, visibility and control of distributed energy resources is limited to only larger facilities and FIT projects. As with utility-scale variable generation, DER will be increasingly integrated into the EMS, including monitoring and control capabilities.

Adaptive Underfrequency Load-Shedding: This new application is being developed to enable effective load shed protection schemes under high DG-PV penetration. With increasing amounts of self-generation, the available demand for underfrequency load-shed on each circuit is highly variable and dependent upon solar PV production. The amount of load that must be shed is dependent upon net system demand and contingencies. As mentioned above, a new application on the EMS is being implemented at Hawai‘i Electric Light to assign circuits to the load-shed scheme stages dynamically, based on telemetered available circuit demand and the total system net demand. This effort required modifications to the EMS and deployment of new relay technology at various distribution substations. The project is nearing completion and will begin testing in early 2017.

Utilization of Energy Storage and Demand Response

Energy storage and demand response (DR) programs can provide the system operator with a flexible resource capable of providing capacity and ancillary services. To provide the system operator with appropriate control and visibility, energy storage assets are equipped with essentially the same telemetry and controls necessary to operate generating units. DR used for providing regulating reserves and contingency reserves is also equipped with appropriate telemetry and controls. The specific interface requirements depend upon whether the storage device or DR resource is responding automatically, or is under the control of the system operator. The DR Management System (DRMS) and the Energy Storage Management System (ESMS) is interfaced with an EMS.

For storage or DR that is integrated into the EMS, telemetry requirements include:

- Real-time telemetry for storage that indicates the charging state, the amount of energy being produced, and the device status.
- Control interface to the EMS to enable the increase and decrease of energy output from the storage asset, and for energy input to the storage device for charging.
- Real-time telemetry for DR indicating the breaker status, switch status, and load.
- Control interface to the EMS to configure settings for response to local criteria (for example, underfrequency) or to provide direct remote trip or dispatch control by the system operator.

Storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve. Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource to provide “smoothing” of the renewable resource output.

Short-duration storage is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset’s charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources before the stored energy is depleted. This replacement could be in the form of longer-term storage or generation resources. For the value of DR to be realized in providing a particular grid service, once called, the load cannot return to the system until after a specified time, which is dependent on the type of grid service being provided by the DR resource. Accordingly, the system operator similarly requires information regarding the status of DR, particularly as it relates to the state of the response after an event has been triggered.

Visibility and Transparency in System Dispatch

A high level review of the websites of various independent system operators (ISOs) including PJM (central east U.S.), Midwest ISO (MISO), California ISO (Cal ISO), and the Electric Reliability Council of Texas (ERCOT), shows the following operational information commonly being displayed (along with ISO energy market-specific information such as locational marginal pricing):

- Real time daily demand curve showing actual and forecasted demand, updated at least hourly.
- Hourly wind power MW or MWh being produced and forecasted.
- Other historical renewable energy production in MW (Cal ISO).
- Available generation resources.

Our Renewable Watch site[14] (branded as REWatch), available for our service territories, currently displays the following information, with data refreshed every 15 minutes:

Net Energy System Load. The system load served by generators on the "utility-side" of the meter including those owned by the utility and by IPPs.

Gross System Load. The net system load plus estimated load served by DG-PV on the customer side of the meter.

Solar Irradiance Data. This data is measured in different regions of the island, which are used as input to calculating the estimated load served by DG-PV.

Wind Power Production. Total megawatts of wind power being produced by the various IPP-owned wind facilities selling electricity to the Companies.

We continue to enhance the information available on Renewable Watch and other public displays on our Company website. The information on the REWatch will be supplemented with additional information showing for the previous hour the percentage of the energy supplied by the different resources (IPPs, renewables, and utility-owned generating units). A historical archive of the percentage of the energy produced by each of the resource groups for the previous 24-hour period will be maintained so that the customer can view the changes over time.

These enhancements will address the Commission's objectives of showing the significant use of non-utility generation and renewable resources, most of which (with the exception of our combustion turbine generation CIP CT-1) uses biofuels and are IPP-owned.

In addition, we also make public a description of our economic dispatch policies and procedures via a posting on our website. Combined, the enhancements to our website

[14] https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/renewable-watch.

and the sharing of our dispatch policies and procedures increase visibility and transparency of how generating resources are being dispatched on the power grid.

Our generating unit commitment and dispatch of the generating units is based on the objective of incurring the least cost to the customers while continuing to maintain system reliability. With the introduction of increasing amounts of renewable resources, it has become more important to minimize the use of fossil fuels and contend with the dynamic system changes that occur from the new resources so that reliability can be maintained.

A screenshot from the Renewable Watch–O‘ahu website is shown below in Figure M-2 to provide an example of the variability of the renewable energy resources.

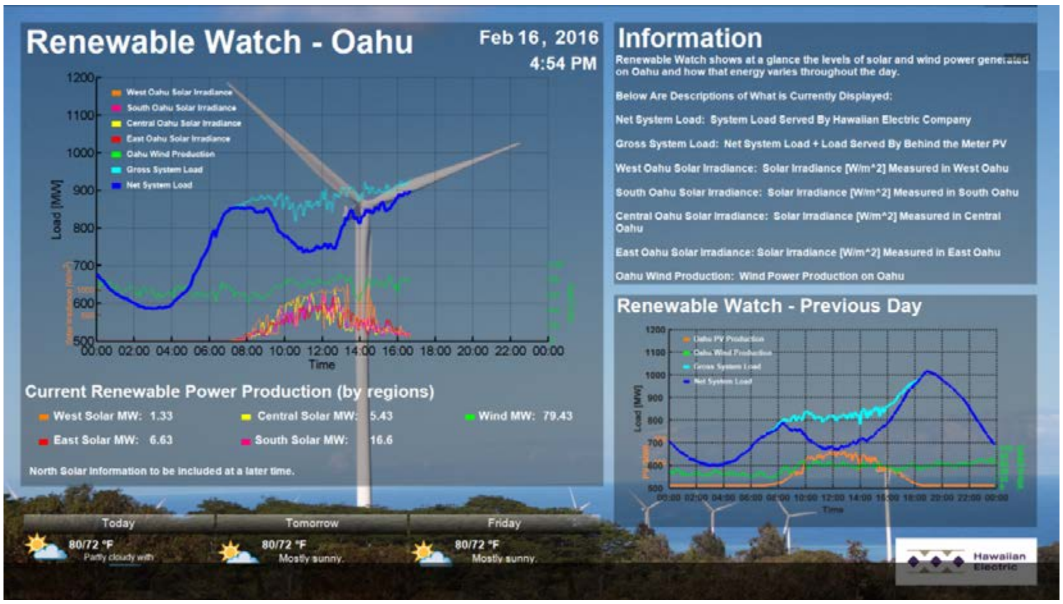

Figure M-2. Renewable Watch–O‘ahu Website Screenshot

The new visualization tools have been under development for each respective systems over the past few years, and are presently integrated to enlighten site visitors. We understand the importance of visibility and transparency of the economic commitment and economic dispatch of resources to show customers that a real effort is being made cost-effectively use fossil fuels and to effectively use available renewable energy. REWatch is currently the only utility site that offers visibility to customer-sited distributed generation (DG-PV) information.

As the mainland regional transmission organizations (RTOs) or ISOs operate real-time and day-ahead markets, these organizations show the price of energy for their market, which may be misleading for Hawai‘i, given that we do not have a real-time market or corresponding balancing need. For RTOs and ISOs, customers are unaware of the system conditions that are dictating how the generating units are being run.

The information displayed on our existing Renewable Watch website is a good starting point for creating visibility and transparency, especially for distributed generation resources.

We continue to work with industry partners (including Stem and Blue Planet) to share real-time system load and generation by percent of power for different resource types like wind, solar and DG resources. We support efforts to share information with customers so they can see their energy use and changes in generating resources from fossil to more renewables on the grid.

N. Integrating DG-PV on Our Circuits

This appendix, through modeling analysis, identifies the anticipated problems on the distribution, sub-transmission, and transmission systems to integrate distributed and grid-scale PV. Various solutions are proposed and considered to address integration impacts, with a discussion about how these investments will remedy interconnection problems. This appendix also discusses the methodology and assumptions used to identify the problems and solutions.

Overview

The PSIP plans presented in this December 2016 update utilize the high DG-PV forecast to meet our customer's energy needs. The high DG-PV forecast assumes that all single-family home customers and certain commercial sectors will meet their total energy needs through the installation of a PV system (see Appendix J: Modeling Assumptions Data). In sum, the forecast states that nearly 3,000 MW of DG-PV will energize our distribution systems across our companies.

With a renewed focus on customer-centric planning that will enable an advanced grid that customers can plug into, innovative planning and technologies are key components to transforming distribution systems that currently serve 1,500 MW of load, roughly half of the expected amount of DG-PV in 2045.

The transmission and distribution systems must now transition to an integrated grid; we can no longer operate and plan them as separate entities, as both ends of the electric power system will supply power. The integrated grid will enable DER to provide the services that are lost with the deactivation on traditional centralized conventional generation. With the paradigm shift to an integrated system, impacts are no longer contained to the distribution system; the sub-transmission and transmission system need to transform to accommodate our customer's desires.

We focused on identifying the problems we see today and the ones we anticipate in the near-term at all levels of the power system with respect to PV integration:

- Voltage power quality
- Conductor and equipment thermal overloads
- Operational flexibility
- Ground fault overvoltage

To solve these problems, we consider various solutions and strategies leveraging traditional solutions, emerging technologies, and advanced inverter capabilities. The ultimate solution in each case will depend on its benefits, cost, implementation time, and operability.

We developed integration costs for two DG-PV cases: the market DG-PV forecast and the high DG-PV forecast based on the April 2016 PSIP Update. Simulations of our sub-transmission and distribution system models informed the PV integration cost estimates.

Some of the solutions offered include:

Issue	Traditional (Wires)	Technology (Non-Wires)
Thermal Capacity	▪ Overhead and Underground Conductor Upgrades ▪ Distribution Transformer Upgrade	▪ Energy Storage
Voltage Power Quality	▪ Voltage Regulator Installation ▪ Distribution Transformer and Secondary Conductor Upgrades	▪ Var Compensation Devices ▪ Advanced Inverters
Operational Flexibility	▪ Circuit Re-Configuration ▪ New Circuit and/or Substation Transformer	▪ Energy Storage ▪ Advanced Inverter DER Controllability
Ground Fault Overvoltage	▪ Grounding Transformers	▪ Fast Tripping Advanced Inverters

Table N-1. Summary of Mitigation Solutions Considered

Utilizing our hosting capacity models and methodology, we analyzed high DG-PV scenarios to determine the near-term costs to integrate the forecasted PV. As policies are implemented to better align load with DER resources, the scope and magnitude of the circuit upgrades will change. Based on current circuit conditions, Table N-2 provides the costs to integrate the near-term high DG-PV forecast under different solution strategies.

Island Grid	Strategy 4: Traditional	Strategy 5: Traditional w/ Advanced Inverter Control	Strategy 6: Technology (Storage)	Strategy 7: Least Storage w/ Advanced Inverter Control	Forecasted PV
O'ahu	$102M	$145M	$212M	$92M	572 MW
Maui	$70M	$64M	$179M	$58M	126 MW
Hawai'i Island	$22M	$22M	$39M	$24M	113 MW

Table N-2. Near-Term Cost Comparison, High DG-PV Strategies, 2016-2020

In the near-term, traditional upgrades (Strategy 4) and advanced inverter control (Strategy 7) proved to be the most cost-effective options.

The Hawaiian Electric power system includes a sub-transmission system that often serves as the point of interconnection for grid-scale projects because of the geographic area that it covers on O'ahu. We conducted a preliminary hosting capacity analysis of the sub-transmission system and found one instance of overloaded conductors in the Wahiawa area, which modeled the April 2016 market DG-PV forecast and the grid-scale resources slated for installation through 2019.

A range of remaining sub-transmission capacity was then determined in the regions of high potential solar development as identified by NREL (See Appendix F: NREL Reports). Figure N-1 illustrates the sub-transmission constraints in these regions.

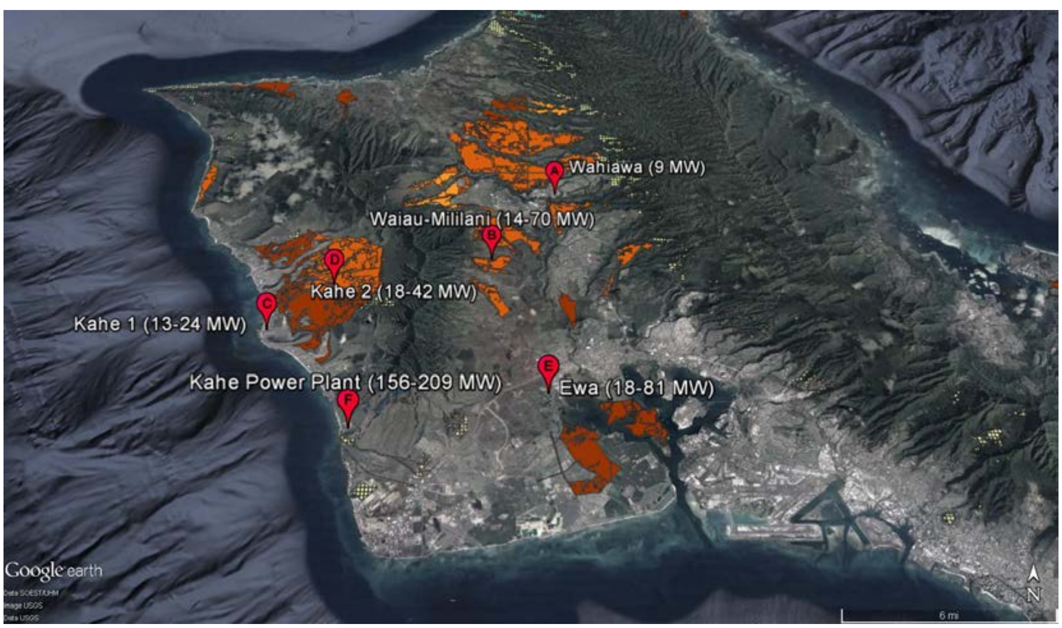

Figure N-1. Near-Term Sub-Transmission Capacity for Grid-Scale Resources by Solar Region

Once the sub-transmission system reaches capacity, we must weigh future transmission expansion against non-transmission alternatives to determine the best path forward to integrate the grid-scale and high DG-PV capacities in the mid- and long-term as laid out in these resource plans.

The technical analyses and cost implications are based on the DG-PV forecasts and grid-scale potential data available today. However, upon development of DER programs and policies and receipt of grid-scale proposals, we can better predict the market and location of resources, which in turn leads to a more accurate evaluation of the scope and cost of grid upgrades.

Customers will drive significant growth in DER. We will need to rely on innovative modeling techniques and tools to inform policymakers of the requirements for safe and reliable interconnection of customer resources. In order to achieve our goals, we will make significant investments in the grid to remedy the impacts seen today, and the impacts predicted by the transmission and distribution models for the future.

GRID MODERNIZATION MAXIMIZES A DIVERSE SET OF RESOURCES

Hawai‘i's grid modernization statute, enacted in 2013, directs the commission to "*consider the value of improving electrical generation, transmission, and distribution systems and infrastructure within the State through the use of advanced grid modernization technology in order to improve the overall reliability and operational efficiency of the Hawai‘i electric system.*"[1]

Consistent with the statute, we will identify grid modernization investments that, (1) maximize cost-effective interconnection of distributed energy resources and grid-scale resources, (2) maintain and enhance grid operating reliability and safety, (3) seek improved efficiencies in grid operations and interoperability, and (4) create an integrated grid through advanced planning, forecasting and operations.

We will modernize the grid through foundational technologies, an expanding range of energy innovations, traditional solutions, and new grid services. Foundational technologies such as advanced metering, a demand response management system, and an advanced distribution management system will replace exiting grid management tools built for one-way power flow. New management systems provide operators visibility into resources on the distribution system beyond the substation fence, to make better operational decisions. In combination with grid investments such as conductor upgrades, these technology platforms will facilitate two-way power flow.

Table N-3 summarizes our grid modernization efforts currently underway through various pending dockets, on our roadmap, or as discussed in this PSIP update.

[1] Hawai‘i Revised Statute §269-145.5.

Grid Modernization Investments		
Element	Description	Benefits/Grid Modernization Value
Grid Modernization Efforts that Indirectly Enable the PSIP Resource Plans		
Advanced Metering Infrastructure (AMI)	More than an automated meter reading device. Metering infrastructure that informs customers and utilities in real-time, a customer's energy consumption and power quality (for example, voltage).	■ Provide customers access to energy use and information. ■ Enables time-of-use and real-time pricing programs. ■ Provides system operators and planners needed visibility to grid operations and power quality at DER point of interconnection. ■ Enables two-way communication and control of smart home appliances and devices.
Distributed Energy Resource Management System (DERMS)/Demand Response Managements System (DRMS)	A single integrated platform to manage DR and DER resources. This will allow information exchange, management, and dispatch of resources.	■ Facilitate integration and management of DR and DER and their associated grid services otherwise provided by the utility. ■ Improved grid operations and flexibility through aggregation services, load and curtailment forecasting, among others.
Advanced Distribution Management System (ADMS)	An operational software platform that manages smart field devices, enhances outage management and operational capabilities, and provides operators additional grid insight.	■ Improved efficiencies in outage planning and operations through better analytics of the grid enabled by DA/Substation automation.
Distribution Automation (DA)/Substation Automation	Modernization of substations through telemetry and advanced protective relaying. Distribution automation with installation of remote fault current indicators, Intelligent switches, and sectionalizing devices.	■ Increased situational awareness through substation telemetry. ■ Improved grid reliability and resiliency (outage response) will maximize DER production and reliability.
Modern Communications Network	A network architecture that combines wireless networks and fiber optics equipped with the bandwidth to support the transmission of system SCADA data, intelligent field device control, DER command and control, AMI real-time data and smart home device control, among others.	■ The platform in which various communication mediums (3rd party aggregator, wireless field area network, lease line fiber) combine to support two-way communication and the interoperability of the advanced grid and its assets.
Interconnection Improvement Program (IIP)	Online web portal to manage the application process to DER programs for customers.	■ Facilitates an efficient interconnection process for customers and integrated grid forecasting and planning for the utility.
Advanced Planning and Forecasting Tools	Enhanced forecasting and DER profiles through data analytics for advanced modeling and operations.	■ The visibility AMI, ADMS, and DERMS will provide improved forecasting and modeling accuracy. ■ Advanced and innovative modeling tools and techniques will be needed to transition to an integrated grid where significant generation and grid services are provided from the T&D systems.

Grid Modernization Investments		
Element	Description	Benefits/Grid Modernization Value
Grid Modernization Efforts that Directly Enable the PSIP Resource Plans		
Volt-var Optimization (VVO)	A technique to manage distribution voltages and reduce energy consumption while mitigating high voltages caused by PV. Devices such as static var compensation devices enable this.	■ Enables integrated voltage control on the distribution system, which will increase hosting capacity and reduce inefficiencies. ■ AMI and visibility of DER are key components that enable VVO.
Advanced Inverters	Power electronic devices that enable distributed resources to provide grid support services.	■ Resources such as PV and energy storage can provide grid services for the bulk system and distribution system to maximize DER deployment. ■ Communication network and DERMS are critical to managing and configuring the inverters for optimal operation and dispatch.
Synchronous Condensers	A synchronous machine that does not produce active power but instead reactive power.	■ Will stabilize the grid by replacing inertia, fault current, and reactive power support that conventional generation previously provided.
Contingency Energy Storage	Energy storage that can provide grid services such as fast frequency response and primary frequency response.	■ With the deactivation of conventional generation and the increase variability of solar and wind, fast frequency responding resources will be needed for operating reliability and stability.
Load Shifting Energy Storage	Cost-effective deployment of energy storage that can provide the grid generating capacity and regulation.	■ Directly enables DER and grid-scale integration by shifting energy to when the grid needs it most while adding value with the stacking of regulating reserve services.
Conductor Upgrades	Targeted deployment of conductor upgrades to the distribution system that increase capacity for DER integration. With high penetrations of PV on the distribution system, these upgrades will re-configure the traditional radial system (large wire sizes at the beginning of a circuit, smaller wires at the end).	■ AMI, DERMS, DER and communications network will smartly manage energy and partially offset traditional grid upgrades. However, selectively targeting "heavy" grid upgrades will maximize DER production and minimize energy losses and inefficiencies.
Transmission System Expansion	Provide grid-scale resources access to the transmission system through the expansion of the existing transmission substations at Kahe and Wahiawa, new transmission substations in the Lualualei and Helemano areas, and new transmission lines at N-1-1 reliability will allow the grid to maximize the solar and wind potentials on the west and north sides of O'ahu.	■ To accommodate the significant solar and wind potentials, as studied by NREL, on O'ahu, we will need additional capacity to deliver power to the east side of the island, and provide operators the flexibility to re-direct power flows.

Table N-3. Grid Modernization Investments

Together these initiatives will enable the integrated grid that utilizes resources from the transmission system to a customer's rooftop. We continue to prioritize smart energy management of renewable resources as a means to reduce grid investments; however, platforms such as AMI, DERMS, and ADMS will further enable higher DER penetration. For example, advanced meters provide the visibility planners need to realize efficiency improvements in the interconnection process. Once interconnected, the modern communications network coupled with the DERMS and ADMS will allow the operator to better manage the power flows on the distribution system and avoid a substation upgrade. Distribution automation and an ADMS will result in quicker outage restoration times, which will maximize the availability of customer resources that are now depended on to meet the grid's total energy needs. Maintaining the reliability of the distribution system, which will contain over 2,000 MW of PV, is critical to the stability of the power system.

These complementary set of grid modernization efforts play a significant role in moving Hawai'i to 100% renewable energy.

OUR VISION TO CREATE A GRID PLATFORM FOR ALL CUSTOMERS

We believe our expertise as the grid operator for the past 125 years puts us in a unique position to enable the gird platform needed to maximize the adoption and utilization of advanced DER technologies. Customers have come to expect from us: safe and reliable service, standby electric service, timely restoration following a weather event, and a high standard of power quality. The complexities of the grid have not stopped us from delivering those services.

We seek to improve on those services customers are accustomed to, while developing the platform that enables us to be the primary grid integrator. Creating an ecosystem of DER technologies that facilitates efficient energy transactions will benefit all customers as we make investments to modernize the grid.

We will accomplish this with the use of rapidly advancing technologies to manage the grid—advanced energy management, a smart grid, and a communications network that supports the interoperability of an assorted mix of distributed assets.

We envision customers seamlessly making energy choices that serve their own energy needs while benefiting the overall grid. Customers can choose to charge their EV where they work or live; place PV on their rooftop or invest in a community project; invest in storage that aligns with the system needs; allow system operator control of non-critical loads.

New Concepts to Provide Operating Reliability

Operating reliability (or system security), is the ability of the electric system to withstand sudden disturbances such as electric short circuit faults or unanticipated loss of system components. We will integrate large quantities of variable wind and solar into our island grids, displacing traditional conventional central station generation. Although DER, to a certain extent, can reduce losses and loading constraints, the de-committing of conventional generation offsets those benefits because the system loses voltage control, short circuit availability, inertia, and primary frequency response services. Conventional generators provided multiple grid services that secured the gird; replacing these services with multiple assets will require innovative planning and operations.

Frequency support is required to stabilize frequency on the synchronized grid and to maintain continuous load and resource balancing by deploying automatic response functions in response to frequency deviations. Under pre- and post-contingency conditions, system operators must have the ability to raise or lower generation or load, automatically or manually. Alternatively, we can carefully deploy autonomously responding resources, not under the visibility and control of the utility, to maintain the balance of the grid, while not compromising system security.

Voltage support and short circuit availability is required to maintain system level voltages on the grid within established limits, under pre- and post-contingency situations; thus, preventing voltage collapse, system instability, or delayed fault clearing. The increased voltage support and short circuit current will strengthen the grid making it better able to withstand disturbances.

Some of the Companies' technical strategies for operating reliability are outlined in Table N-4.

Issue	Current Methods	Future Methods
Frequency Support:	▪ Inertia is the stored rotating energy in a power system provided by online synchronous and induction generation operating at least their minimum power output level. ▪ Primary frequency response (droop) is the automatic corrective response of the system, typically provided by synchronous generation, to react or respond to a change in system frequency. ▪ Spinning reserve is typically provided by synchronous generation that is ready to ramp up or down in response to a frequency deviation. ▪ Demand response is the reduction of load to balance loss of generation triggered at a predetermined frequency set point and limited by program participants. ▪ Under frequency load shed scheme is the automatic disconnection of blocks of load to re-balance the system during a frequency disturbance.	▪ Synchronous condensers and flywheels to provide inertia. ▪ Fast frequency response resources such as batteries, flywheels, curtailed PV and wind energy that can respond in cycles, upwards, by injecting energy into the grid. ▪ Demand Response resources (with fast frequency response characteristics) that can respond within a specified time adequate to correct frequency imbalances. This can be reductions in load or injection of real power from DER aggregated into a controllable and quantifiable program to respond to under frequency events, or a fast injection of controllable load in response to an overfrequency event. ▪ Autonomous downward response of inverter based DER resources configured with the advanced inverter frequency-watt function to respond to an overfrequency event.

Issue	Current Methods	Future Methods
Voltage Support/Short Circuit Availability	▪ Reactive power supply and voltage control provided by synchronous generating facilities, excitation systems, and capacitors. ▪ Protective relay schemes designed to isolate faults within cycles. ▪ Fault current supplied by synchronous generators. ▪ Dynamic reactive power capability of synchronous generators and static var compensators.	▪ Synchronous condensers to provide reactive power support and short circuit current. Repurposing de-activated generators as condensers. ▪ Storage systems such as battery storage, electric vehicles, flywheels, and thermal storage to provide quick and flexible energy sources to stabilize system balancing.

Table N-4. Strategies for Maintaining Operating Reliability

New Distribution System Supports Customer Choice and DER Connection

We envision an advanced distribution system where customers can plug their distributed resources into the grid. The grid will provide the overall operating safety net for all customers and supervision of DER so that power quality and reliability meets their needs. An expanding portfolio of new energy technologies and services will support the grid while it continues to provide efficient electric service.

The diverse set of resources – battery storage, electric vehicles, thermal storage, and PV – located on the low voltage system will require advanced planning solutions to predict and resolve their impacts. We will adopt old and new best-fit solutions to grid constraints. Table N-5 describes some of the solutions to resolving capacity, voltage power quality, and operational flexibility issues.

Issue	Traditional (Wires)	Technology (Non-Wires)
Thermal Capacity	▪ Overhead and underground conductor upgrade to relive capacity overloads from excess load or generation. This can also mitigate high and low voltage. ▪ Distribution transformer upgrade to relieve equipment overloads during peak load or generation periods.	▪ Energy Storage can play the role of energy shifting by relieving daytime congestion caused by PV to shave the evening peak should a distribution system have a peak capacity issue.
Voltage Power Quality	▪ Voltage regulator installation can control voltage by adjusting to changes in load and generation. Installation of line regulators in weaker circuit areas can mitigate the effects of rising voltages during PV production. ▪ Distribution transformer and secondary conductor upgrades can alleviate voltage rise on the secondary level that occur during light load and high PV periods. Performing this upgrade reduces the impedance between the inverter and the distribution transformer.	▪ Var compensation devices are devices that act faster than traditional voltage regulators and can provide reactive power capabilities to positively influence feeder voltage. ▪ Advanced inverters can provide reactive power control to positively influence voltage.

Issue	Traditional (Wires)	Technology (Non-Wires)
Operational Flexibility	■ Circuit re-configuration can help to rebalance loads and generation between circuits to maintain the N-1 planning criteria and operational flexibility. ■ New circuit and/or substation transformer when generation backfeeds at the substation violates the N-1 planning criteria then new substation capacity must be built to maintain the distribution system's integrity and flexibility. This is similar to serving a distribution system's peak load.	■ Energy Storage can limit the amount of energy exported at the substation by storing energy in excess of the N-1 planning criteria. ■ Advanced inverter DER controllability will allow system operators to manage the resources during abnormal conditions. For example, grid-scale projects have controls that allow system operator to control its active power output when safety and reliability are at risk.

Table N-5. Strategies for Resolving Distribution-Level Impacts

DISTRIBUTION SYSTEM OVERVIEW AND THE PLANNING PROCESS

The distribution system is the part of the electric power system that distributes or disperses power from the transmission system to individual customers. To deliver electricity to spatially diverse customers, engineers must strike the appropriate balance between reliability and power quality in order to design an economically viable distribution system.

The term "one-way power flow" often describes the traditional method of power system design. One example of one-way power flow refers to the architecture of the distribution system. Our distribution systems are predominantly designed as a radial system; that is, starting at the substation the distribution circuit is designed to handle greater capacity (or bigger wires) and tapers outward (or designed with less capacity, smaller wires) as the system distributes power to customers farther away from the substation. In other words, the capacity of the distribution circuit closest to the substation is the greatest, as it must have the throughput to push power to all customers on a circuit. As one moves towards the end of a circuit (farther away from the substation), there are less customers left to serve; therefore, less capacity or throughput is required. As customers add solar to their rooftops deeper into the distribution system, the smaller wires at the end of the circuit may lack the capacity to accommodate excess energy that flows back towards the substation.

One major component of the distribution system (Figure N-2) is the distribution substation; this is the point in the electric power system where the transmission or sub-transmission system delivers power at high voltages and converts the power to medium voltage for distribution of power at safer and more economical means. Our distribution systems consist of 2,400-volt, 4,160-volt, 11,500-volt, 12,470-volt, and 24,940-volt systems; these voltages are also known as the primary part or primary voltage of the distribution system. The substation transformer generally supplies power to two circuits (or feeders) that serve as the means to deliver power to customers—circuits are identifiable as poles and wires at the side of a road. Higher voltage distribution circuits have more capacity than lower voltage distribution systems. The lower voltage distribution systems—2,400 volt and 4,160 volt—are at higher risk for power quality and capacity issues. Often times, these issues are resolved by converting these circuits to a higher voltage, such as 12,470 volts.

The final major component of the distribution system is the distribution transformer, sometimes referred to as the service transformer. This piece of equipment converts the medium voltage, 2,400 through 24,940 volts, to a lower voltage, 120/240 volts for final delivery to customers. The majority of appliances and devices used by consumers operate at 120 or 240 volts. Residential customers normally share a distribution transformer, and receive power via wires that branch out from the transformer to each individual home. Larger customers who have bigger load requirements often have a dedicated transformer and service connection.

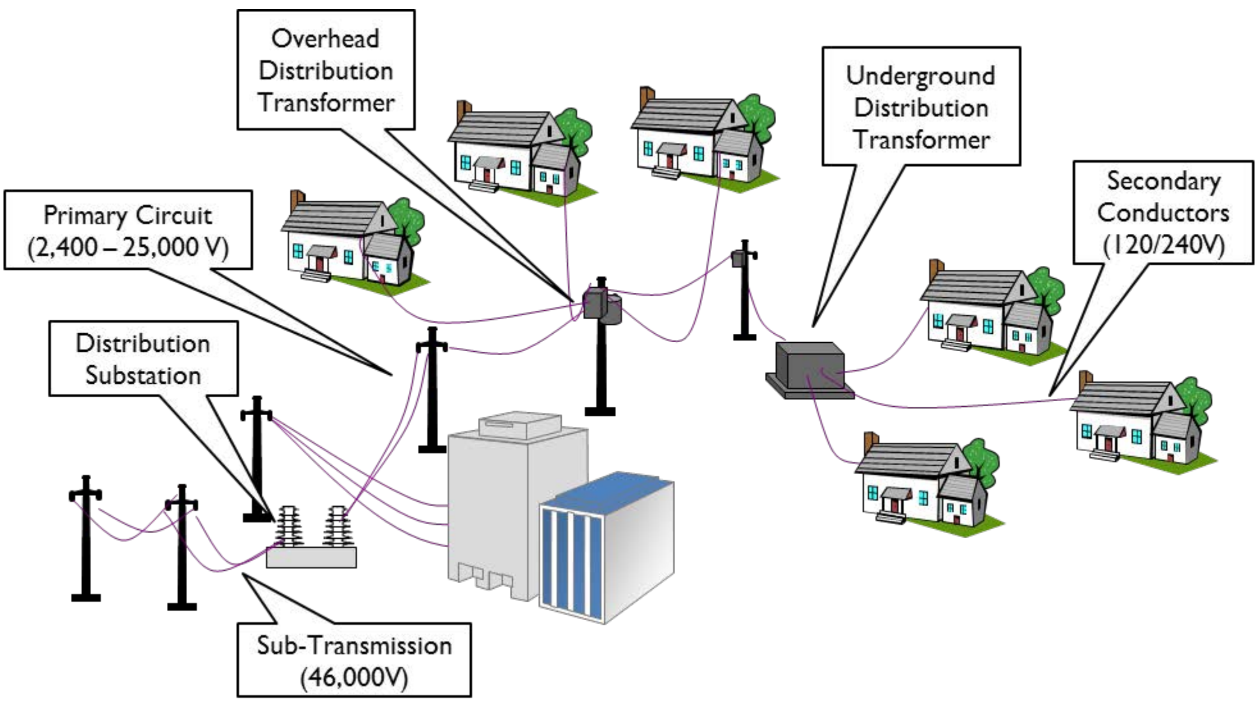

Figure N-2. Major Components of the Distribution System (Illustration)

To ensure the reliability of electric service to all customers, radially fed circuits have ties to adjacent circuits. The tying of circuits within the distribution system provides system operators the flexibility to reconfigure the distribution system to restore power during a contingency event – planned or unplanned outage. Distribution planners also reconfigure circuits to maintain reliability and power quality for customers; for example, significant load growth may create power quality or capacity issues, in which case, a portion of a circuit permanently transfers to another circuit to avoid overloading equipment or degrading power quality.

Figure N-3 illustrates the operational flexibility concept. Should a substation be taken out-of-service, planned or unplanned, a neighboring substation can restore power by closing a switch that ties the two circuits together, but normally open during normal operations.

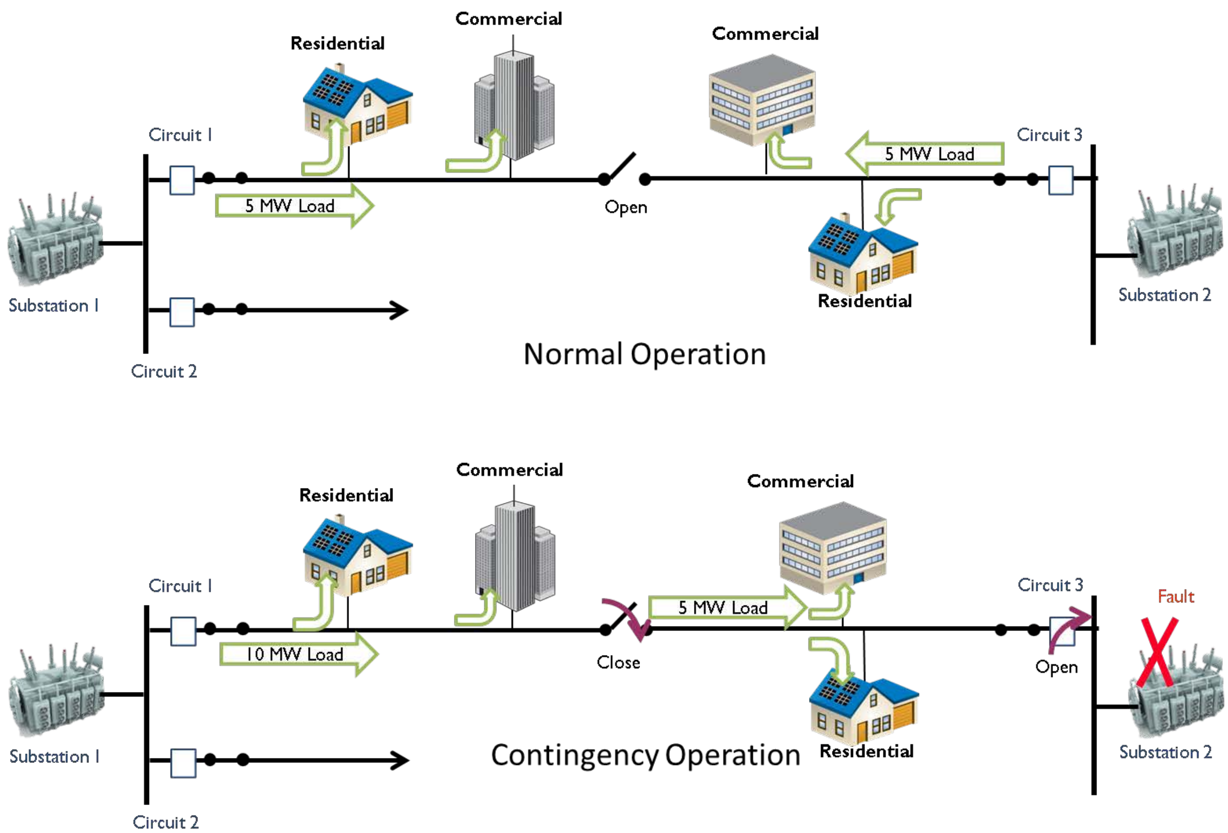

Figure N-3. Operational Flexibility (Illustration)

Maintaining this operational flexibility is critical to our ability to provide continuous electric service.

Distribution Planning

On an annual basis, Distribution Planning conducts Substation Load and Capacity Analysis (SLACA) of the distribution system. This entails analysis of the previous year's substation transformer loading data—from our SCADA system, if available—to examine whether the highest peak load observed at the substation transformer violates distribution planning criteria. That is, a substation transformer shall have the capacity to not only accommodate the highest peak demand and any forecasted load growth, but also accommodate the load from the loss of a neighboring substation transformer (N-1 reliability) based upon the greater of the transformer loss-of-life rating, protective fuse rating, or cooling rating. Simply put, these ratings are the thermal limit of the transformer. Failure to meet this criterion may result in accelerated equipment failure.

There are normally multiple ties between circuits that provide system operators the ability to expediently restore power without risk of damaging equipment. To understand this concept, we can apply a rough rule of thumb; at peak load conditions, transformers are loaded to 50% of its rated capacity. In other words, a reserve margin of 50% of the transformer capacity is maintained during normal circuit configurations or operations to provide the operational flexibility of the system. This 50% reserve margin is then used to accommodate the load (or reverse power from PV) of a neighboring out-of-service substation transformer during an outage event.

It is common for the configuration of the distribution system to change from year to year; this also affects PV hosting capacities. The following factors drive the dynamic nature of the distribution system: changing customer behavior, load growth, load imbalances, or degradation of power quality.

Upon completion of the SLACA analysis, Distribution Planners address any planning criteria (including loss of operational flexibility) violations. Planners first seek the most efficient, least cost strategy; for example, permanently reconfiguring a circuit by transferring load from a substation that exceeds the 50% capacity threshold to a neighboring substation that is loaded less than 50% can cost-effectively restore operational flexibility. If least cost solutions fail to resolve the planning criteria violations, Planners seek longer lead, more costly solutions; for example, the construction of a new substation to create capacity. Planners determine load growth by new customer service requests, economic or land development projections, and load trends. Unlike mainland utilities, the SLACA analysis is not completed seasonally. Hawai‘i does not see significant load variations between winter and summer months, nor do we benefit from increased capability of utility equipment due to cooler ambient temperatures.

Distribution Planning also performs similar capacity analysis on the sub-transmission system, utilizing a similar process to resolve capacity issues.

Distributed Energy Resource Planning

Distributed Energy Resource (DER) planning and the exponential PV growth experienced within the last couple of years have evolved the traditional distribution planning process. We recently employed a process and methodology to perform hosting capacity analysis to more appropriately predict and plan for the integration of DG-PV. As shown in Figure N-4, almost 50% of the distribution circuits have more PV than the daytime minimum load; reverse flow is commonplace on Hawai‘i grids. This is not the case for other systems throughout the United States.

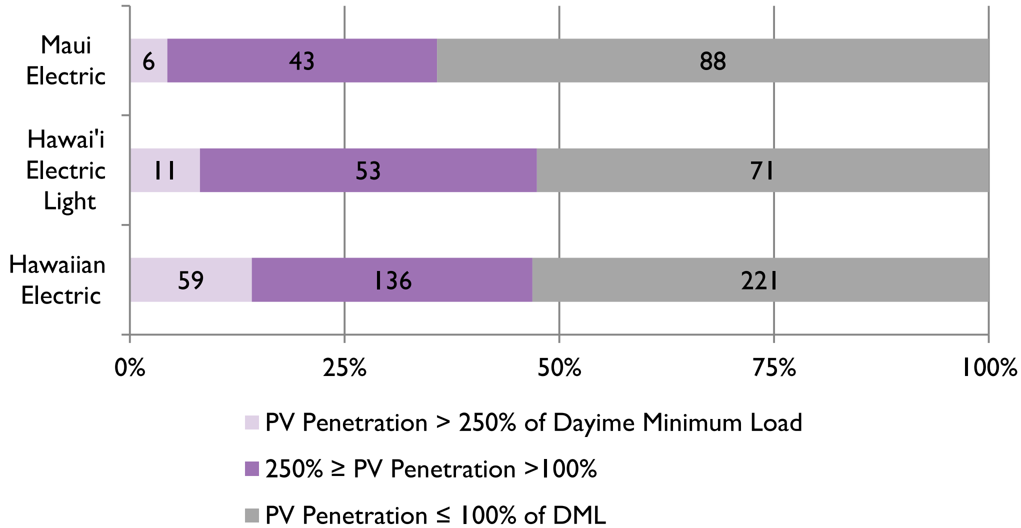

Figure N-4. Circuit PV Penetration by Daytime Minimum Load

Based on previous high DG-PV penetration studies we have conducted, coupled with field experience, the hosting capacity analysis evaluates (1) voltage power quality, (2) equipment and wire capacity, and (3) operational flexibility. Undoubtedly, there are many more potential impacts that can affect the safety, reliability, and power quality of electric service to all of our customers, but these three issues are of the utmost immediate near-term concerns. As part of the hosting capacity analysis, an Operational Circuit Limit is also determined. This limit defines the reverse power threshold at the substation to maintain the operational flexibility of the circuit—the same principle described as part of the Distribution Planning process above.

A PV system's impact to a distribution system is highly dependent on its actual location with consideration of a number of factors: load, circuit impedance, neighboring PV systems. The hosting capacity analysis, through software simulation and analytics, determines the amount of PV a circuit can accommodate, regardless of location, before violating one of the three criteria discussed above. The interconnection of PV above that hosting capacity may incur capital improvements to mitigate any expected impacts. More details regarding the hosting capacity analysis are in the document titled, *Rooftop PV Interconnections: A Methodology of Determining PV Circuit Hosting Capacity* filed in Docket No. 2014-0192, on December 11, 2015.

As earlier discussed, Planners plan the distribution system based on the peak demand of a circuit. However, with the introduction of PV, distribution system planning must now account for minimum load, high generation periods in addition to the traditional evening peak period.

Under the net energy metering program, it was common practice for customers to size PV systems to offset their annual energy usage; the unintended technical consequence of this practice results in energy exports greater than the customer's typical peak load, which the distribution system was originally designed to accommodate. Consequently, during solar peak hours and daytime load levels, the peak export of energy onto the distribution system is greater in magnitude and more coincident than a customer's evening peak load. This increased power flow during minimum load periods will create power quality and capacity impacts that must be addressed before integrating high amounts of PV. Figure N-5 illustrates this point; a customer with the average 6 kW PV system will zero-out his or her annual energy usage. This equates to an average monthly consumption of 806 kWh (531 kWh per weekdays per month). On a typical residential load profile, this energy usage equates to a peak demand of 2.3 kW. During daytime minimum loads, when this customer is not home, the PV exports up to 4.5 kW. During daytime hours, the load flow on the secondary part of the system is 4.5 kW, as opposed to its previous peak loading of 2.3 kW in the evening; nearly double the normal peak loading. This amount of exported energy exceeds any design margins of the distribution system.

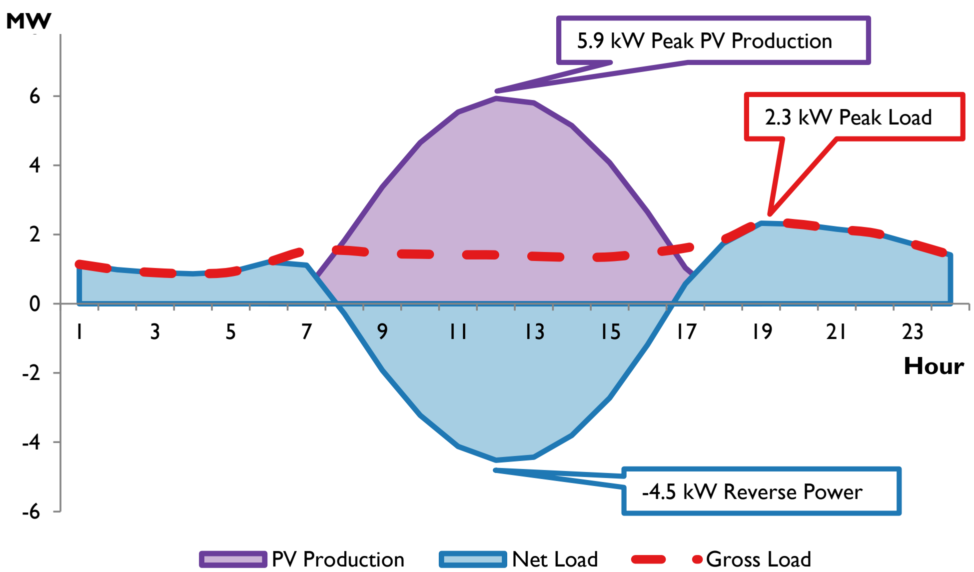

Figure N-5. Typical Weekday Residential Customer Load Profile

The lack of PV production diversity as compared to the load diversity seen during the evening peak load creates PV integration challenges on the distribution system. Load diversity and the non-coincident behavior of customers allow distribution planners to plan the distribution system under peak demand conditions with certainty that customers will not simultaneously consume power at their peak; the distribution system is designed to accommodate diversified customer load—not the maximum potential load. For instance, a service transformer serving 10 homes typically has a diversity factor[2] as much as 45%. In contrast, PV systems lack the same type of diversity as all PV production is a function of the sun's irradiance and not a function of diverse human behavior. Diversity from the placement, angle, and direction of a PV system equates to roughly 75%–85% of the maximum capacity, not nearly the same overall reduction as load diversity. Put another way, the sun does not shine when customers are consuming the most electricity.

By necessity, the hosting capacity analysis will develop into a more dynamic and granular analysis, as battery, electric vehicle, and the deployment of other distributed resources continue to grow. Battery standards that recognize a battery's unique characteristic of functioning as a load and generator will be established to create grid positive benefits; charging when the system most needs load, discharging when it most needs generation—in steady-state and transient conditions.

As the State continues to electrify transportation, electric vehicle charging should coincide with system needs as to not impress undue strain on utility equipment and operations. The dynamic hosting capacity models should integrate these behind the meter distributed energy resources to efficiently, design, plan, and operate the distribution grid.

DISTRIBUTED PV INTERCONNECTION IMPACTS

With an added emphasis on customer-sited distributed resources, and an expectation that by 2045, customers would supply over 2,400 MW of PV and nearly an equivalent amount of grid-scale resources, the impacts are no longer contained to the distribution system. Other components of the power system will require evaluation and proactive mitigation to ensure continued safe and reliable service for our customers.

Distribution System Impacts

This iteration of the PSIP includes a forecast that significantly increases distributed rooftop PV. It is anticipated that the following impacts will continue to grow:

- Voltage power quality/regulation (high and low voltage)
- Conductor and equipment thermal overloads
- Operational flexibility (operational circuit limit)

[2] Diversity factor is the ratio of actual coincident peak load to the sum of all customers' non-coincident peak load. For example, the total non-coincident peak load for 10 homes may be 100kW, but at any given time the total loads that must be served by the utility 4.5kW. In other words, not all homes are running its water heater, oven, and other appliances at the same time.

Future analysis and continued power quality monitoring of the distribution system will ensure other PV impacts such as flicker, imbalance, protection, among others, do not occur[3]. The three impacts listed above represent the near-term concerns based upon model simulations and field data.

As discussed in *Rooftop PV interconnections: A Methodology of Determining PV Circuit Hosting Capacity* filed in Docket No. 2014-0192 on December 11, 2015, our analysis of the Companies' distribution system concluded that continued PV growth will require solutions to mitigate voltage power quality, conductor and equipment overloads, and operational flexibility deficiencies. For example, we have recorded high voltage conditions caused by PV. Figure N-6 illustrates one real-world example where PV caused voltage to rise during daytime hours:

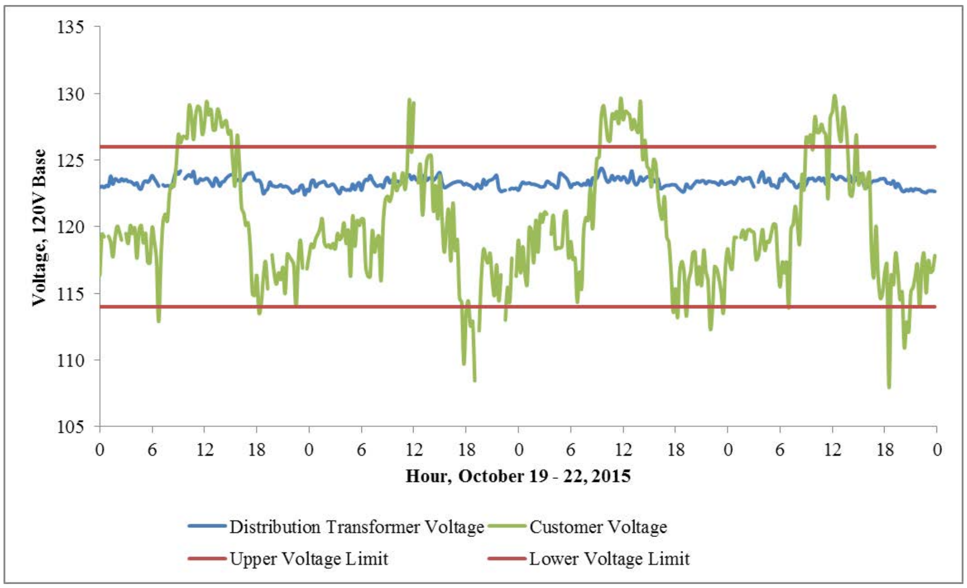

Figure N-6. Customer Meter Voltage Readings and the Serving Distribution Transformer

Figure N-6 presents actual data captured at the distribution transformer and the customer's meter. This particular customer installed a 10 kW PV system which clearly caused voltage to rise during the peak solar hours (that is, noon), as compared to the voltage seen at the distribution transformer (monitoring point). The approximate 6–7 volt rise seen between the monitoring point (blue line) and the customer (green line) caused the customer's PV to violate the prescribed voltage limits of national standards and Hawaiian Electric power quality rules. To resolve this issue, Hawaiian Electric executed a $14,000 project to install an additional (new) distribution transformer closer to this customer's house to reduce the distance between the distribution transformer and the

[3] High-Penetration PV integration Handbook for Distribution Engineers Seguin, Woyak, et. al. NREL/TP-5D00-63114. January 2016.

customer's house; thereby, reducing the voltage rise to within acceptable standards (depicted in Figure N-7).

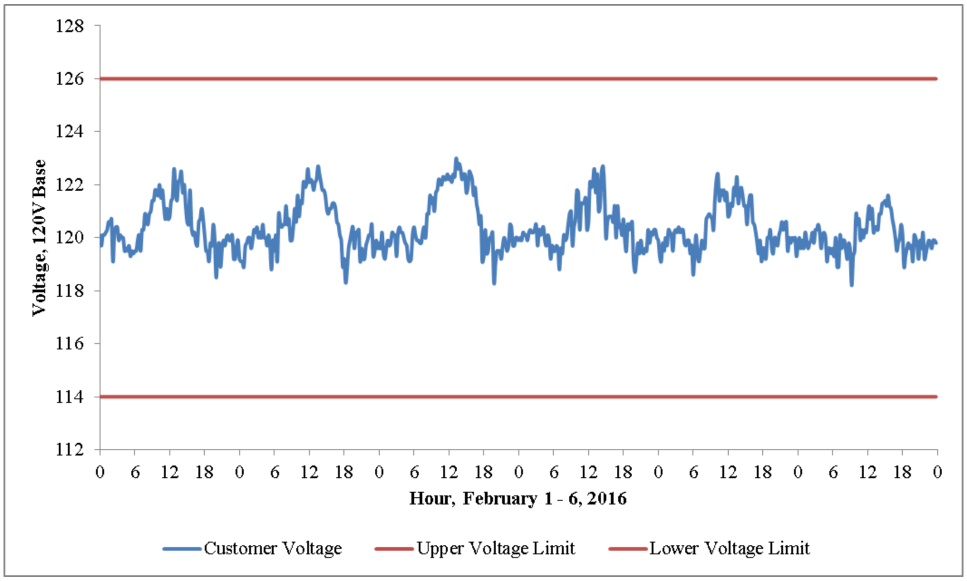

Figure N-7. Customer Meter Voltage Readings After Secondary Overvoltage Mitigation Installed

Although Figure N-6 shows that low voltage occurrences are infrequent, the high voltage "humps" during the middle of the day have expanded the total voltage range (from peak to trough of the green line) between 8 and 10 volts. This is significant because it eliminates "headroom" or reserve margins we previously retained to ensure voltage stays within the prescribed limits. Before having PV on the distribution system, we utilized the voltage headroom to prevent low voltage by shifting the voltage band upwards. The high voltage conditions caused by PV have cut into the margins we previously maintained.

Sub-Transmission PV Impacts

Hawaiian Electric's power system, unlike the Maui Electric and Hawaiʻi Electric Light grids, includes a true sub-transmission system, which transmits electricity from the bulk generation and transmission system to the distribution system.

The Hawaiian Electric grid contains a radially fed 46,000-volt sub-transmission system. In a radial configuration, customers experience a momentary outage during a sub-transmission fault while the primary source switches to the back-up source (Figure N-8). During these disturbances, DG-PV and sub-transmission connected generation will electrically trip offline, similar to a transmission line fault. The Hawaiian Electric sub-transmission and transmission system experienced 219 momentary or sustained interruptions in 2015. These interruptions directly affect the reliability of grid-scale and residential rooftop PV connected to the sub-transmission and distribution systems.

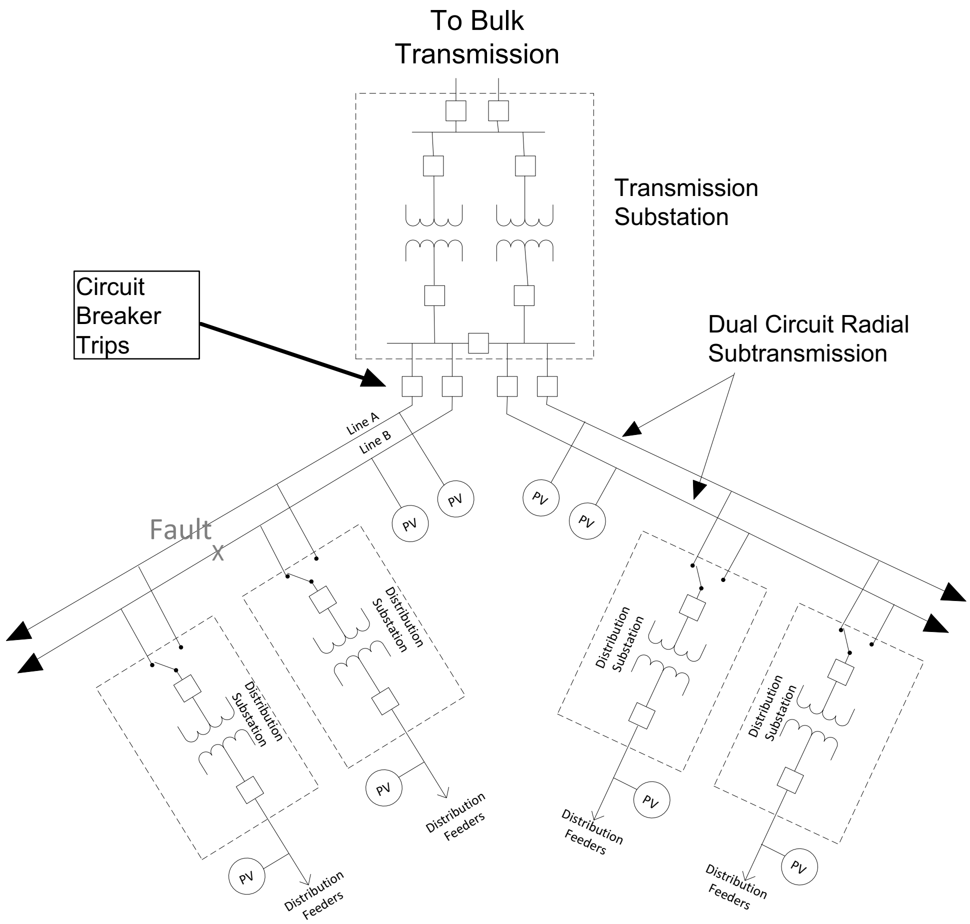

Figure N-8. Illustration of a Radial Sub-Transmission System

Similar to the distribution system, and based on past interconnection requirements studies for grid-scale projects, and a recently completed preliminary sub-transmission hosting capacity analysis, the following are anticipated impacts to the sub-transmission system:

- Conductor and equipment overloads
- Operational flexibility
- Ground fault overvoltage
- Voltage power quality / regulation

The preliminary analysis, which included the April 2016 market DG-PV forecast for 2045, and past studies indicate that conductor capacity is the primary limitation to interconnection. The maximum capacity on a single sub-transmission line is 55 MVA, the largest overhead conductor size at 46,000 volts.

Operational flexibility is less of a concern with grid-scale resources than distribution connected projects because system operators have direct control of projects greater than

250 kW at Maui Electric and Hawai‘i Electric Light, and 1 MW at Hawaiian Electric. This allows operators to adjust a PV plant’s output during emergencies, abnormal, or contingency situations.

Recent interconnection studies have determined that ground fault overvoltage will require mitigation. The recent studies analyzed six different sub-transmission lines for ground fault overvoltage. Of the six lines, four of the circuits had a penetration of at least 120% of daytime minimum load; all four demonstrated a violation of the ground fault overvoltage threshold, which is determined by the withstand rating of our lightning arrestors.

Ground fault overvoltage can occur from a sub-transmission fault where the feed-in of fault current from the PV systems on the distribution system create a neutral-shift, ground fault overvoltage. Failure to address ground fault overvoltage would result in damage to utility lightning arrestors, and any sub-transmission loads connected single-phase to ground.

We conducted an inverter ground fault overvoltage study with the National Renewable Energy Laboratory[4] to study the inverter behavior during single line to ground faults. While the tests were positive for distribution-level faults (wye-ground: wye-ground transformer configurations), testing of sub-transmission faults (delta-wye-ground transformer configurations) was inconclusive as to whether inverters will cause damaging ground fault overvoltage.

Transmission System PV Impacts

The transmission system is the optimal interconnection point for large generation because of the increased capacity and reliability relative to the distribution and sub-transmission system. The transmission system on O‘ahu at 138,000 volts can carry significantly more capacity then the sub-transmission system (430 MVA versus 55 MVA). Additionally, Hawaiian Electric designs the transmission system for N-1-1 reliability and at Maui Electric and Hawai‘i Electric Light, N-1 reliability. Hawaiian Electric designs its sub-transmission system for N-1 reliability. The expected transmission issues discussed here relate to the physical interconnection of grid-scale resources. Appendix O: System Security Analysis includes a more comprehensive analysis of the transmission system impacts, specifically, system security constraints.

Wahiawa Transmission Constraint

Two transmission lines serve the Wahiawa Substation on O‘ahu. Historically, when one of the lines is out of service for maintenance and the remaining line unexpectedly trips

[4] Hoke, Nelson, et al (August 2015). *Inverter Ground Fault Overvoltage Testing*. Golden, Colorado: National Renewable Energy Laboratory, TP-5D00-64173.

out of service due to a fault, the substation becomes de-energized, thereby resulting in the loss of approximately 40 MW to 130 MW of load depending on the time of day. This N-1-1 contingency is part of the Hawaiian Electric Criteria for Transmission Planning.

With the proliferation of grid-scale and distributed renewable generation throughout the distribution system, equipment failure contingencies, which previously resulted only in the loss-of-load, could potentially result in a loss of large aggregate generation that may result in system instability.

There is currently up to 98 MW of wind generation that flows through the Wahiawa Substation. An additional 50 MW firm generation plant (Schofield Generating Station) plans to connect to Wahiawa Substation in the near future. The total generating capacity from the existing wind generation and Schofield Generating Station connected to the Wahiawa Substation will be approximately 148 MW. Assuming a minimum loading of 42 MW at the Wahiawa Substation, the maximum net generation supplied from Wahiawa Substation to the grid can reach 106 MW.

The current largest loss of generation contingency for O‘ahu is AES at 200 MW, which has resulted in three blocks of load shed in actual recent AES outage events. In order to limit the size of the largest loss of generation contingency to 200 MW in the future, the amount of additional generation capacity at the Wahiawa Substation should be limited to 94 MW.

Kahe Constraint

At the Kahe 138,000-volt switching station, power delivery to the east side of the island is constrained by the N-1-1 planning criteria. Based on PSSE power flow analysis, the worst N-1-1 contingency occurs when the Kahe-Waiau and Kalaeloa-Ewa Nui transmission lines are out of service, and the CEIP-Ewa Nui transmission line overloads (Figure N-9).

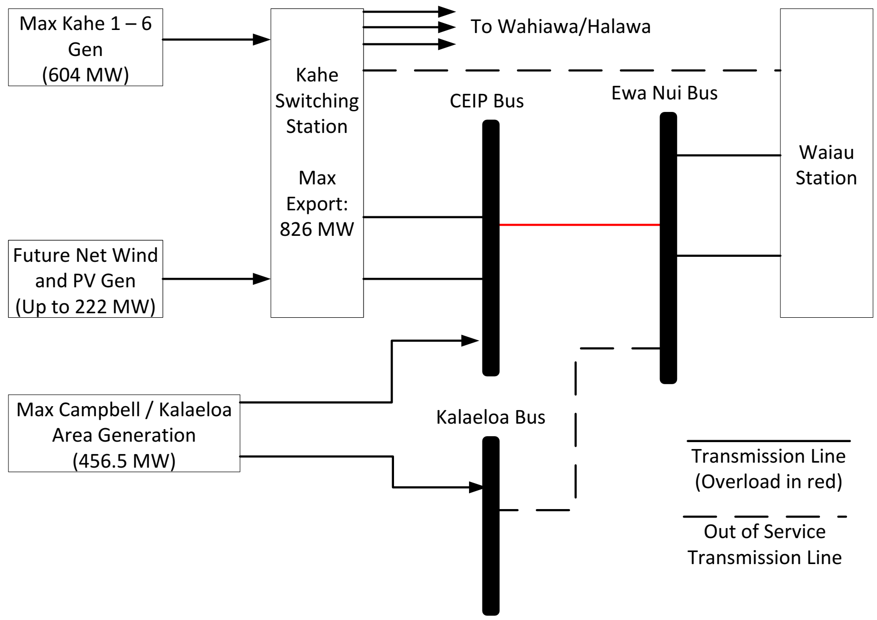

Figure N-9. Power Export Limit to the Eastern Part of the Island of O'ahu

The maximum export from Kahe switching station to serve loads east of Kahe is 826MW. This assumes 900MW of generation at the Kahe Power Plant and 74MW load at Kahe switching station.

The six Kahe generating units account for a maximum generation of 604 MW; there is room for an additional 222 MW of generation that can interconnect to the sub-transmission lines at the Kahe switching station bus.

New generation projects on the west side of O'ahu could potentially face capacity constraints until generating units at Kahe or AES are retired.

As more generation (including battery energy storage) is shifted to the west and north side of O'ahu (as the Waiau generating units are deactivated and the load center remains east of Ewa), load flow studies will continue to be required to ensure there is sufficient transmission capacity to export power to serve the urban load center.

Ancillary Services

High DG-PV scenarios on the distribution system may preclude distributed resources from providing certain ancillary services because distribution equipment will operate at, or near capacity. For example, if a transformer is at capacity to accommodate PV production during the day and the system needs fast frequency response, there is no additional capacity to accommodate the injection of power from this frequency service. However, reserving capacity or scheduling active power production as part of a demand response program will create the necessary capacity to provide those services.

DISTRIBUTION INTEGRATION METHODOLOGY, SOLUTIONS, AND COSTS

The development of integration plans and costs for the two DG-PV forecasts followed a five-step process.

1. Allocate PV forecasts to the distribution circuits.
2. Model the impact of forecasted PV on the distribution system.
3. Identify solution options to integrate the forecasted PV.
4. Quantify the integration plans and costs for all solutions.
5. Derive integration cost estimates.

We describe each step in the methodology below.

Step 1: Allocate PV Forecasts to the Distribution Circuits

The DG-PV forecasts reflect the system-wide forecasted growth of DG-PV on each island grid for the two DG-PV scenarios. To determine the cost to integrate these total DG-PV levels, we analyzed the impact to each individual circuit. The installation of DG-PV is a customer choice; thus, we cannot predict the exact installation location of future DG-PV at the circuit level. This analysis assumed PV would grow proportional to current circuit penetration levels, with the rationale that the PV industry has identified and penetrated those market segments, neighborhoods and circuits with the resources and market drivers to adopt PV.

We increased each circuit's existing PV level year over year by the growth rate determined by the PSIP April 2016 market and high DG-PV forecasts. PV grew on each circuit constrained by its maximum potential, which was determined by estimating the number of single-family homes residing on each circuit. A customer's historical 12-month energy consumption dictated the size of future PV systems. The maximum potential also considered the commercial sector by estimating that 25% of commercial customers on a circuit installed PV. Where Hawai‘i Electric Light and Maui Electric did not have detailed demographic data of a circuit, customer counts and rate class information were used as a proxy to estimate the maximum PV potential of the circuit.

A circuit did not receive additional growth after the year in which it reached its maximum PV potential. Circuits that currently have low penetration did not reach its maximum potential, as it is indicative of neighborhoods with sub-optimal solar conditions or neighborhoods with low market drivers. Many currently saturated circuits reached their maximum potential well before 2045.

Figure N-10 through Figure N-12 compare the updated forecast with the forecast used for the integration costs as determined for the April 2016 PSIP update.

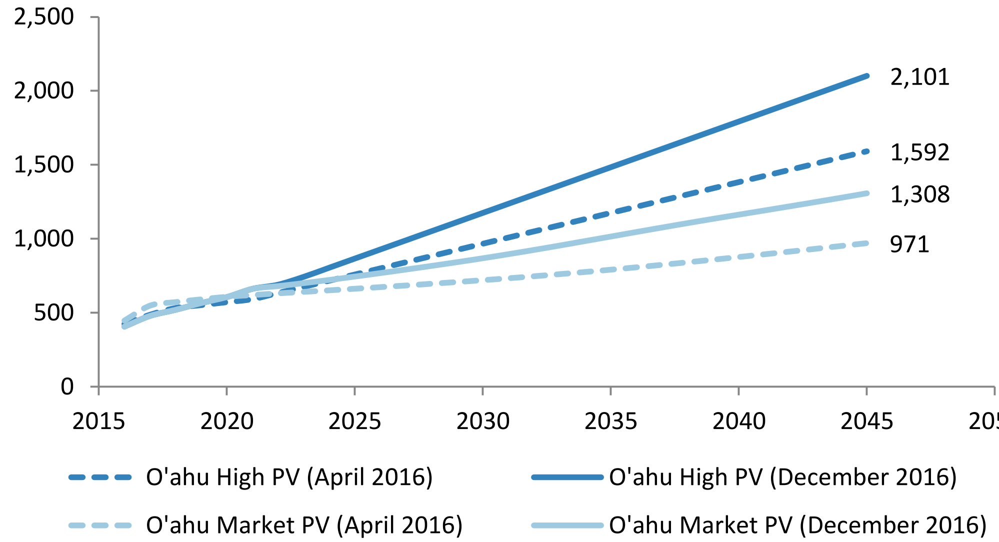

Figure N-10. Oʻahu Market and High DG-PV Forecast

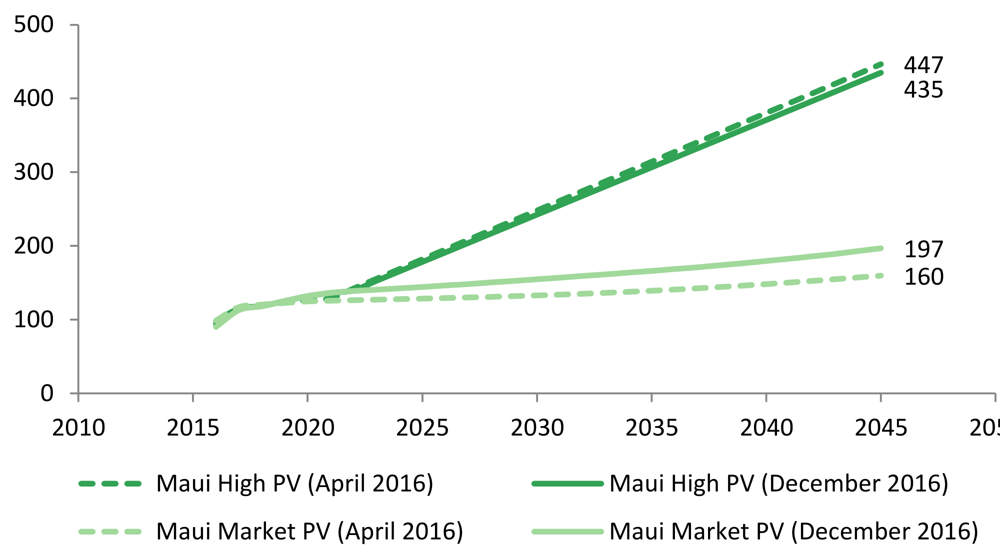

Figure N-11. Maui Market and High DG-PV Forecast

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

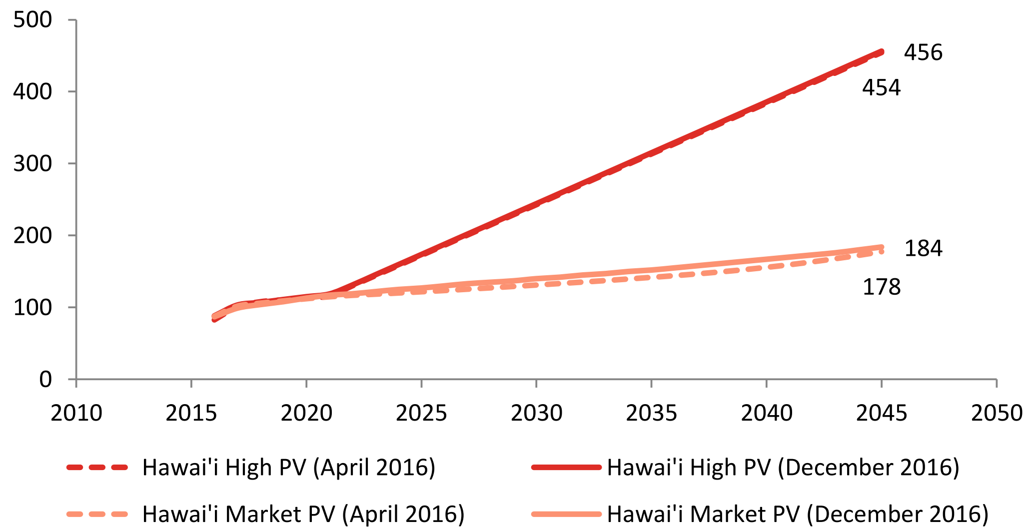

Figure N-12. Hawai'i Island Market and High DG-PV Forecast

The December 2016 forecasts compared to April 2016 shows a marginal difference in the Hawai'i Island and Maui high DG-PV forecast. The Maui market forecast increased by 23%. However, the O'ahu forecasts increased by 32% and 35% in the high DG-PV and market DG-PV forecast, respectively. In all cases, the 5-year forecast remains relatively unchanged.

The revised forecasts also provide a storage component as part of the customer self-supply program. We expect the additional storage component to help offset any additional PV impacts resulting from the increased revised PV forecasts. For these reasons, the DG-PV integration costs discussed here remain unchanged over the April 2016 update as it serves as a reasonable proxy.

The section "DG-PV Forecasts by Distribution Circuit" (page N-63) details the DG-PV adoption by circuit.

Step 2: Model the Impact of Forecasted PV on the Distribution System

Any circuit forecasted to exceed its hosting capacity or operational circuit limit[5] was analyzed to determine the cost to integrate the forecasted PV amount. Circuits not forecasted to exceed its hosting capacity did not incur major circuit upgrades; therefore, an integration cost was not determined. Table N-6 and Table N-7 tabulate the number of circuits, for each operating company, that are forecasted to exceed their hosting capacity and operational circuit limit in the market DG-PV case and high DG-PV case.

[5] The hosting capacity is the level of PV that a circuit may host without requiring upgrades to the primary part of the distribution system. The operational circuit limit defines the reverse power threshold at the substation to maintain the operational flexibility of the circuit.

Market DG PV Case	Total Distribution Circuits	Exceeded Hosting Capacity Only	Exceeded Operational Circuit Limit
Hawaiian Electric	416	64	86
Maui Electric	137	44	7
Hawai'i Electric Light	135	49	22

Table N-6. Circuits Forecasted to Exceed Hosting Capacity and Operational Circuit Limit (Market DG-PV)

High DG-PV Case	Total Distribution Circuits	Exceeded Hosting Capacity Only	Exceeded Operational Circuit Limit
Hawaiian Electric	416	41	160
Maui Electric	137	76	76
Hawai'i Electric Light	135	20	94

Table N-7. Circuits Forecasted to Exceed Hosting Capacity and Operational Circuit Limit (High DG-PV)

The analysis assessed three areas in determining integration costs: thermal capacity, voltage power quality, and operational flexibility. The analysis used the hosting capacity models[6] to grow each circuit to its forecasted PV amount. We flagged any conductor that exceeded 100% of its thermal rating from the reverse power flow of PV for mitigation.

Analyzing voltage power quality requires a deeper analysis of the hosting capacity models, and analysis results vary by location. Mitigation of unacceptable voltage levels normally requires multiple iterations of load flow simulations. Consequently, we analyzed a cross section of representative circuits with their forecasted PV growth amounts, and applied the results to all distribution circuits. We flagged areas where PV caused voltage to rise more than 2.5% of nominal on the primary for mitigation. ANSI Standard C84.1, Range A, requires delivery of voltage to customers at ±5% of nominal voltage. Our typical design of the distribution system allows for 2.5% voltage drop or rise between the substation and the distribution transformer (primary side) and 2.5% voltage drop or rise between the distribution transformer and the customer meter, totaling to the delivery of voltage within ±5% of nominal voltage.

Maintaining the flexibility of the distribution system is vital to the reliability and safety of electrical service to our customers. If the forecasted reverse power flow from PV of a circuit exceeds that circuit's operational circuit limit then that circuit was flagged for mitigation.

[6] See *Rooftop PV Interconnections: A Methodology of Determining PV Circuit Hosting Capacity* filed in Docket No. 2014-0192, on December 11, 2015.

Step 3: Identify Solution Options to Integrate the Forecasted PV

The identification of solutions to resolve thermal capacity, voltage power quality, and operational flexibility issues are categorized as traditional "wires" solutions and technology "non-wires" solutions. While many different solutions exist, Table N-8 describes the various solution options considered in this analysis. The cost-effective option served as an input to DG-PV adoption model.

Solution Portfolio		
Issue	*Traditional (Wires)*	*Technology (Non-Wires)*
Thermal Capacity	■ Overhead and Underground Conductor Upgrade ■ Distribution Transformer Upgrade	■ Battery Energy Storage
Voltage Quality	■ Voltage Regulator Installation ■ Distribution Transformer and Secondary Conductor Upgrades	■ Var Compensation Devices ■ Advanced Inverters
Operational Flexibility	■ Reconfigure Circuit ■ New Circuit and/or Substation Transformer	■ Battery Energy Storage ■ Advanced Inverter DER Controllability

Table N-8. Portfolio of Solutions to Integrate Forecasted DG-PV Amounts

It is important to draw a distinction between mitigation and optimization solutions. The analysis completed here are necessary upgrades. Failure to implement these solutions would compromise distribution system safety and reliability, including its effect on non-participating customers. Technology solutions in particular, will restore the integrity of the system to normal operating conditions and generally do not provide circuit optimization or improved efficiencies.

The following describe in detail each of the solutions in the portfolio.

Overhead and Underground Conductor Upgrade. Excess rooftop PV energy will create reverse power flow that may load conductors past 100% of their thermal rating. To create additional rated capacity, conductors are upgraded to a larger size. Load flow simulations of the hosting capacity models with PV grown to the forecasted PV amounts determined the total length of overloaded conductors in the market and high DG-PV cases. The total length of overloaded conductors by circuit were scheduled for upgrade between the year the PV forecast per circuit exceeded the hosting capacity and ending in the final year of PV growth. The cost to upgrade overhead conductors including wood pole construction is estimated at $1,100,000 per mile in 2016 dollars. The cost to upgrade underground conductors including duct bank and manhole installation is estimated at $4,300,000 per mile in 2016 dollars.

Voltage Regulator Installation. A voltage regulator is a traditional solution that corrects voltage power quality issues, and is installed on circuits that exceeded its hosting capacity. High and low voltage will be the number one barrier to interconnection in the near-term.

Load flow simulations of representative circuits demonstrated that neighborhoods or sections of circuits might experience high and/or low voltage. Each circuit is unique and will vary in its voltage quality issues. Based on the representative analysis, we made the assumption that up to three voltage regulators per circuit would be required to correct voltage impacts. Each circuit that exceeded its PV hosting capacity incurred a voltage regulator installation for three consecutive years following the year in which it exceeded its hosting capacity, except in the case where PV growth stopped in less than three years. The cost to install a single-phase regulator and three-phase regulator is estimated at $25,000 and $75,000 respectively, and does not include potential wood pole replacement. For the purposes of this analysis, the unitized cost per voltage regulator installation was estimated at $41,667 in 2016 dollars; the average cost of installing two single-phase regulators and one three-phase regulator.

Distribution (Service or Secondary) Transformer Replacement. Distribution transformers are upgraded, if the ratio of aggregate PV connected to a transformer to the transformer rating exceeds 200%.[7] In other cases, secondary high voltage will necessitate an upgrade of secondary conductors in addition to the replacement of the distribution transformer.[8] The load flow simulations of the hosting capacity models determined that in the market DG-PV case, 16% of distribution transformers would have a PV penetration (the ratio of aggregate PV connected to a single transformer to the transformer rating) in excess of 200%, and 26% in the high DG-PV case. We applied these results to predict the amount of future transformer upgrades required to resolve both loading and voltage issues, which can be mutually exclusive. The average cost for this upgrade is estimated at $13,500, representing the estimated average cost between a transformer upgrade to address overloading and an upgrade to address secondary high voltage. In practice, correction of secondary high voltage may cost more than $13,500, particularly if underground construction is required; however, for this analysis all service transformer work was assumed to cost $13,500 in 2016 dollars.

Reconfigure Circuits. The most cost-effective method to resolve the loss of operational flexibility is to reconfigure a circuit. Before requiring any type of substation upgrades, planners will analyze the circuits to determine whether a circuit is capable of reconfiguration with an intertied circuit. We did not perform this analysis in the

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[7] The Companies worked with their distribution transformer manufacturer to determine the appropriate PV penetration level as to not severely impact the life and performance of the transformer. Based upon the results of the manufacturer analysis, it was determined that we would allow 200% PV penetration on a distribution transformer before taking remedial action.

[8] Distribution transformer upgrades can be triggered well in advanced of a circuit reaching hosting capacity. Issues related to distribution transformer upgrades were not considered in establishing a circuit's hosting capacity. Whether a distribution transformer upgrade is required is dependent on a set of localized factors.

development of the integration costs except for a few cases; the vast majority of operational circuit limit exceedances were resolved with substation upgrades. As circuits approach these limits in future years, we will always seek to avoid substation upgrades where possible. No capital costs were assigned for this work.

Substation Upgrades. Substation upgrades are triggered in two ways: (1) if operational flexibility is lost where reverse power loads the substation transformer more than 50% of its highest transformer rating, or (2) with controllable PV, reverse power flow loads the substation transformer more than 100% of its highest transformer rating. Current operational practice maintains operational flexibility during normal operation, and therefore reverse power flow is roughly limited to 50% of the substation transformer's highest rating. However if PV is controllable through the use of advanced inverters, it is possible to allow reverse power flow to load the transformer up to 100% of its thermal rating during normal operation, and regulate the PV power output during abnormal conditions.

There are a number of factors to consider in determining the cost of a substation upgrade. The scope of the upgrade could include building a new substation on new land, installing a new substation transformer and circuit(s) in an existing substation, installing a new circuit at an existing substation transformer, or converting a 4kV substation to 12kV.[9] Broad assumptions were made for this analysis; in practice, detailed engineering will determine the scope of the upgrade.

The base assumption for a substation upgrade is $10,000,000, which includes two (46kV) terminations, two substation transformers, two 12kV switchgears, four 12kV feeders, one acre of land, and communication infrastructure. We unitized the cost on a per feeder basis with considerations of various factors. For example, if a substation transformer exceeded the 50% limit, the two circuits it serves require a substation upgrade. If the existing substation has space for an additional substation transformer, land costs were subtracted from the base $10,000,000 and divided by four feeders to arrive at the per feeder cost. In this example, the per feeder cost is $2,000,000. The range of costs used for a substation upgrade varies between $1,000,000 and $5,000,000 per feeder in 2016 dollars. Each circuit was analyzed at a high level (without detailed engineering) to determine the most appropriate cost of the upgrade.

Battery Energy Storage Systems. Deploying distributed battery energy storage systems behind or in front of the meter can relieve distribution system congestion and maintain

[9] If 4kV substation transformers or circuits require an upgrade, we will convert that area to a higher primary voltage, instead of installing additional 4 kV substations. This is part of an overall strategy to convert 4kV areas to higher primary voltages. These costs were not included in the DGIP based upon the assumption that 4kV circuits would eventually be converted. However in this analysis these costs are included because the 4 kV conversion projects would not coincide with PV growth. This adds significant cost over what was reported in the DGIP. 4kV conversions are higher in cost than new substation installations ($5M vs $2M–$3M on a per feeder basis) because of the labor hours required to retrofit a circuit with higher primary voltage wires and transformers.

operational flexibility. Strategically located storage can avoid conductor overloads, while simultaneously maintaining operational flexibility. Battery cost assumptions are provided in the resource cost forecast in Figure N-13.

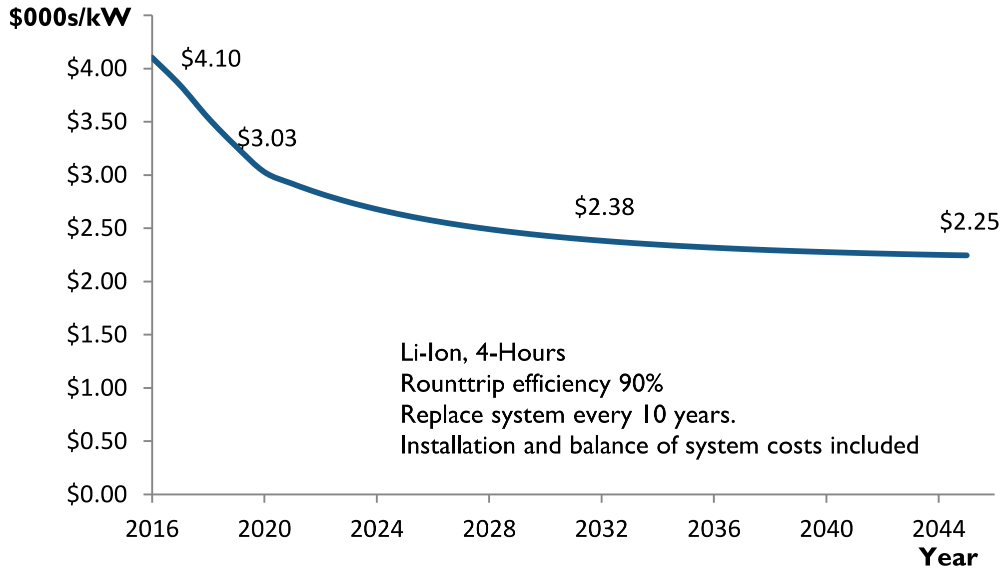

Figure N-13. BESS Cost Assumptions

Battery energy storage systems need to be accountable when deployed to relieve capacity and operational flexibility issues. One important design characteristic for this type of battery energy storage system is to ensure each morning the battery capacity is available to store that day's excess energy; otherwise, the excess energy will cause an overload. For this analysis, we assumed a four-hour charge and discharge cycle battery.

While battery energy storage systems may avoid the installation of a new substation, circuit or conductor upgrade, the current state of the technology estimate a 10-year lifecycle. Replacement storage quantities and costs were included in the integration cost estimates 10 years from the original deployment of a battery energy storage system. It should be noted that conductor upgrades and substation upgrades have lifecycles in excess of 20 years; therefore, not assumed to require replacement. In addition, battery energy storage system failure must be accounted for. Rather than building redundant storage, the cost effective option is a combination of energy storage and circuit-level control of advanced inverter powered DG-PV. If a battery fails and compromises the safety and reliability of the system, DER control mechanisms should activate to regulate the active power output, particular if multiple failures occur simultaneously.

Var Compensation Devices. Var compensation devices leverage modern power electronics to provide fast acting reactive power to reduce voltage fluctuations, and regulate circuit voltages to avoid the high voltage effects of deep penetrations of DG-PV. These devices come in many different forms: low voltage static compensators, fast switching capacitors, inline power regulators, and advanced inverters. These types of devices, located on the secondary part of the distribution system, can potentially provide more cost-effective and efficient regulation to mitigate voltage quality impacts and displace traditional, slower acting equipment such as capacitor banks and voltage regulators. This distributed voltage regulation technique represents a departure from traditional industry methods of voltage regulation. While we have started to demonstrate and assess these innovative devices, the technology is a relatively recent development and has yet to achieve widespread adoption across the industry. We will determine the viability and deployment of these devices once we complete our assessment of these devices from a planning and operating perspective.

To quantify the cost of these devices, representative circuits were modeled to determine the quantity of existing inverters that are required to have reactive power capabilities to mitigate existing high voltages. It was determined that for O‘ahu and Maui 12% of the existing inverter fleet would require retrofit. However, a smart inverter retrofit is not the sole method to resolve high voltage issues given the implementation challenges with customer ownership of the PV inverters. Therefore, the analysis assumed a non-specific solution that includes all device strategies discussed above. An estimated cost to install power electronic devices that provide reactive power compensation was based on a unitized cost estimated at $855 per kilowatt in 2016 dollars. This cost was derived from an NREL report discussing PV costs for residential, commercial and utility-scale systems[10] in Hawai‘i.

Advanced Inverter DER Controls Infrastructure. Distribution system management will require controllability of customer DER assets by the system operator to maintain safe, efficient, reliable operations. Advanced inverters will play a pivotal role to enable controllability, which we now require as part of our most recent revisions to interconnection Rule 14H. The cost to implement DER controls include foundational infrastructure such as: advanced distribution management system, a distributed energy resource management system (DERMS), advanced metering infrastructure (AMI); however, for the purposes of the integration cost estimates, only infrastructure required to directly implement controls on a DER asset are considered. Controllability costs are not incurred until 2018, at which time it is assumed that the DERMS and AMI projects are installed and capable of initiating basic controls of DER assets. The cost of the DERMS and AMI projects were not included in this study’s integration costs. It is assumed that every new DER system will be outfitted with the necessary hardware and software to enable controllability; this cost is estimated at $1,500 per system. Assuming

[10] See Chung, Davidson, et al (September 2015): *U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential Commercial and Utility-Scale Systems*, Golden, Colorado: National Renewable Energy Laboratory, TP-6A20-64746 at 7–9. This report states the cost to install a 5.2kW PV system in Hawai‘i is $3,280 per kW in 2015$. The $855 per kW unitized cost was derived by subtracting the supply chain, balance of system, PV module and racking, customer acquisition, overheads, and profit costs from the $3,280 estimate.

an average PV system size of 6 kW, the number of total PV systems installed each year was determined. This $1,500 per DER system cost estimate is a high-level estimation of the cost of communication hardware (such as, communication gateway) and any associated firmware costs.

Communication standards are under development within the utility and solar industry.[11] We assumed for this study availability of these capabilities in 2018.

Step 4: Quantify the Integration Plans and Costs for All Solutions

Upon completion of the circuit specific analysis, the portfolio of integration solutions were each quantified into various strategies. This section describes the different strategies (and associated costs) that we considered to integrate PV in the market and high DG-PV cases. The strategies fell into two general categories—traditional or wires solutions and technology or non-wire solutions—that were then used to create three DER integration strategies in the market case and four DER integration strategies in the high DG-PV case.

- Strategy 1: Traditional or wires solutions to integrate the market DG-PV case.
- Strategy 2: Technology or non-wires solutions to integrate the market DG-PV case.
- Strategy 3: No storage solution with advanced inverter controls to integrate the market DG-PV case.
- Strategy 4: Traditional or wires solutions to integrate the high DG-PV case.
- Strategy 5: Traditional or wires solutions with advanced inverter controls to integrate the high DG-PV case.
- Strategy 6: Technology or non-wires solutions to integrate the high DG-PV case.
- Strategy 7: Least storage solution with advanced inverter controls to integrate the high DG-PV case.

Strategy 1 and 4: Traditional or Wires Solutions

Traditional or wires solutions solve thermal equipment overloads, degraded voltage quality, or loss of operational flexibility by upgrading or installing conductors, transformers, or voltage regulators. In these two strategies, operational flexibility is maintained by creating a new substation and/or circuits when the reverse power flow from excess PV generation exceeds 50% of the transformer rating.

Traditional upgrades are proven, tested solutions with an asset life of 20+ years compared to less traditional solutions such as energy storage, which may require

[11] The California Smart Inverter Working Group recently filed DER communication recommendations with its Public Utilities Commission; a decision is still pending. Arizona Public Service and Tucson Electric Power are currently running rooftop solar programs testing smart inverter capabilities, including inverter communications, http://www.solarelectricpower.org/utility-solar-blog/2015/january/arizonas-utility-owned-solar-programs-new-price-models,-grid-integration-and-collaboration.aspx.

replacement in 10 years. Depending on the scope, traditional solutions may have significantly longer installation times.

Figure N-14 through Figure N-19 summarize by island, the cost to integrate PV under Strategy 1: traditional solutions in the market DG-PV case, and Strategy 4: traditional solutions in the high DG-PV case.

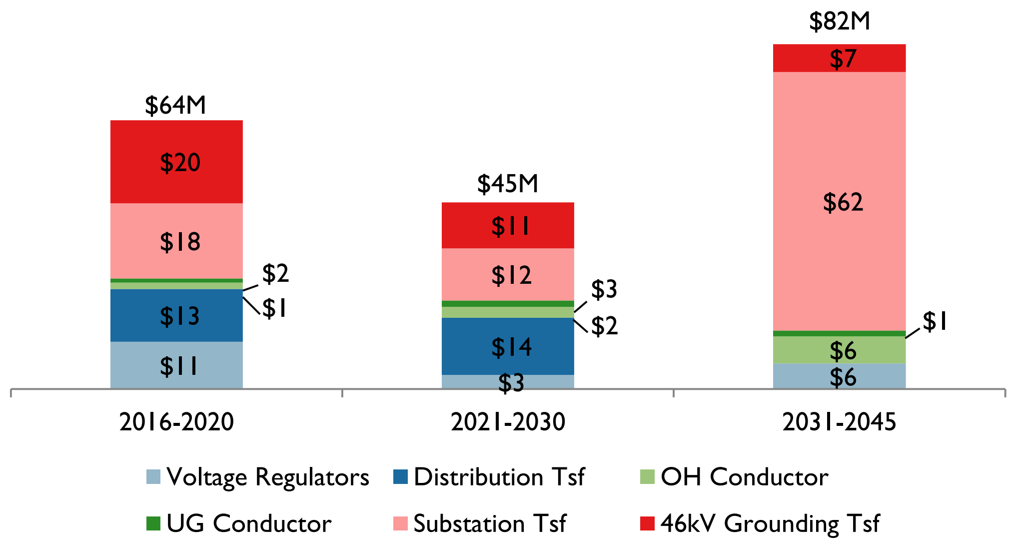

Figure N-14. Strategy 1 Annualized Integration Costs: O'ahu (Nominal $M)

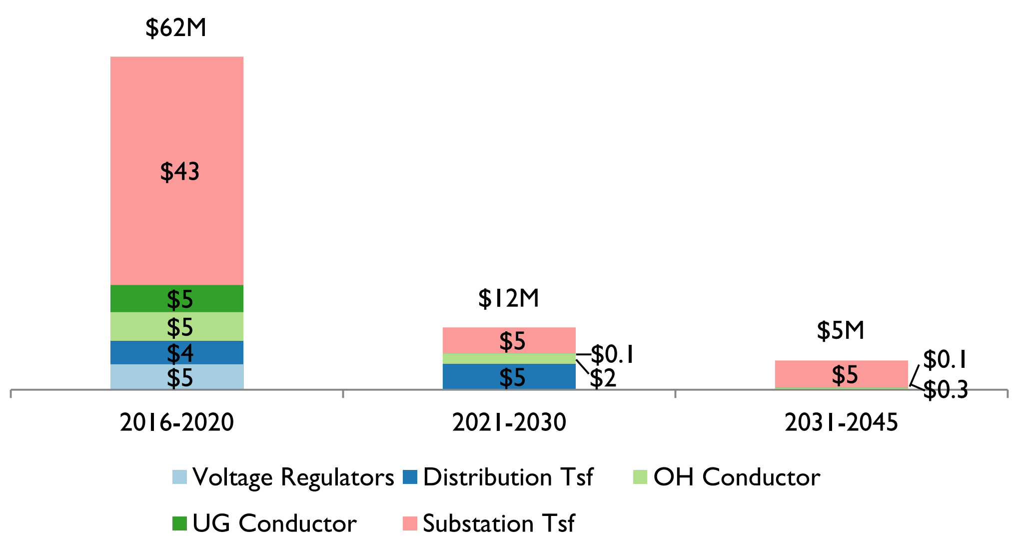

Figure N-15. Strategy 1 Annualized Integration Costs: Maui (Nominal $M)

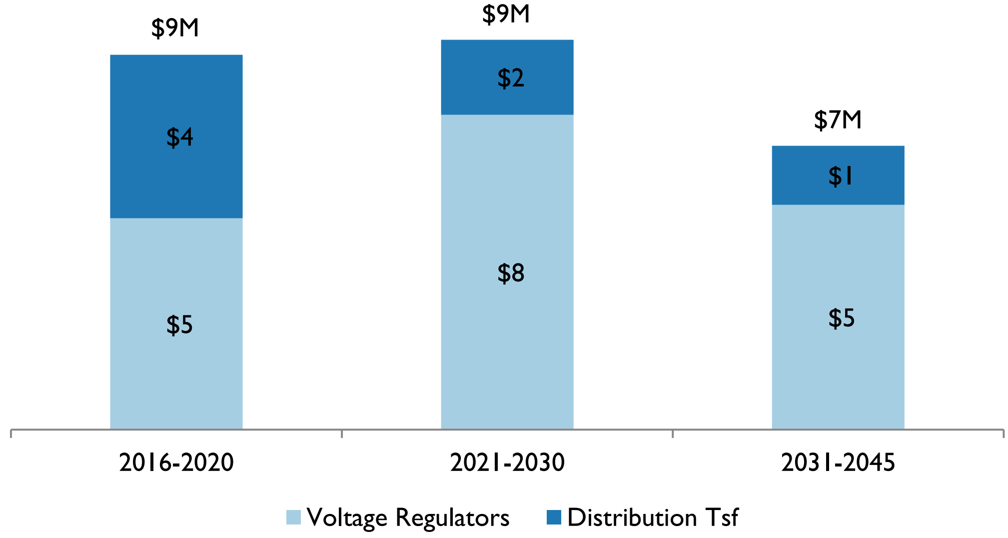

Figure N-16. Strategy 1 Annualized Integration Costs: Hawai'i Island (Nominal $M)

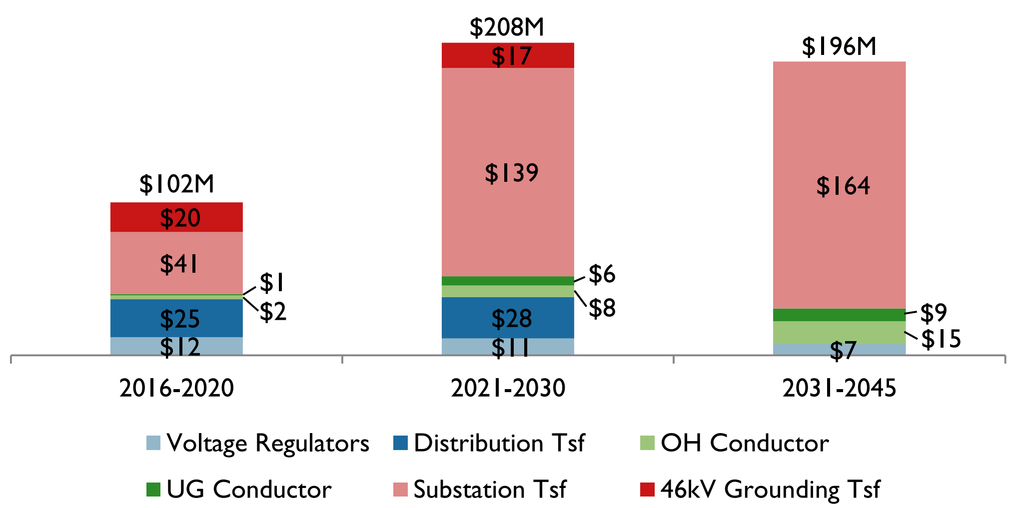

Figure N-17. Strategy 4 Annualized Integration Costs: O'ahu (Nominal $M)

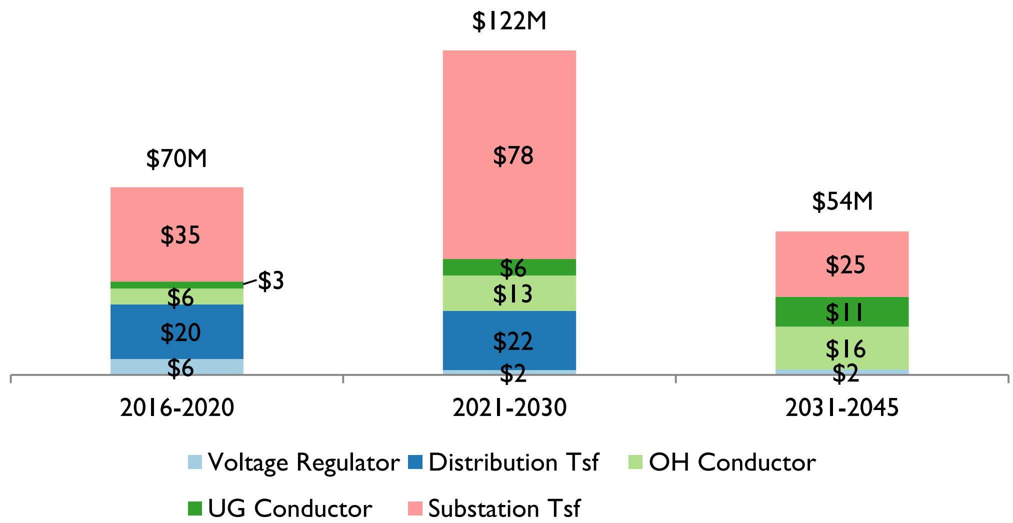

Figure N-18. Strategy 4 Annualized Integration Costs: Maui (Nominal $M)

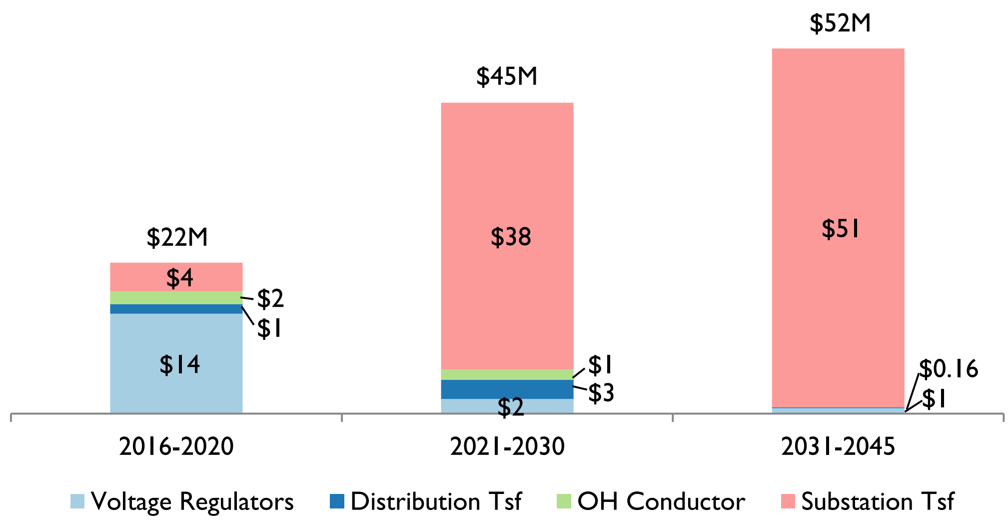

Figure N-19. Strategy 4 Annualized Integration Costs: Hawai‘i Island (Nominal $M)

Strategy 5: Traditional or Wires Solutions with DER Controls

This strategy applies solely in the high DG-PV case because the PV penetration in the market case does not cause any substation transformer to exceed 50% of its thermal rating. In this strategy, the reverse power from PV is operationally allowed to exceed the 50% criterion but not exceed 100% of the substation transformer's thermal rating. In the high DG-PV case, any reverse power flow that exceeds 100% of the transformer's thermal rating triggers a substation upgrade; this criterion significantly reduces number of substation upgrades compared to Strategy 4. To protect the distribution system from the loss of operational flexibility, controllability of advanced inverters is required for PV systems that cause a violation of the operational circuit limit. Conceptually this requirement is similar to that of grid-scale resources under direct control or the system operator,[12] for emergency or abnormal conditions. The capability for the system operator to control these rooftop PV systems, aggregated by circuit, is essential to maintaining the operational flexibility and by extension, the safety and reliability of the distribution system.

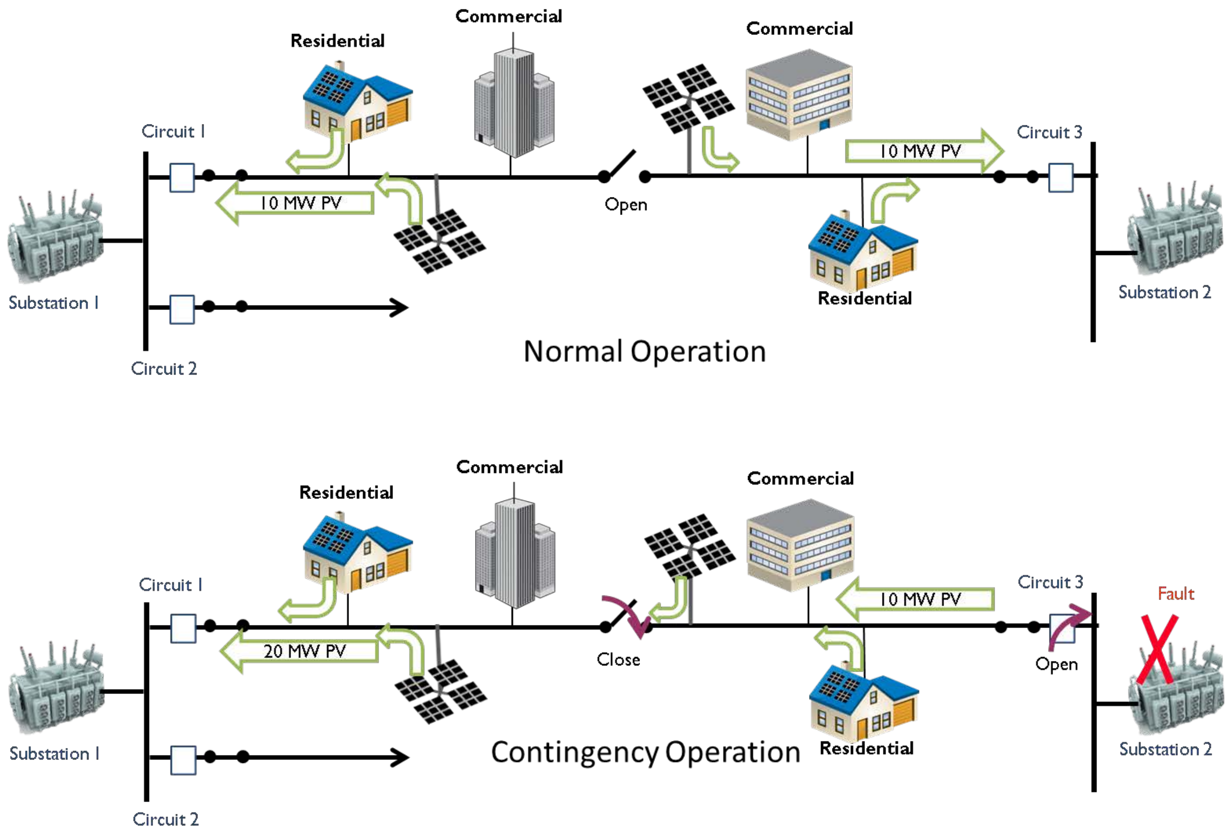

Figure N-20. Overloaded Substation During a Contingency Event (Example)

As Figure N-20 illustrates, if neighboring substations were both loaded with reverse power flow equal to 100% of their rated capacity (10 MW), and one of these substations required servicing or suffered an unplanned outage, the neighboring substation would need to provide reliable electric service to the circuit that is out of service. The out of service circuit would then be transferred to the neighboring substation transformer that remains in service to restore electric service to those customers experiencing an outage. Before doing so, the system operator would turn off the PV systems on the out of service circuit before restoring service to prevent those PV systems from turning on when service

[12] Per Rule 14 paragraph H, supervisory control is mandatory for generating facilities with an aggregate capacity greater than 1MW to ensure prompt response to system abnormalities, and may be required for facilities between 250 KW and 1 MW. At Maui Electric and Hawai'i Electric Light, supervisory control is mandatory for facilities 250kW and greater. See HECO, MECO, HELCO Rule 14.

is restored. Failing to turn off the PV systems of the customers undergoing a transfer to the neighboring circuit may then cause an overload of 200% (20 MW) to the in-service substation transformer—the combination of the PV systems on the existing in-service circuits and the PV systems that were transferred from the now out-of-service circuits.

Figure N-21 through Figure N-23 summarize by island, the cost to integrate PV under Strategy 5: traditional solutions with DER controllability in the high DG-PV case.

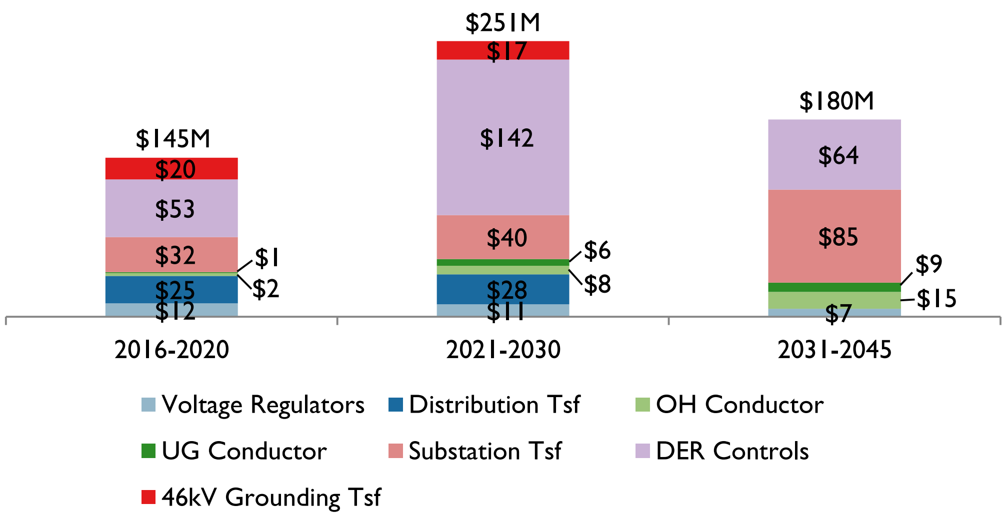

Figure N-21. Strategy 5 Annualized Integration Costs: O'ahu (Nominal $M)

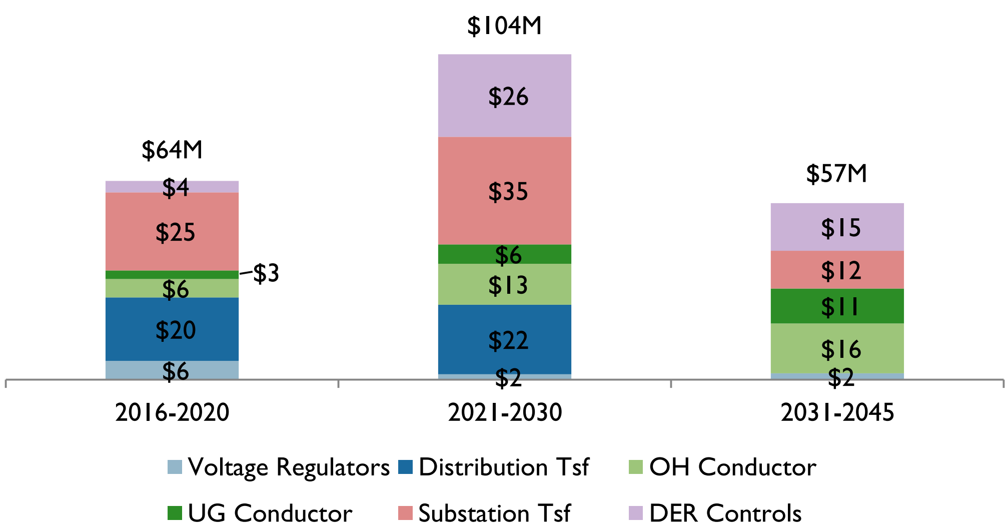

Figure N-22. Strategy 5 Annualized Integration Costs: Maui (Nominal $M)

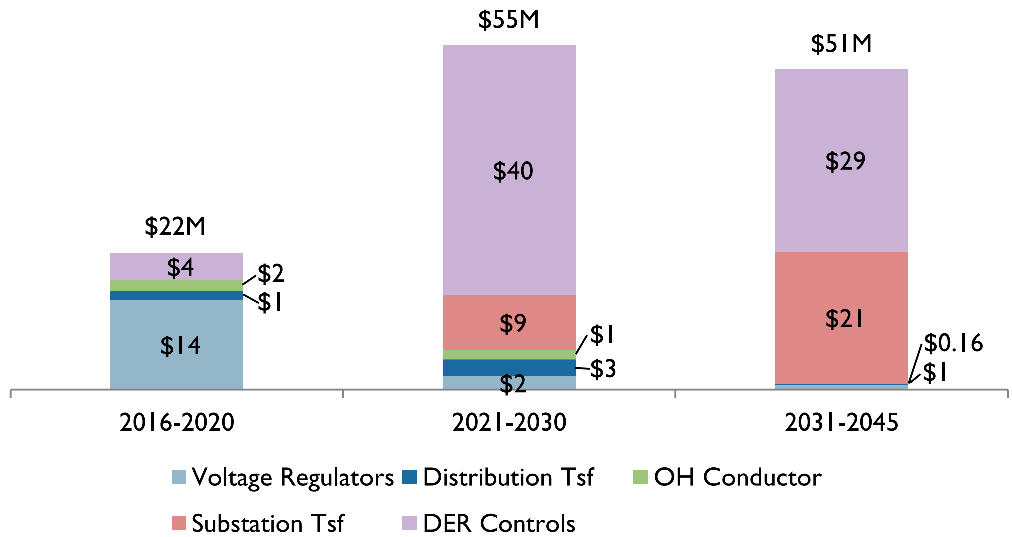

Figure N-23. Strategy 5 Annualized Integration Costs: Hawai'i Island (Nominal $M)

Strategy 2 and 6: Technology or Non-Wires Solutions

Technology or non-wires solutions leverage new technologies and distributed energy resources to resolve PV impacts. We utilize energy storage to store energy in excess of the operational circuit limit; thereby restoring lost operational flexibility and avoiding the installation of new circuits or substations, as indicated in Strategies 1 and 4. We also assumed that storage is strategically located on the distribution system to simultaneously alleviate overloaded conductors and service transformers.

Failure of an energy storage system that was previously relied upon to mitigate an overload, would pose a risk to the integrity of the distribution system equipment. To plan for this contingency, PV facilities should be controllable through advanced inverters by the system operators in the event that an energy storage device fails. If centralized control is unavailable, local energy management systems may autonomously manage the local energy while receiving signals from the utility during contingency operations to avoid unsafe operating conditions.

This strategy of utilizing battery energy storage systems is cost prohibitive compared to Strategies 3 and 7; however, storage may provide other ancillary benefits—such as energy shifting and frequency regulation. Battery storage would also reduce sub-transmission congestion by reducing the amount of energy exported to the sub-transmission and transmission system.

Lastly, in this strategy, var compensation devices will mitigate voltage power quality impacts. While these technologies have yet to reach widespread adoption, this distributed voltage regulation philosophy and devices may represent the future of voltage regulation and improved distribution system efficiencies.

Figure N-24 through Figure N-29 summarize by island, the cost to integrate PV under Strategy 2: technology solutions in the market DG-PV case, and Strategy 4: technology solutions in the high DG-PV case.

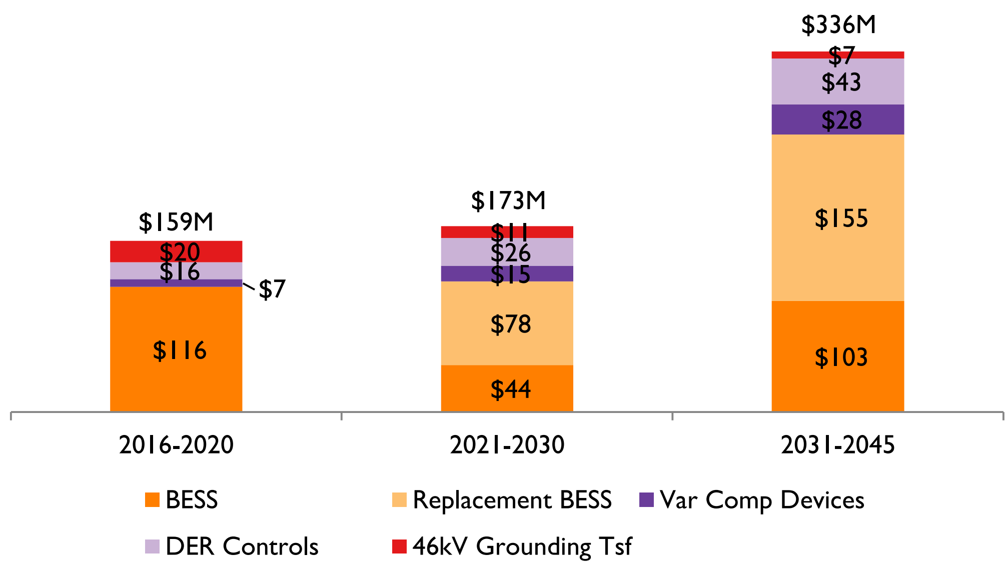

Figure N-24. Strategy 2 Annualized Integration Costs: O'ahu (Nominal $M)

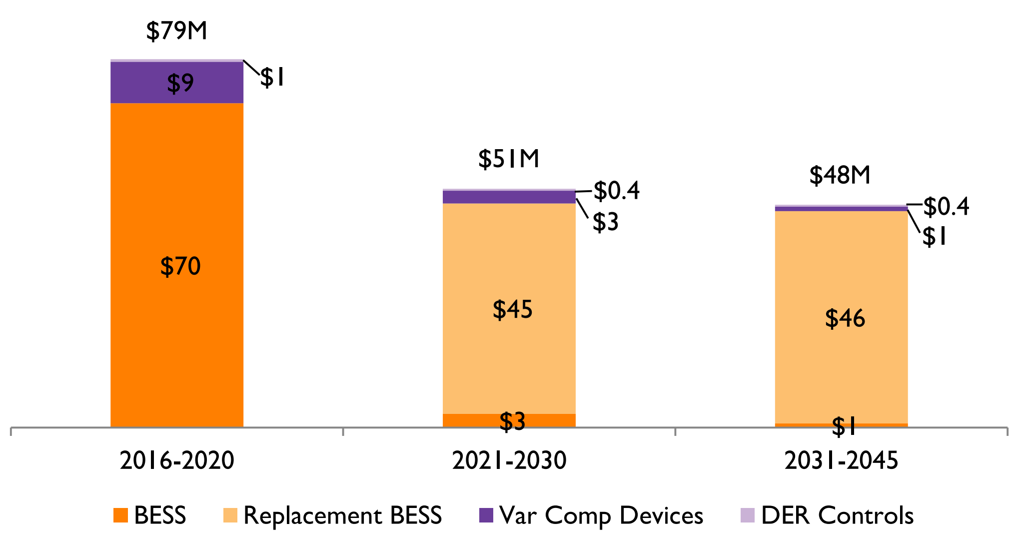

Figure N-25. Strategy 2 Annualized Integration Costs: Maui (Nominal $M)

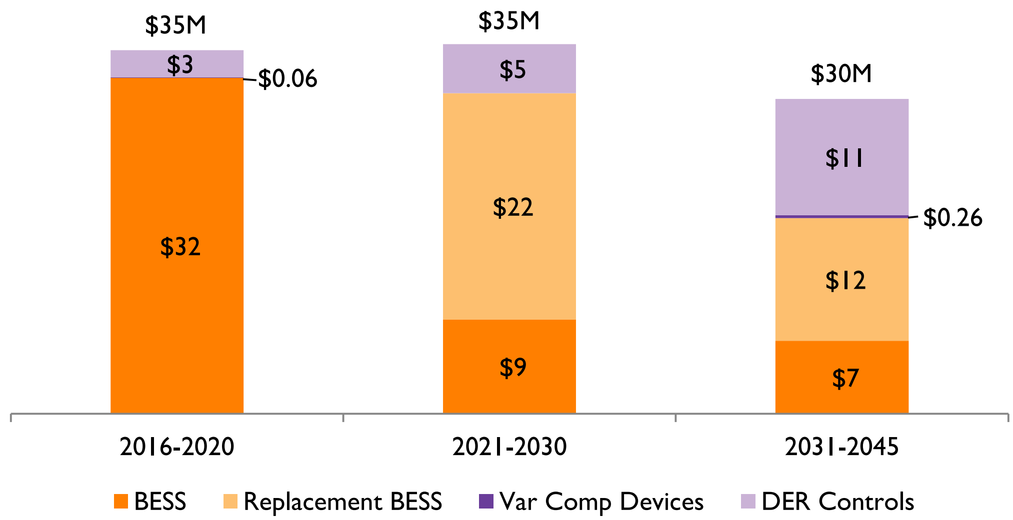

Figure N-26. Strategy 2 Annualized Integration Costs: Hawai'i Island (Nominal $M)

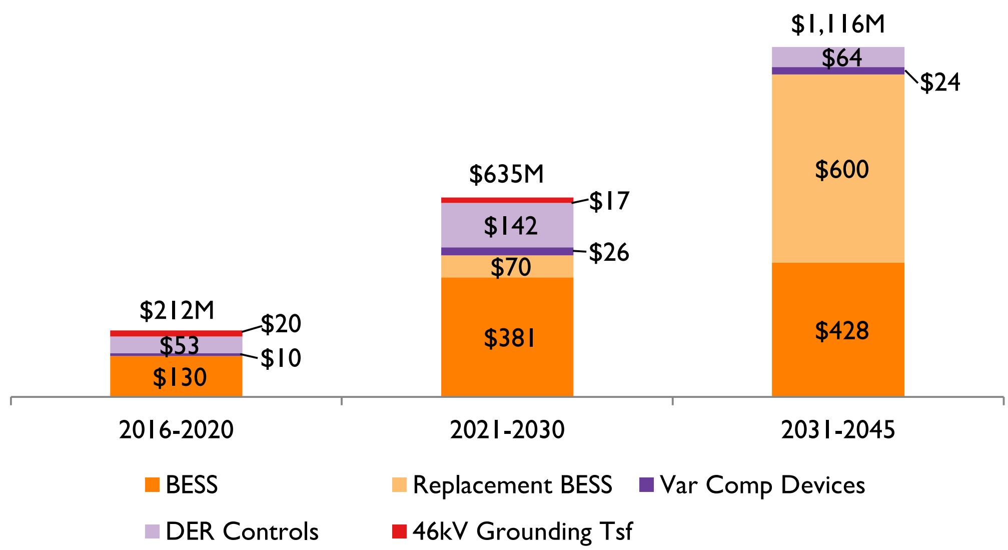

Figure N-27. Strategy 6 Annualized Integration Costs: O'ahu (Nominal $M)

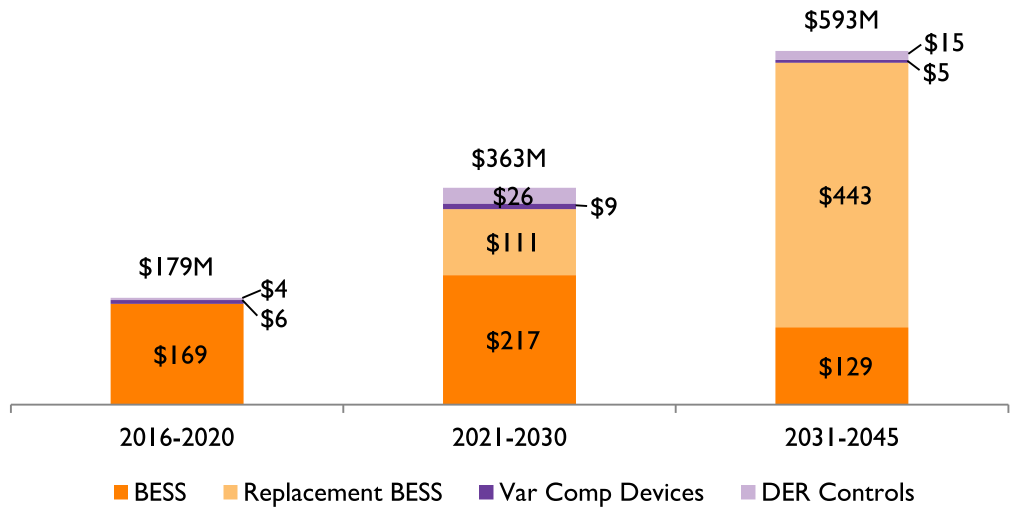

Figure N-28. Strategy 6 Annualized Integration Costs: Maui (Nominal $M)

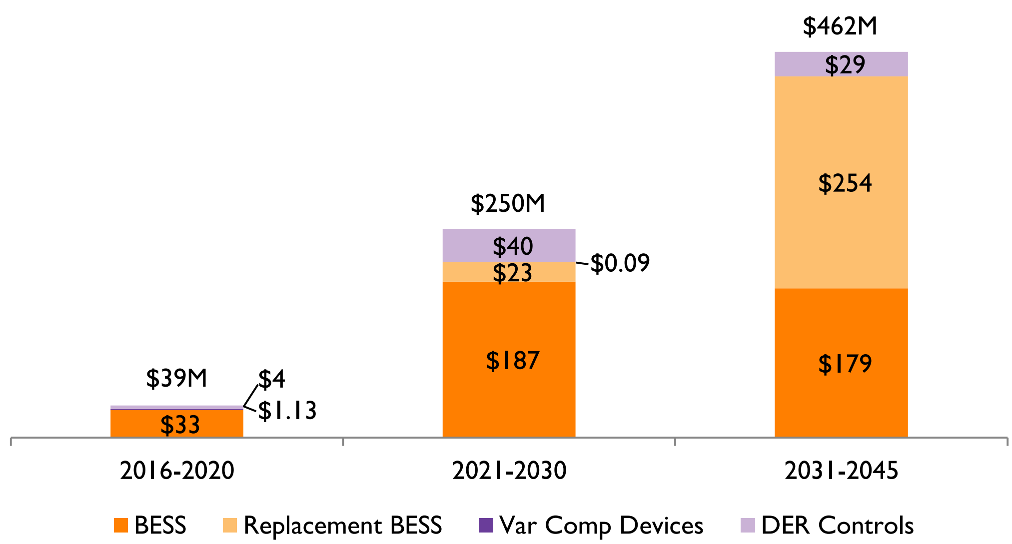

Figure N-29. Strategy 6 Annualized Integration Costs: Hawai'i Island (Nominal $M)

Strategy 3 and 7: Least Storage Solution with Advanced Inverter Controls

This strategy is a variation of the technology solutions described in Strategy 2 and Strategy 6, with the exception that operational flexibility is not maintained during normal conditions, similar to Strategy 5. In this strategy, the analysis demonstrates that storage is not required in the market DG-PV case and minimal storage in the high DG-PV case; however direct control of the PV facilities through the use of advanced inverter controls is required to allow the system operator to restore the operational flexibility when needed (that is, outage event). Sub-transmission congestion is increased under this strategy but manageable with advanced inverter controls.

There is the potential for increased curtailment of distributed resources in these strategies but we are unable to quantify those amounts at this time, as it is highly dependent on the location of the DER assets.

Potential conductor upgrades are still required to avoid overloads, which is relatively low cost compared to storage as an alternative. Future energy management system technology is assumed to manage service transformer overloads. This measure of control can avoid service transformer replacements, and is reflected in the cost estimate of these strategies.

In the first 2 to 3 years of this strategy, voltage regulators and substation transformers are required at which time those solutions are phased out and replaced with advanced inverter controllability and var compensation devices.

Figure N-30 through Figure N-35 summarize by island, the cost to integrate PV under Strategy 3 and Strategy 7: least storage solution with advanced inverter controls.

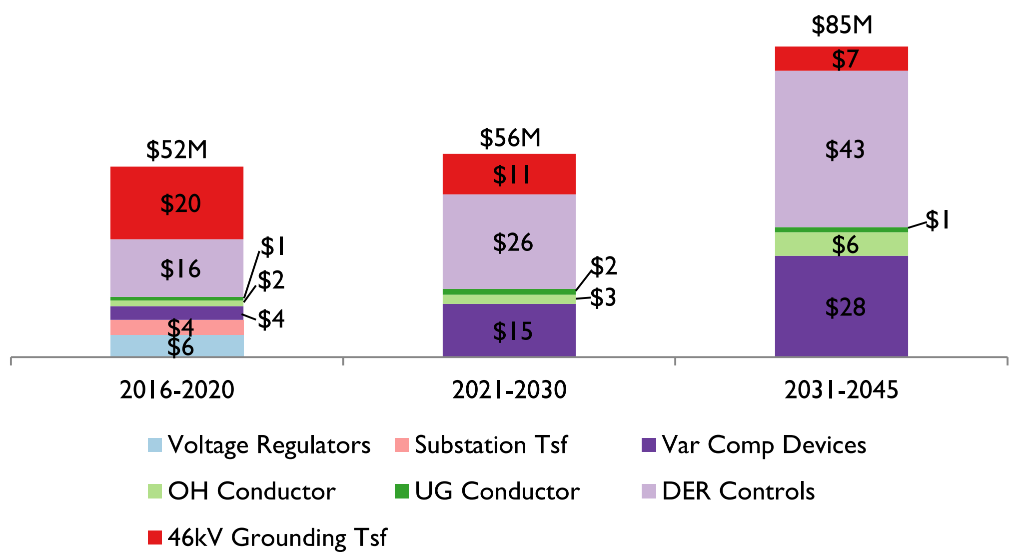

Figure N-30. Strategy 3 Annualized Integration Costs: O‘ahu (Nominal $M)

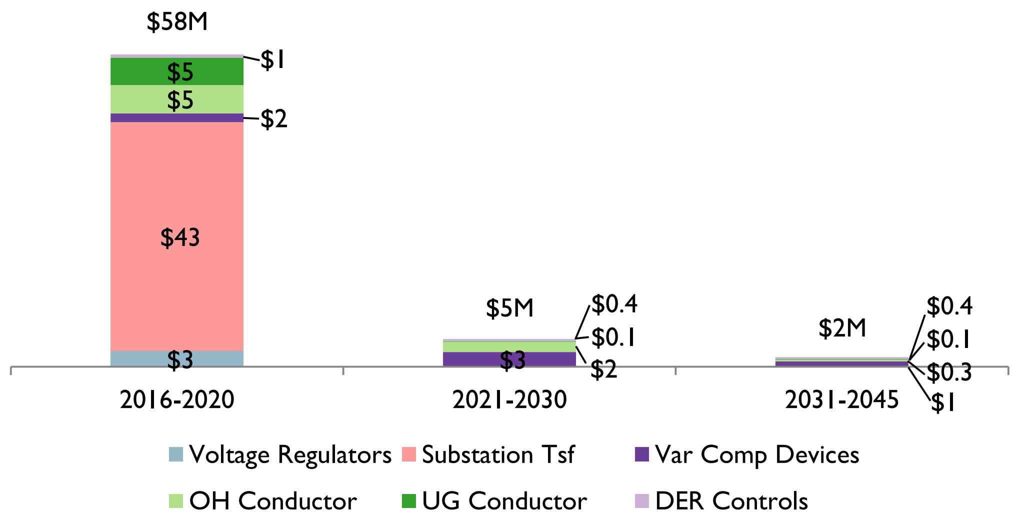

Figure N-31. Strategy 3 Annualized Integration Costs: Maui (Nominal $M)

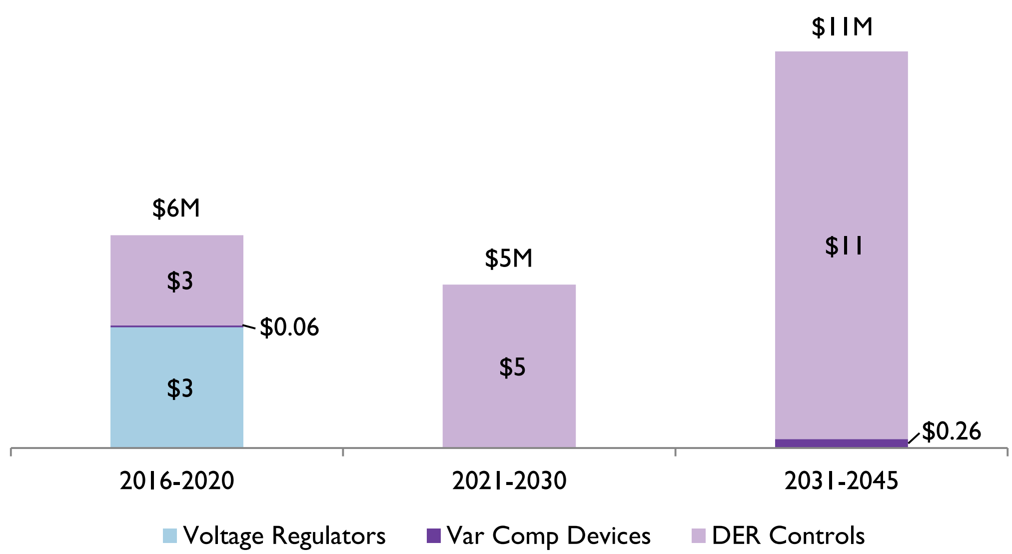

Figure N-32. Strategy 3 Annualized Integration Costs: Hawai'i Island (Nominal $M)

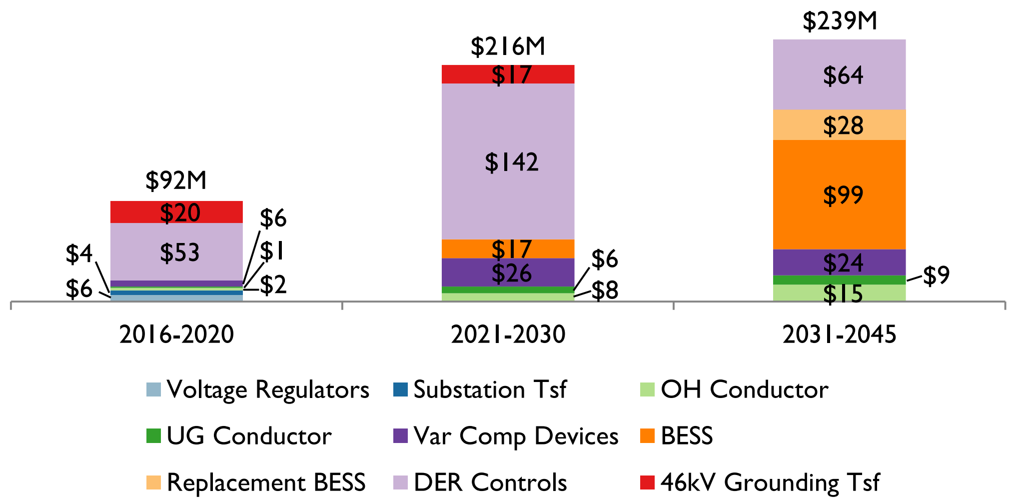

Figure N-33. Strategy 7 Annualized Integration Costs: O‘ahu (Nominal $M)

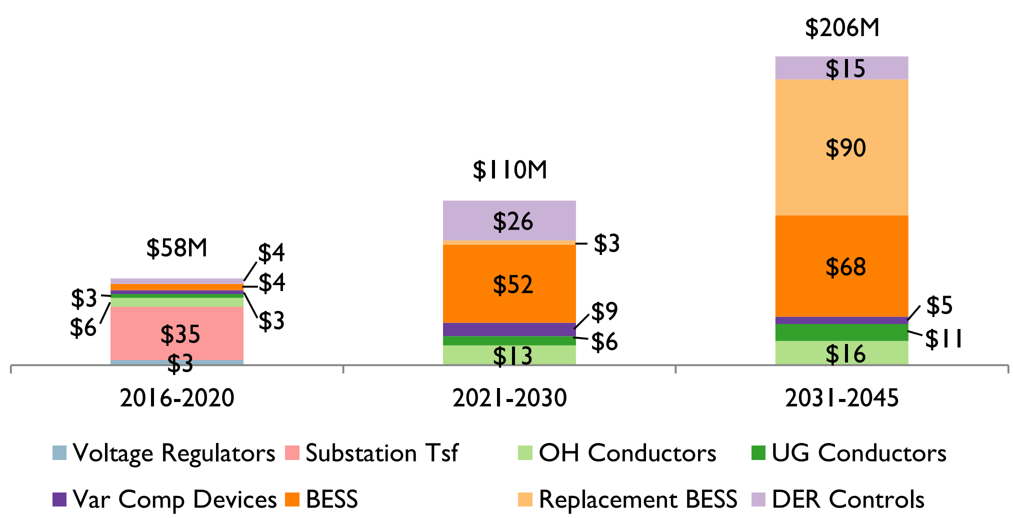

Figure N-34. Strategy 7 Annualized Integration Costs: Maui (Nominal $M)

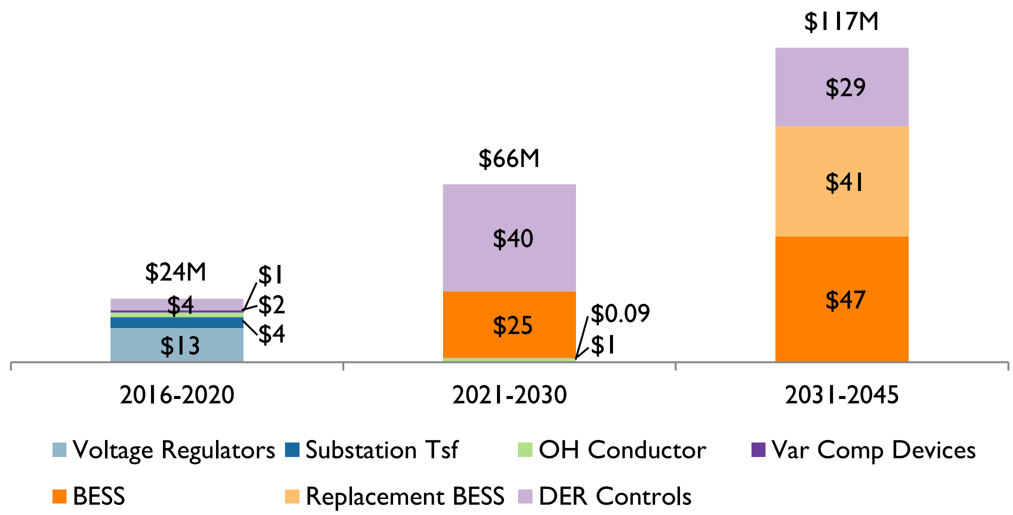

Figure N-35. Strategy 7 Annualized Integration Costs: Hawai'i Island (Nominal $M)

Results of Integration Cost Analysis

Figure N-36 and Figure N-37 show the comparative costs for the different integration strategies for both the market and high DG-PV case per island in nominal dollars with a 1.8% escalation rate.

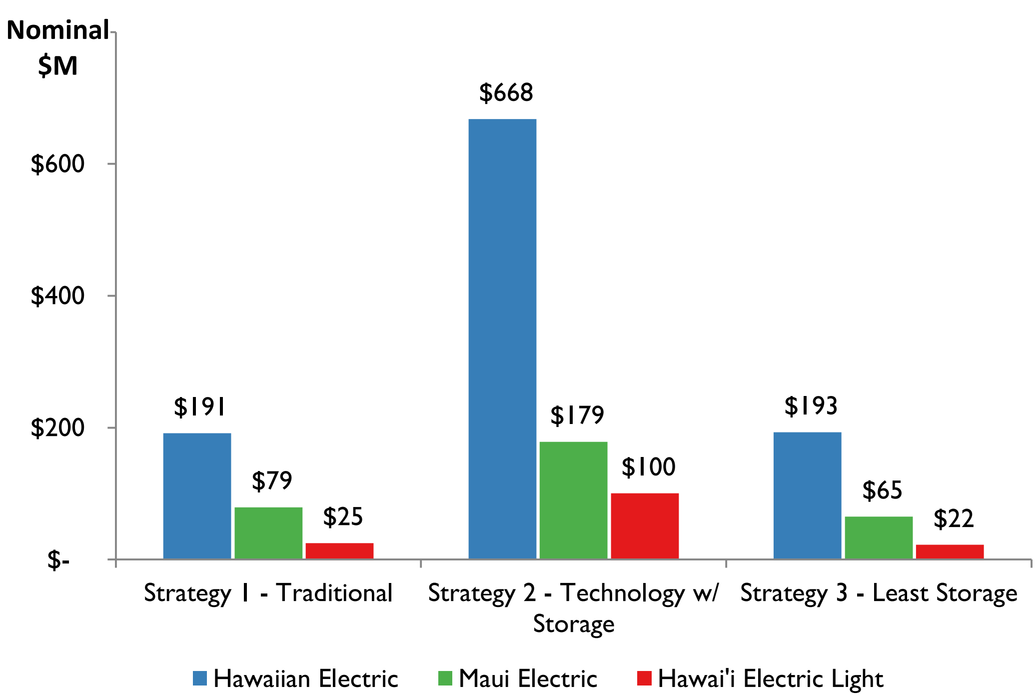

Figure N-36. Market DG-PV Forecast Total Integration Cost by Strategy by Island

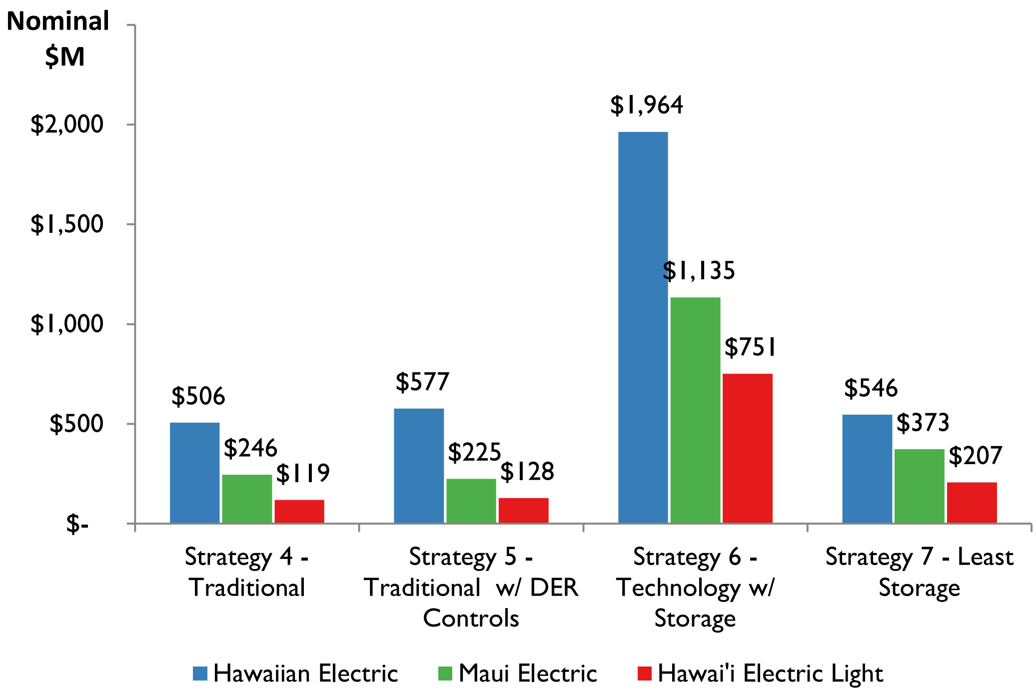

Figure N-37. High DG-PV Forecast Integration Cost by Strategy by Island

When viewing the 30-year planning horizon, the least storage option is cost competitive, relative to the other options, across the three islands in the market DG-PV case (for O'ahu the "traditional" strategy has a negligible cost difference when compared to the "least storage" strategy). However, in the high DG-PV case, the traditional integration strategy is the least cost strategy across the three islands. The least storage strategy becomes the most cost-effective if the cost to implement advanced inverter DER controls is significantly lower than that assumed in this analysis.

Distribution system planning typically tracks on 5- and 10-year planning horizons. With the on-going reform of distributed energy resource tariffs, factors such as, time of use, demand response, and electric vehicles make it difficult to predict future customer load shapes of residential and commercial circuits. The hosting capacity and resulting costs are sensitive to loading conditions coincident with PV production. The near-term 5-year integration costs provide a more accurate near-term assessment of the expected distribution system impacts.

As shown in Figures N-10 through N-12, the five-year DG-PV forecast in both the market and high-PV cases, remain relatively unchanged from the April 2016 PSIP Update. Table N-9 summarizes the near-term capital expenditures for each strategy in the April 2016 market DG-PV case, indicating that the least storage strategy is the least cost strategy.

Island Grid	Strategy 1	Strategy 2	Strategy 3	Forecasted PV
O'ahu	$64M	$159M	$52M	608 MW
Maui	$62M	$79M	$58M	125 MW
Hawai'i Island	$9M	$35M	$6M	112 MW

Table N-9. Near-Term Cost Comparison, Market PV Strategies, 2016-2020

Table N-9 summarizes the near-term capital expenditures for each strategy in the April 2016 high-PV case, indicating that the traditional wires and least storage strategies are the least cost strategies to integration in the near-term. However, because control capability of the inverters are required to execute Strategy 7, traditional wires solutions are likely the most feasible in the very near-term.

Island Grid	Strategy 4	Strategy 5	Strategy 6	Strategy 7	Forecasted PV
O'ahu	$102M	$145M	$212M	$92M	572 MW
Maui	$70M	$64M	$179M	$58M	126 MW
Hawai'i Island	$22M	$22M	$39M	$24M	113 MW

Table N-10. Near-Term Cost Comparison, High-PV Strategies, 2016-2020

It is likely that a mix of solutions from different strategies resolves various integration issues in the near-term. We prioritize solutions that meet near-term interconnection needs but are also useful in the long term. These analyses represent a sound guide to the capital investments required to integrate various levels of DG-PV when considering a portfolio of solutions.

Full tabular results of the various strategies are provided "Integration Strategy Cost Estimates" (page N-99), including integration results for Lana'i and Moloka'i.

Step 5: Derive Integration Cost Estimates

The following cost curves (Figure N-38 through Figure N-43) specified in real or constant 2016-dollar terms define the relationship between total DG-PV megawatts interconnected and the associated integration costs. These cost curves can estimate the integration costs for a range of DG-PV with proper escalation rates applied.

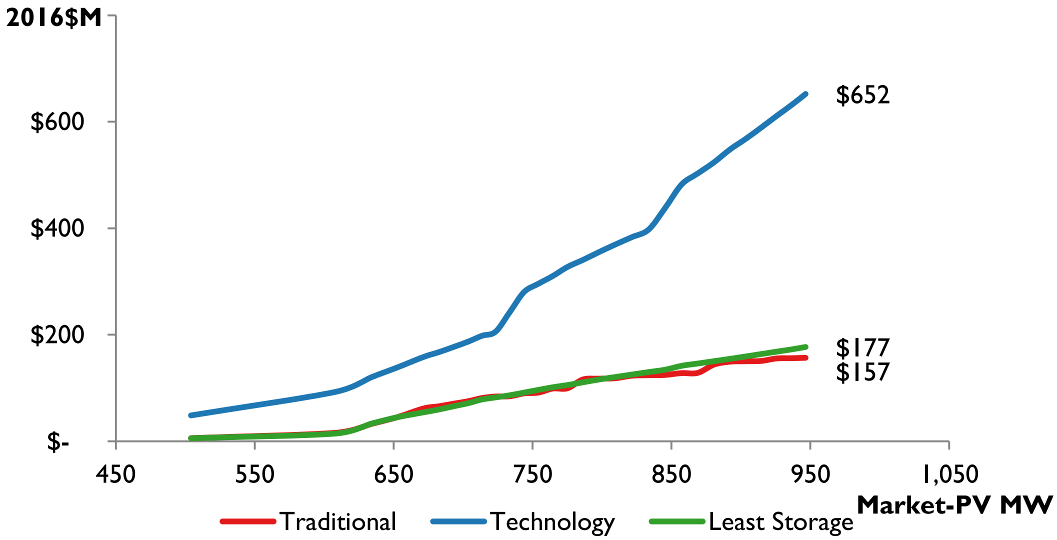

Figure N-38. Market DG-PV Integration Cost Curve by Strategy: O'ahu (Real $M)

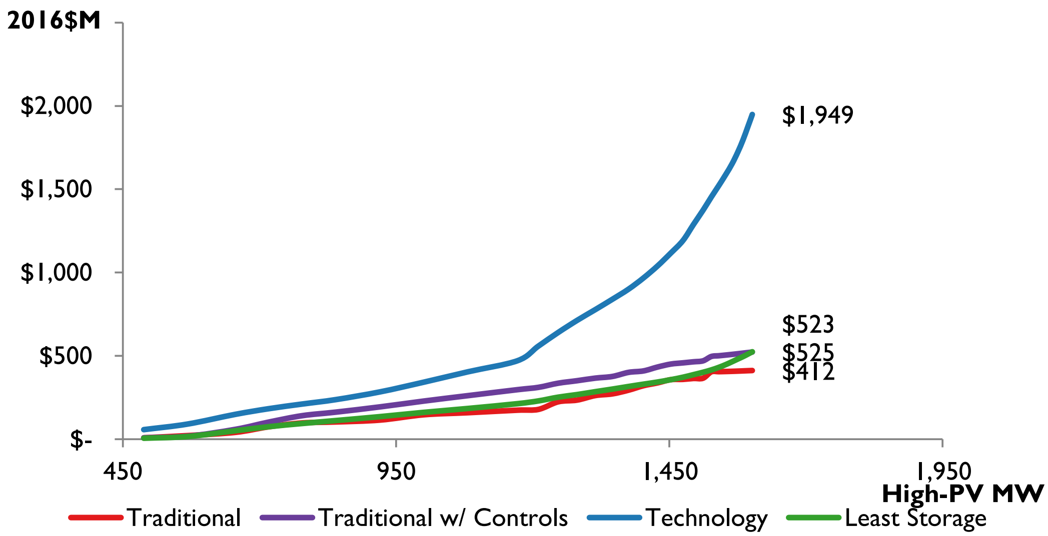

Figure N-39. High DG-PV Integration Cost Curve by Strategy: O'ahu (Real $M)

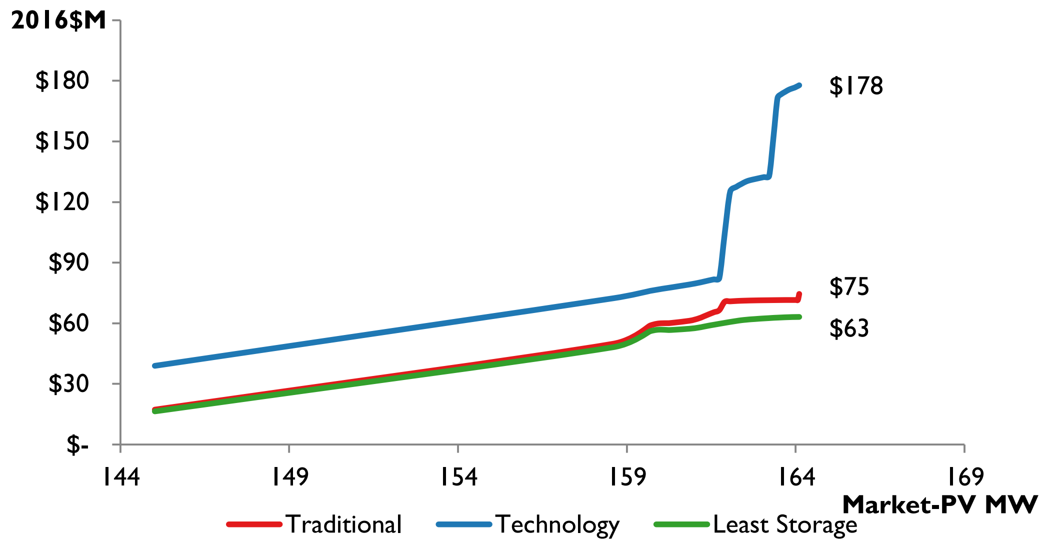

Figure N-40. Market DG-PV Integration Cost Curve by Strategy: Maui (Real $M)

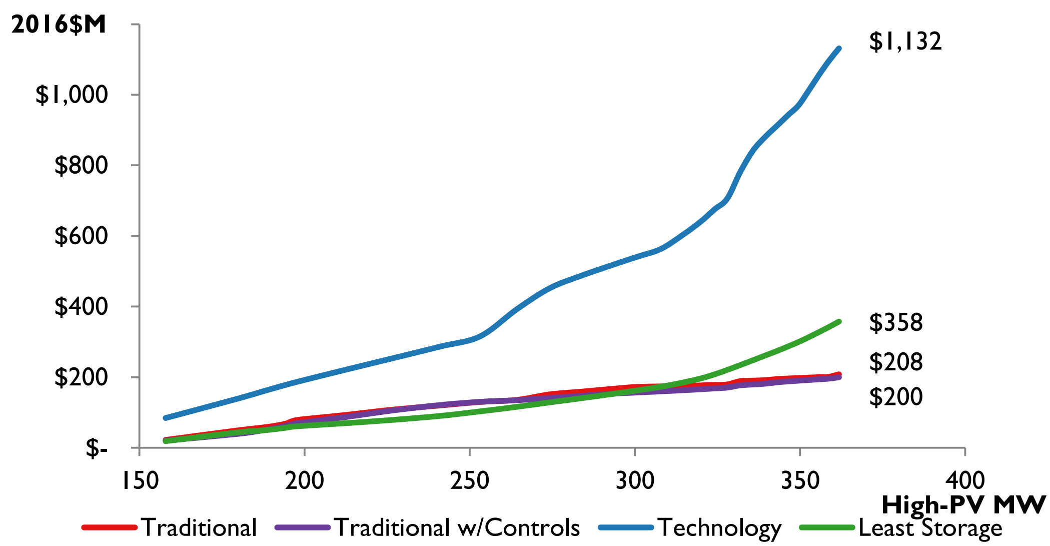

Figure N-41. High DG-PV Integration Cost Curve by Strategy: Maui (Real $M)

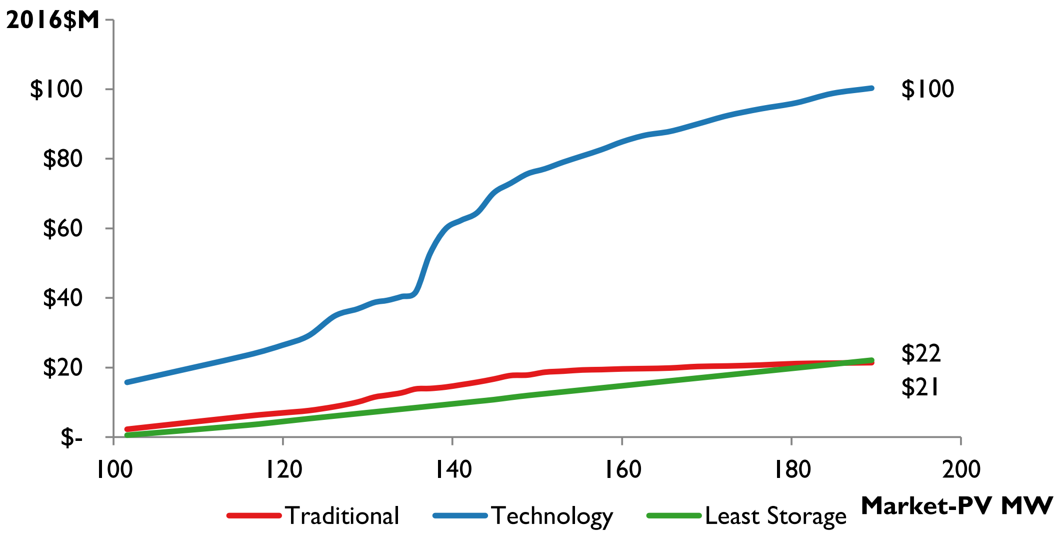

Figure N-42. Market DG-PV Integration Cost Curve by Strategy: Hawai‘i Island (Real $M)

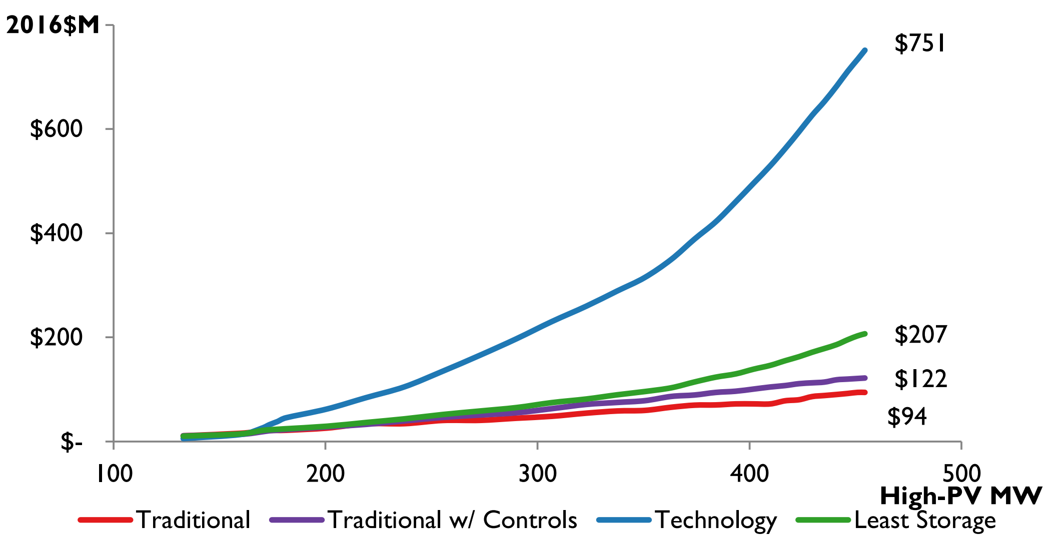

Figure N-43. High DG-PV Integration Cost Curve by Strategy: Hawai‘i Island (Real $M)

DG-PV Integration Progress

Since the DGIP filing in 2014, we have upgraded 64 load tap changer controllers on O‘ahu, totaling $380,000, which modernized our voltage regulation equipment to accommodate reverse power flow. We have completed research on ground fault overvoltage and no longer require grounding transformers at the distribution level.[13]

[13] Concerns, however, do remain with ground fault overvoltage on the sub-transmission (46kV) level. The 67 grounding transformers (totaling $4.4M) at Maui Electric and the 16 grounding transformers (totaling $1.1M) on Hawai‘i Electric

In 2016, to address the backlog of net energy metering customers and to increase overall circuit hosting capacities, we have executed meaningful circuit upgrades to facilitate DG-PV interconnection. Using our circuit models, hosting capacity simulations, and field data, we were able to determine primary system mitigations. Table N-11 describes the progress to-date in our efforts to prepare for future integration efforts.

Circuit Name	Primary System Violation	Solution
Circuit 2	High Voltage	Varentec pilot
Circuit 8	High Voltage	Optimized LTC settings
Circuit 27	High Voltage	4KV conversion, phase balancing and optimize LTC settings.
Circuit 49	High Voltage	Varentec pilot
Circuit 56	High Voltage	Re-configure circuit to phase balance and optimized LTC settings
Circuit 74	High Voltage	Optimized LTC and regulator settings
Circuit 78	High Voltage	Optimized LTC settings and phase balancing
Circuit 79	High Voltage	Solution pending
Circuit 93	High Voltage	Replace 3 voltage regulators, optimize regulator settings
Circuit 104	High Voltage	4KV conversion, phase balancing and optimize LTC settings.
Circuit 107	High Voltage	Optimize voltage regulator settings
Circuit 168	High Voltage	Optimized LTC settings
Circuit 186	High Voltage	Re-configure circuit to phase balance and optimized LTC settings
Circuit 192	High Voltage	Re-configure circuit to phase balance and optimized LTC settings
Circuit 228	High Voltage	Optimize voltage regulator settings
Circuit 258	High Voltage	Optimized LTC settings
Circuit 259	High Voltage, Thermal Overload	Upgrade conductor, optimize LTC settings
Circuit 285	High Voltage	Optimized LTC settings
Circuit 300	High Voltage	Optimized LTC and regulator settings
Circuit 327	High Voltage	Optimized LTC settings
Circuit 342	High Voltage	Optimized LTC settings
Circuit 359	High Voltage	Optimized LTC settings
Circuit 360	High Voltage	Optimized LTC settings
Circuit 361	High Voltage	Optimized LTC settings
Circuit 381	High Voltage	Optimized LTC settings

Table N-11. Oʻahu Distribution System DG-PV Primary Mitigation Efforts

The majority of solutions to-date optimized LTC settings. We are in the process of quantifying the resulting increase in hosting capacity; however, the next DG-PV program

Light, as stated in the DGIP, are no longer required in most situations provided PV systems meet our current transient overvoltage standards. See DGIP at 3-6.

will likely require additional solutions to solve high and low voltage deviations. As discussed in earlier sections, a mix of solutions such as, advanced inverter voltage functions, var compensation devices, conductor upgrades, and voltage regulators are key components to our future voltage regulation strategy.

SUB-TRANSMISSION INTEGRATION METHODOLOGY, SOLUTIONS, AND COSTS

With over 2,000 MW of rooftop PV and more than1800 MW of grid-scale solar forecasted to interconnect to the grid, integration impacts are expected on the sub-transmission system.

The sub-transmission capacity analysis will determine (1) the impact of rooftop PV to the sub-transmission system, and (2) the impact of future grid-scale wind and solar projects to the sub-transmission system.

The sub-transmission hosting capacity will analyze each line section to determine the amount of generation that can interconnect before triggering a criteria violation. The analysis is intended to provide regulators, policymakers, and energy developers information on the available capacity in various regions throughout the island.

Methodology

Voltage power quality and equipment thermal capacity of the sub-transmission lines were the focus of the initial iteration of the sub-transmission hosting capacity. Many other PV or wind generation impacts are specific to the size of the proposed grid-scale project, its operating characteristics, and its point of interconnection. A specific project's Interconnection Requirements Study will evaluate other potential impacts.

Sub-Transmission Hosting Capacity was determined by performing a steady-state load flow with Synergi Electric Software. Synergi created the Section Incremental Hosting Capacity tool specific for performing sub-transmission hosting capacity.

Within the load flow model, we allocated the circuit daytime minimum load at each Distribution Substation Transformer, along with its forecasted PV amount from the April 2016 market forecast and known grid-scale projects through 2019.

Table N-12 describes the criteria used in this analysis based upon Hawaiian Electric's sub-transmission planning criteria.

Parameter	Criteria
Voltage	+4.34% to -10% of nominal
Conductor Loading	100% of the normal ampacity rating of the conductor
Transformer Loading	During normal loading conditions, 100% of the zero percent loss-of-life kVA capability, which is normally at least the nameplate rating of the transformer.

Table N-12. Sub-Transmission Hosting Capacity Criteria

The voltage criterion is much wider in comparison to the distribution system (± 5% of nominal) because the majority of customers are located on the distribution system, and voltage is regulated at downstream regulation devices.

Voltage and Capacity

Figure N-44 depicts a simple representation of a generic sub-transmission circuit, which shows the sub-transmission line typically connected to our transmission substation transformers with a voltage rating of 138,000 volts to 46,000 volts. In the model, each sub-transmission line is broken up into sections.

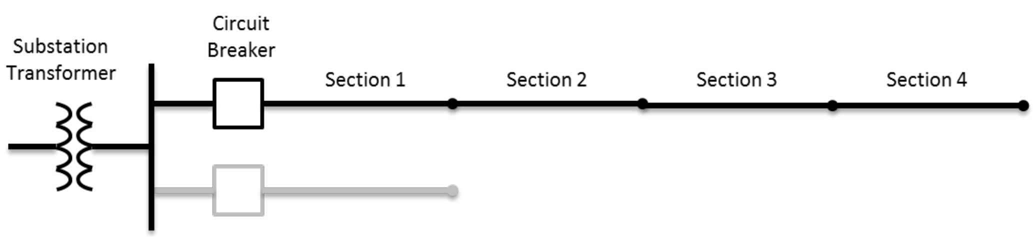

Figure N-44. Simplified Representation of Generic Sub-Transmission Circuit

The following describes the sub-transmission hosting capacity process:

1. Place a distributed generator one section at a time, with an initial size of 1 kW, starting with Section 1.
2. Increase generator size on section until violation of any of the criteria described in Table N-12 occurs.
3. Record maximum generator size without any violations. This is the available hosting capacity for that line section.
4. Remove generator from Section.
5. Repeat process for next sub-transmission line section.

Figure N-45 illustrates the simplified output of a sub-transmission analysis.

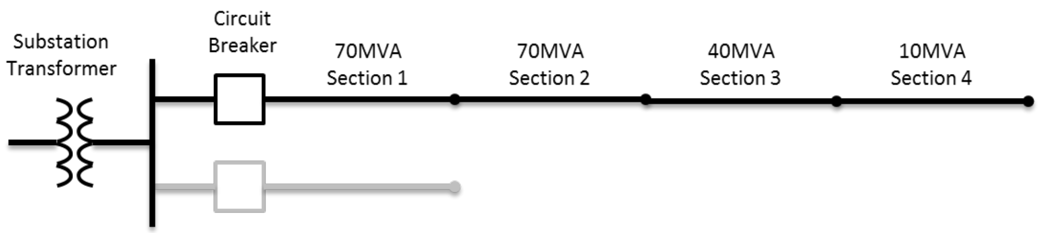

Figure N-45. Simplified Results of the Section Incremental Capacity Tool

The available hosting capacity only applies to the first project placed onto a sub-transmission line beyond the base case. Each time a project is or proposed to be interconnected; the hosting capacity must be re-run with the new base case to determine the available hosting capacity for future projects. The available capacity is highly dependent on a project's point of interconnection.

During the procurement process, an Interconnection Requirements Study will resolve any impacts associated with multiple projects interconnecting to the same sub-transmission line.

Results

The sub-transmission hosting capacity analysis included the April 2016 market forecast of 971 MW. In comparison to the current high DG-PV forecast, 971 MW is the expected level of PV adoption in 2027. The next iteration of the sub-transmission hosting capacity will update the model with the most current distributed PV forecast.

Based upon 971 MW of distributed PV, the analysis shows a Wahiawa sub-transmission conductor overload for 17 miles. The wind farms located on the north shore consume the majority of the capacity on this line. Further, the overloaded portions of the sub-transmission line already have the largest available overhead 46,000-volt conductor installed. Notwithstanding the Wahiawa transmission constraint, additional transmission infrastructure will be required on the central and north side of the island to expand renewable energy development. In its current state, additional rooftop PV and gird-scale resources are severely capacity limited on the north side of the island.

Utilizing the preliminary sub-transmission hosting capacity analysis, we calculated each sub-transmission line PV penetration as a function of its daytime minimum load. PV penetration of daytime minimum load in excess of 120% served as a proxy to determine the likelihood of ground fault overvoltage. As shown in Figure N-46, 35 of the 58 circuits will potentially require ground fault overvoltage mitigation based on the 2045 April 2016 market forecast. An Interconnection Requirements Study will determine the timing, and whether mitigation is required because ground fault overvoltage is dependent on the amount of load, nameplate generation, equipment ratings, and impedance of the circuit; each case is unique.

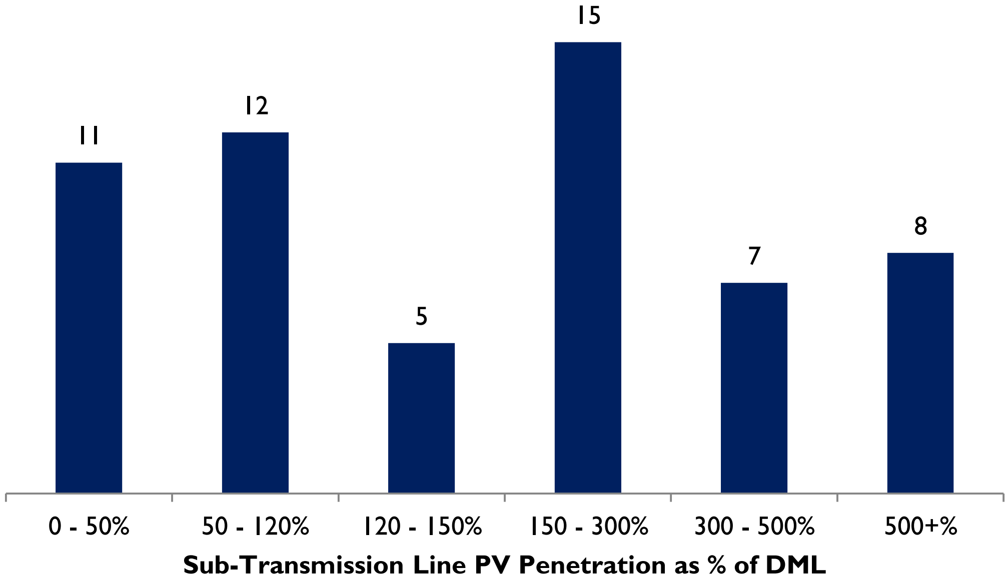

Figure N-46. Number of Sub-Transmission Circuits by Percentage of Daytime Minimum Load

Solutions and Costs

Accurate estimates of the scope and cost of potential mitigations at the sub-transmission level rely heavily on the location and the operation of the generating resource. This section intends to discuss solutions, and where possible quantifying those costs. The actual mitigations and costs are determined through detailed analysis such as an Interconnection Requirements Study.

Conductor and Equipment Overload

Grid-scale projects can expect to face sub-transmission conductor upgrades, particularly in the high solar potential areas determined in NREL's analysis. Projects interconnecting farther from the substation tend to require capacity upgrades because of the smaller conductors typically installed. The largest overhead sub-transmission conductor has a capacity of 55 MVA, and transmission substation transformers (138,000 volts to 46,000 volts) have a maximum rating of 80 MVA.

These sub-transmission limitations drive the need to expand existing transmission infrastructure to increase capacity for grid-scale projects.

It is difficult to estimate the quantity of conductor upgrades; however, the sub-transmission hosting capacity serves as a tool to determine remaining capacity. Projects requiring a conductor upgrade, can expect to pay approximately $3.4M per mile of overhead 46,000-volt conductor.

Ground Fault Overvoltage

Table N-13 tabulates the quantity and cost of expected grounding transformer upgrades required by 2045 using the April 2016 market forecast.

Grounding Transformer	2016–2020	2021–2030	Total
Quantity	20	15	35
Cost ($MM)	$19	$14.25	$33.25

Table N-13. Grounding Transformer Requirements, High DG-PV Forecast

Hawaiian Electric modified their interconnection requirements for grid-scale resources to require interconnection transformers (delta to grounded wye) that provide effective grounding. Less grounding transformers than estimated here would be required if a sub-transmission line is effectively grounded by a grid-scale resource.

Near-Term Sub-Transmission and Transmission Constraints

* Based on Wahiawa transmission constraint of 94 MW less FIT-3 and Waiver Projects (85 MW), Wahiawa Sub-Transmission Lines are limited to 9 MW.

Table N-14 below summarizes the transmission constraints on all three major islands.

Island	Area	MW Capacity
O'ahu (Sub-Transmission)	Wahiawa*	9
	Waiau-Mililani	70
	Kahe 1	24
	Kahe 2	42
	Ewa	81
O'ahu (Transmission)	Kahe Bus	209
Maui (Transmission)	South Maui	15
	Kaheawa	115
Hawai'i Island (Transmission)	Lalamilo	70

* Based on Wahiawa transmission constraint of 94 MW less FIT-3 and Waiver Projects (85 MW), Wahiawa Sub-Transmission Lines are limited to 9 MW.

Table N-14. High-Level Estimate of Transmission and Sub-Transmission Constraints, by Island.

Near-Term O'ahu Sub-Transmission Constraints

Figure N-47 details the hosting capacity analysis of the sub-transmission lines in the areas of grid-scale solar potential as analyzed by NREL (See Appendix F: NREL Reports). This analysis estimates the amount of available capacity to integrate grid-scale resources by 2020 without having to perform conductor upgrades. Each high solar potential region has a range of available capacity; the actual available capacity is dependent upon the point of interconnection. Capacity values were determined by aggregating the individual capacity of sub-transmission lines that pass near or through the brown and orange shaded solar potential areas.

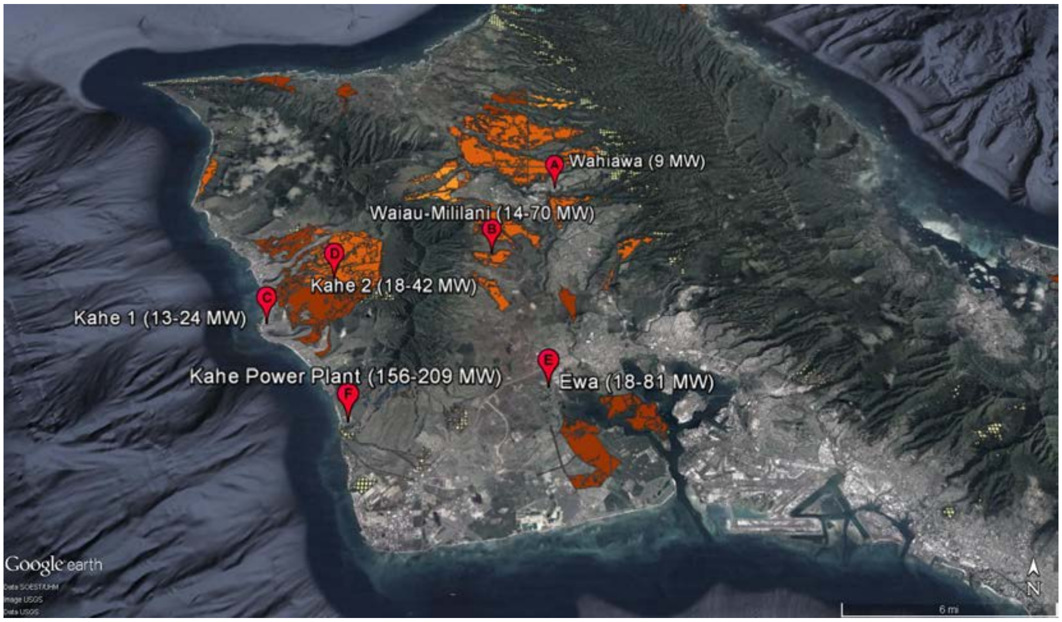

Figure N-47. Near-Term Sub-Transmission Capacity for Grid-Scale Resources by Solar Region

It is important to note that these hosting capacity figures are dependent on location. For example, if bid proposals for generation are concentrated in the Kahe area, the hosting capacity is limited to a maximum of 66 MW (depending on location). The maximum 226 MW (sum of regions A-E) assumes ideally placed projects within the designated regions; for example, projects interconnected closer to the substation more capacity tend to have greater capacity than those at the end of a sub-transmission line.

Near-Term Maui Transmission Constraints

An additional 15MW of wind can interconnect to South Maui without triggering a new transmission line (assumes ICEs and load shifting BESS in South Maui). The South Maui area is served with one 69 kV line looped from Ma'alaea Power Plant through Kealahou area to South Maui and back to Ma'alaea Power Plant. Load flow analyses determined that under normal conditions, the maximum amount of generation that can interconnect in the South Maui area is approximately 56 MW, which is the normal capacity of the 69 kV line. With the existing Auwahi Wind Farm capacity of 21 MW and assuming a proposed new ICE generator of 20 MW (identified to support voltage in the South Maui area), approximately 15 MW of additional wind generation can be added to the South Maui area.

An additional 115MW of wind can interconnect to Kaheawa. There are three 69 kV lines passing thru the Kaheawa wind farm area serving the West Maui load. Load flow analyses determined that during the loss of the Ma'alaea-Lahaina #3 69 kV circuit (N-1 contingency), the maximum amount of generation that can be accommodated in the Kaheawa area is approximately 166 MW based on the 64 MW emergency rating for each of the remaining two lines and a West Maui load of 38 MW during light-load conditions. With the existing Kaheawa wind farm capacity of 51 MW, approximately 115 MW additional generation can be added to the Kaheawa area.

Voltage problems, which require further evaluation, can occur in Central Maui and South Maui as renewable generation replaces generation from Kahului Power Plant and Ma'alaea Power Plant.

Near-Term Hawai'i Island Transmission Constraints

Up to 70 MW of wind can interconnect in the Lalamilo area. Up to 70 MW of wind interconnect in the Lalamilo area depending upon its interconnection to the system. If directly connected to the Waimea 69 kV substation, 70 MW can be interconnected. Other interconnection options may reduce the wind capacity in the area

Keahole STCC is required for voltage support. Keahole STCC is needed for voltage support when net load is around 130-140 MW and there is no wind output. Under these conditions, the absence of Keahole STCC exposes the West area of the island to voltage collapse when the 7700 line trips.

Transmission Integration Solutions

The limited sub-transmission capacity will require an expansion of transmission infrastructure on O'ahu for grid-scale resources beyond 2020. As illustrated in Figure N-48, the E3 plans call for significant amounts of grid scale resources.

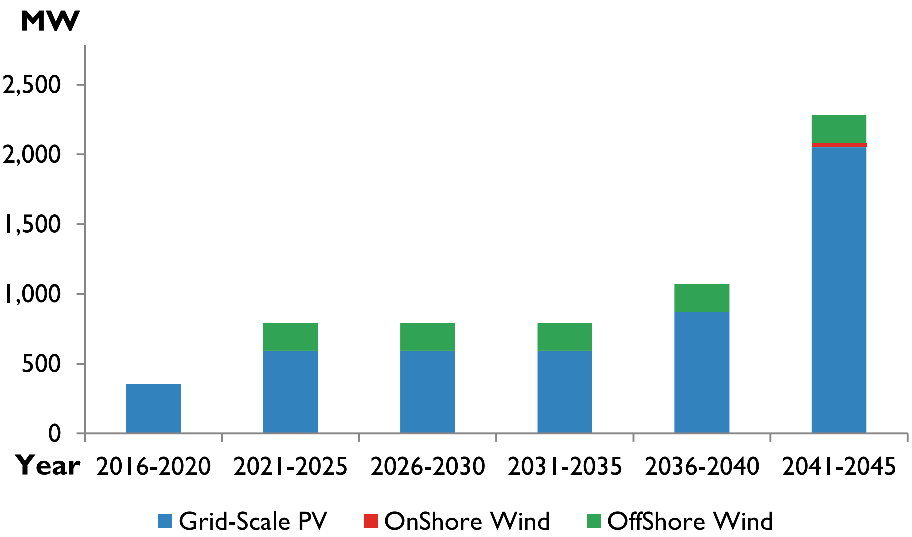

Figure N-48. Cumulative Renewable Grid-Scale Resources; E3 Plans (No LNG)

The Oʻahu transmission system does not extend to the far west or north shores of the island. However, the majority of the solar and wind resources on the island are located in these areas. To address capacity constraints, the following figure depicts an approximation of additional transmission infrastructure that would be required.

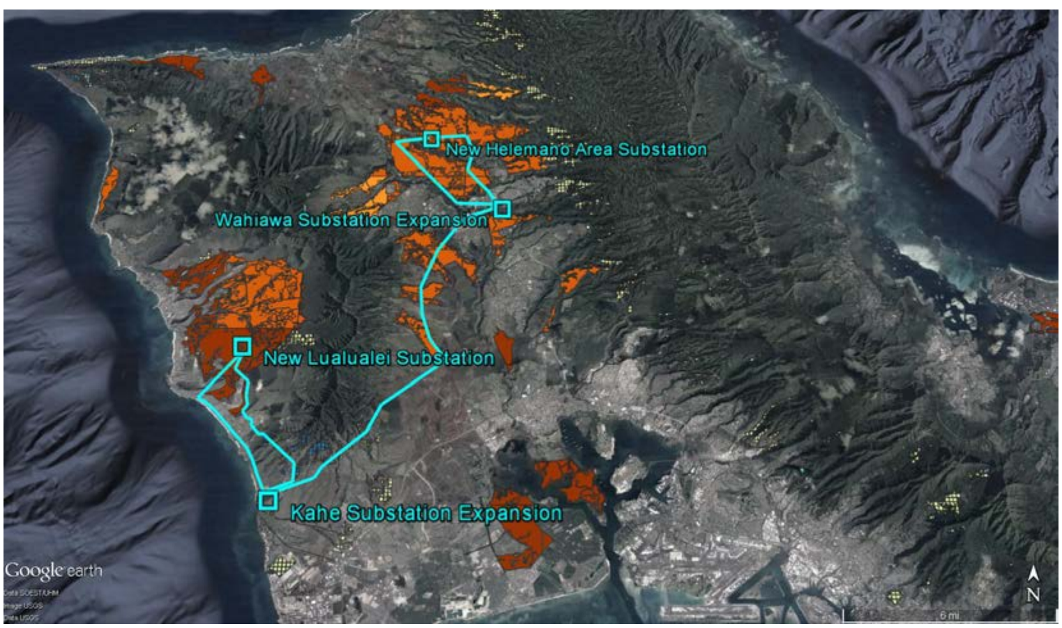

Figure N-49. Approximate 138 kV Transmission System Expansion to Accommodate Grid-Scale PV in High-Potential Areas

Building additional sub-transmission lines to interconnect grid-scale resources is a feasible alternative; however, may prove costlier. For example, take the Lualualei Area shown in Figure N-49, if 200 MW of grid-scale resources wanted to interconnect in that area, it would take four sub-transmission lines (55 MVA capacity each at N-1 reliability) versus two (N-1-1 reliability) transmission lines that can be overbuild on existing sub-transmission pole easements.

Battery Energy Storage Alternative

Load shifting battery energy storage can partially avoid transmission upgrades; however, cannot fully mitigate transmission expansion if we are to realize the NREL solar potentials on O'ahu. While batteries distributed throughout the grid can reduce curtailment of as-available generation, relieving thermal capacity overloads (on the sub-transmission system) will require the batteries to be located close to the overload or co-located with the PV facility.

Similar to daytime PV congestion, significant amounts of batteries (2,000 MW) as selected in the E3 plans, co-located with PV systems in the NREL high solar potential areas will encounter sub-transmission capacity issues. Using batteries to avoid thermal overloads means that the batteries must discharge daily to free battery capacity for the next day to store the excess PV generation that would otherwise overload a sub-transmission line.

For example, the dark brown area around the New Lualualei Substation in Figure N-49 has 200 MW of solar potential. Currently, the Kahe-Mikilua sub-transmission line runs through that area. Figure N-50 uses the following assumptions:

- System load profile with DR (Theme 1) on August 19, 2025 scaled downward to the expected proportionate load on the Kahe-Mikilua line.
- 200 MW of grid-scale PV scaled based on the PV profile from the E3 Plan, High DG-PV case without LNG on August 19, 2025.
- 130 MW 4-hour load shifting battery scaled based on the load shifting battery profile from the E3 Plan, High DG-PV case without LNG on August 19, 2025.
- The net load is the difference between the generation and load sources.

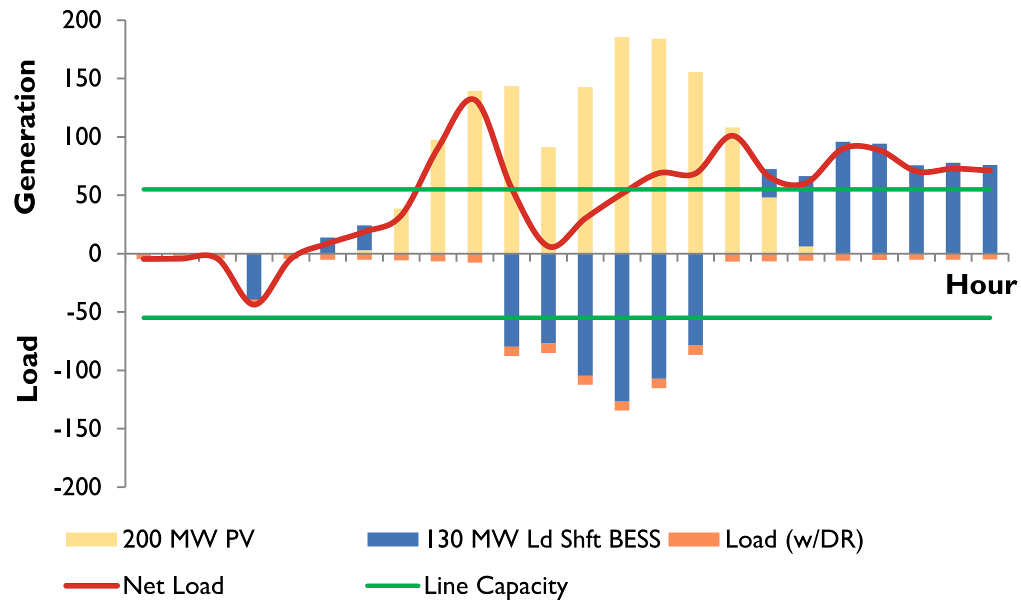

Figure N-50. Sub-Transmission Loading for a 200 MW PV + 130 MW BESS Project

Assuming the sub-transmission line is upgraded to the maximum 55 MVA capacity, Figure N-50 demonstrates that with a battery, capacity overloads can occur during PV and non-PV hours.

Figure N-51 illustrates the same scenario as Figure N-50, with the exception of a 105 MW grid-scale PV plant instead. In this case, the sub-transmission line generally has enough capacity to accommodate the PV output and battery discharge. However, to maximize the solar potential in this area, we would need to build a new sub-transmission or transmission line.

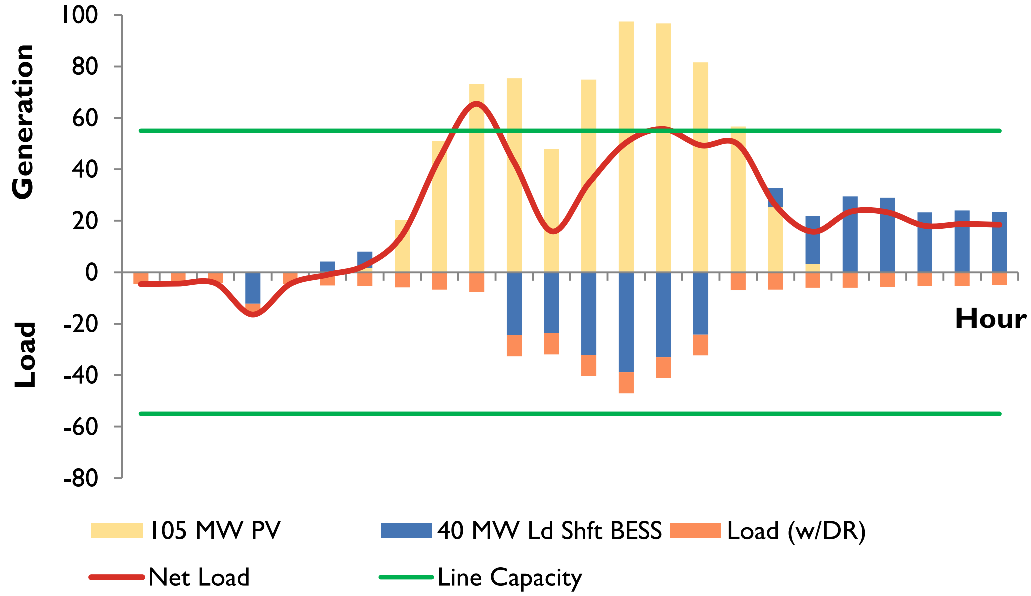

Figure N-51. Sub-Transmission Loading for a 105 MW PV + 40 MW BESS Project

Additional detailed analysis is required to assess other impacts as well as the feasibility and cost-effectiveness of battery storage to avoid transmission upgrades, which will depend on the location and capacity of the resources.

DG-PV FORECASTS BY DISTRIBUTION CIRCUIT

DG-PV forecasts for all circuits on our three major grid are presented in Table N-15 through Table N-20 for Hawaiian Electric, Maui Electric, and Hawai'i Electric Light circuits.

Legend: OCL = Operational Circuit Limit; HC = Posted Hosting Capacity

Hawaiian Electric Distribution Circuit Market DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,044	5,137	1,119	1,372	1,432	1,479	1,522	1,803	2,170	2,170
Circuit 2	5,170	2,392	3,308	4,055	4,233	4,370	4,499	5,287	5,287	5,287
Circuit 3	5,692	484	961	1,178	1,229	1,269	1,307	1,547	1,884	2,085
Circuit 4	361	307	–	–	–	–	–	–	–	–
Circuit 5	4,770	3,284	3,163	3,877	4,047	4,179	4,302	5,094	6,201	6,523
Circuit 6	2,556	2,173	383	470	490	506	521	617	751	831
Circuit 7	1,198	1,019	148	181	189	195	201	217	217	217
Circuit 8	1,940	319	1,020	1,250	1,305	1,348	1,387	1,643	2,000	2,214
Circuit 9	1,301	951	1,041	1,276	1,332	1,375	1,416	1,677	2,041	2,058
Circuit 10	5,107	4,341	2,003	2,456	2,564	2,647	2,725	3,227	3,928	4,348
Circuit 11	689	585	–	–	–	–	–	–	–	–
Circuit 12	1,714	1,457	–	–	–	–	–	–	–	–
Circuit 13	6,272	5,331	154	188	196	203	209	247	301	333
Circuit 14	573	438	635	778	813	839	864	960	960	960
Circuit 15	5,750	4,887	3,480	4,266	4,454	4,598	4,734	5,606	6,824	7,553
Circuit 16	5,701	1,825	2,208	2,706	2,825	2,917	3,003	3,556	4,329	4,791
Circuit 17	5,699	4,605	2,659	3,259	3,402	3,513	3,616	4,282	5,213	5,677
Circuit 18	2,402	2,042	–	–	–	–	–	–	–	–
Circuit 19	3,003	2,553	–	–	–	–	–	–	–	–
Circuit 20	7,330	6,185	529	648	677	699	719	852	1,037	1,148
Circuit 21	5,331	4,499	178	218	228	235	242	287	349	386
Circuit 22	4,733	3,901	–	–	–	–	–	–	–	–
Circuit 23	6,741	5,747	1,055	1,293	1,350	1,393	1,434	1,699	2,068	2,289
Circuit 24	1,448	575	840	1,029	1,074	1,109	1,142	1,352	1,493	1,493
Circuit 25	7,601	4,006	2,933	3,595	3,753	3,875	3,989	4,724	5,750	6,365
Circuit 26	1,005	854	246	302	315	325	335	397	483	534
Circuit 27	771	465	568	696	727	750	772	915	1,113	1,233

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 28	4,190	3,686	565	693	723	747	769	910	1,108	1,226
Circuit 29	4,187	3,386	3,514	4,308	4,497	4,643	4,780	5,660	6,296	6,296
Circuit 30	6,569	5,583	1,144	1,402	1,464	1,511	1,556	1,842	2,243	2,483
Circuit 31	5,359	4,555	1,151	1,411	1,473	1,520	1,565	1,565	1,565	1,565
Circuit 32	1,211	1,029	457	560	585	604	622	736	833	833
Circuit 33	3,114	1,758	–	–	–	–	–	–	–	–
Circuit 34	3,107	2,641	–	–	–	–	–	–	–	–
Circuit 35	6,611	5,619	2,025	2,482	2,591	2,675	2,754	2,777	2,777	2,777
Circuit 36	4,151	3,635	208	255	266	275	283	335	408	452
Circuit 37	2,806	2,385	–	–	–	–	–	–	–	–
Circuit 38	4,488	3,737	273	334	349	361	371	439	535	592
Circuit 39	1,403	1,193	–	–	–	–	–	–	–	–
Circuit 40	1,873	249	1,865	2,286	2,387	2,464	2,537	2,673	2,673	2,673
Circuit 41	3,266	2,252	312	383	399	412	424	503	612	677
Circuit 42	3,126	2,657	–	–	–	–	–	–	–	–
Circuit 43	4,186	3,558	520	637	665	687	707	838	1,020	1,129
Circuit 44	5,293	1,234	283	347	362	374	385	455	554	614
Circuit 45	5,673	4,822	2,476	2,476	2,476	2,476	2,476	2,476	2,476	2,476
Circuit 46	1,380	1,161	1,074	1,316	1,374	1,419	1,460	1,666	1,666	1,666
Circuit 47	3,559	3,025	–	–	–	–	–	–	–	–
Circuit 48	4,529	3,850	–	–	–	–	–	–	–	–
Circuit 49	3,102	2,637	3,117	3,821	3,989	4,119	4,240	5,021	5,337	5,337
Circuit 50	5,323	4,426	2,909	3,566	3,722	3,843	3,956	4,685	5,703	5,913
Circuit 51	3,931	3,126	1,844	2,260	2,359	2,436	2,508	2,970	3,615	4,001
Circuit 52	4,736	2,867	2,292	2,809	2,932	3,028	3,117	3,691	4,493	4,973
Circuit 53	5,383	6,171	3,342	4,097	4,277	4,416	4,546	5,383	6,553	7,253
Circuit 54	4,830	4,355	3,074	3,768	3,870	3,870	3,870	3,870	3,870	3,870
Circuit 55	6,640	5,120	2,810	2,810	2,810	2,810	2,810	2,810	2,810	2,810
Circuit 56	2,289	1,001	763	935	976	1,007	1,037	1,228	1,495	1,655
Circuit 57	5,837	3,689	748	917	958	989	1,018	1,205	1,467	1,624
Circuit 58	3,014	2,562	4	4	5	5	5	6	7	8
Circuit 59	6,331	3,121	246	301	314	325	334	396	482	533
Circuit 60	3,667	3,117	338	415	433	447	460	545	663	734
Circuit 61	2,895	2,461	190	233	243	251	258	306	373	412
Circuit 62	4,599	4,180	2,446	2,998	3,130	3,231	3,326	3,939	4,795	5,308
Circuit 63	4,789	4,544	2,668	3,271	3,414	3,525	3,629	4,297	5,231	5,581
Circuit 64	4,747	4,445	4,837	5,929	6,021	6,021	6,021	6,021	6,021	6,021
Circuit 65	3,651	3,341	1,534	1,880	1,962	2,026	2,086	2,470	2,534	2,534

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 66	3,366	2,861	1,786	2,189	2,285	2,359	2,429	2,876	3,498	3,498
Circuit 67	4,703	3,402	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370
Circuit 68	4,308	3,662	1,984	2,433	2,539	2,622	2,699	3,196	3,549	3,549
Circuit 69	5,586	4,100	2,163	2,651	2,768	2,858	2,942	3,484	4,241	4,694
Circuit 70	4,351	3,698	1,461	1,791	1,870	1,931	1,987	2,353	2,865	3,171
Circuit 71	8,420	7,157	3,285	4,027	4,204	4,340	4,468	5,291	6,441	7,130
Circuit 72	930	506	8	10	10	11	11	13	16	18
Circuit 73	5,289	4,496	2,955	3,622	3,781	3,904	4,019	4,759	5,793	6,412
Circuit 74	6,899	841	1,018	1,248	1,303	1,345	1,385	1,640	1,996	2,209
Circuit 75	7,393	4,965	160	196	204	211	217	257	313	346
Circuit 76	3,528	2,999	–	–	–	–	–	–	–	–
Circuit 77	2,673	2,594	52	64	66	69	71	84	102	113
Circuit 78	7,301	1,140	3,048	3,737	3,901	4,027	4,146	4,910	5,936	5,936
Circuit 79	1,470	706	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894
Circuit 80	5,814	3,867	1,640	2,011	2,099	2,167	2,231	2,642	3,216	3,560
Circuit 81	5,352	3,730	2,687	3,294	3,439	3,551	3,655	4,328	5,269	5,832
Circuit 82	220	445	136	167	174	180	185	220	267	296
Circuit 83	1,968	1,673	904	904	904	904	904	904	904	904
Circuit 84	3,688	3,134	1,863	2,284	2,384	2,462	2,534	3,001	3,305	3,305
Circuit 85	5,288	4,495	1,168	1,431	1,494	1,543	1,588	1,881	2,289	2,534
Circuit 86	6,597	5,607	941	1,153	1,204	1,243	1,280	1,515	1,793	1,793
Circuit 87	5,113	5,647	2,759	3,382	3,530	3,645	3,752	4,443	4,758	4,758
Circuit 88	2,363	1,839	711	711	711	711	711	711	711	711
Circuit 89	2,488	2,419	1,052	1,290	1,347	1,390	1,430	1,430	1,430	1,430
Circuit 90	5,510	4,684	658	806	842	869	895	1,059	1,290	1,380
Circuit 91	1,351	474	593	727	759	784	807	956	1,163	1,288
Circuit 92	3,605	3,064	–	–	–	–	–	–	–	–
Circuit 93	2,416	1,356	1,537	1,884	1,966	2,030	2,090	2,466	2,466	2,466
Circuit 94	4,283	3,640	6	7	8	8	8	10	12	13
Circuit 95	6,936	5,896	3,372	3,372	3,372	3,372	3,372	3,372	3,372	3,372
Circuit 96	7,190	6,112	506	620	647	668	688	815	992	1,098
Circuit 97	7,570	6,435	–	–	–	–	–	–	–	–
Circuit 98	3,979	3,382	291	357	373	385	396	469	566	566
Circuit 99	13,437	10,102	–	–	–	–	–	–	–	–
Circuit 100	4,164	3,539	–	–	–	–	–	–	–	–
Circuit 101	4,381	3,724	3,140	3,849	4,018	4,149	4,271	5,058	6,157	6,527
Circuit 102	4,691	1,374	1,719	2,107	2,200	2,271	2,338	2,769	3,370	3,731
Circuit 103	6,866	5,836	1,490	1,826	1,907	1,969	2,026	2,358	2,358	2,358

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 104	2,085	1,079	1,324	1,623	1,694	1,749	1,800	2,132	2,596	2,873
Circuit 105	1,609	1,367	891	1,092	1,140	1,178	1,212	1,435	1,559	1,559
Circuit 106	6,462	2,525	1,555	1,906	1,989	2,054	2,114	2,504	3,048	3,374
Circuit 107	1,905	816	1,225	1,502	1,568	1,619	1,667	1,974	2,163	2,163
Circuit 108	5,240	3,794	2,262	2,773	2,894	2,989	3,076	3,643	4,435	4,909
Circuit 109	4,903	1,667	1,747	2,142	2,236	2,309	2,377	2,814	3,426	3,792
Circuit 110	349	296	330	404	422	436	448	531	584	584
Circuit 111	1,287	678	782	958	1,000	1,033	1,063	1,259	1,425	1,425
Circuit 112	3,746	3,184	2,622	3,214	3,355	3,464	3,566	4,079	4,079	4,079
Circuit 113	7,039	5,983	4,665	5,719	5,970	6,164	6,345	7,514	8,062	8,062
Circuit 114	5,755	4,892	3,272	4,011	4,187	4,323	4,450	5,270	6,416	7,101
Circuit 115	1,862	890	1,991	2,440	2,547	2,630	2,707	3,010	3,010	3,010
Circuit 116	1,393	697	905	1,110	1,158	1,196	1,231	1,458	1,775	1,861
Circuit 117	2,519	765	429	526	549	567	583	691	841	931
Circuit 118	430	700	6	8	8	8	9	10	12	14
Circuit 119	2,006	1,399	–	–	–	–	–	–	–	–
Circuit 120	4,969	3,214	320	392	410	423	435	516	628	695
Circuit 121	8,943	6,377	378	463	484	499	514	609	741	820
Circuit 122	2,169	1,102	873	1,070	1,117	1,153	1,187	1,405	1,711	1,847
Circuit 123	2,344	1,992	241	295	308	318	328	388	473	523
Circuit 124	4,831	4,107	–	–	–	–	–	–	–	–
Circuit 125	1,435	1,086	1,671	1,671	1,671	1,671	1,671	1,671	1,671	1,671
Circuit 126	6,644	4,806	–	–	–	–	–	–	–	–
Circuit 127	5,187	4,409	–	–	–	–	–	–	–	–
Circuit 128	1,604	1,364	415	509	532	549	565	669	815	902
Circuit 129	1,681	916	666	816	852	880	905	1,072	1,305	1,445
Circuit 130	1,352	1,086	343	420	439	453	467	552	673	744
Circuit 131	2,267	1,446	748	917	957	988	1,017	1,204	1,466	1,623
Circuit 132	2,449	2,082	518	518	2,018	2,018	3,518	3,518	3,518	3,518
Circuit 133	5,337	4,536	1,058	1,297	1,354	1,398	1,439	1,705	2,075	2,297
Circuit 134	2,267	1,002	911	1,117	1,166	1,204	1,239	1,467	1,786	1,977
Circuit 135	2,752	515	1,026	1,258	1,313	1,356	1,396	1,653	2,012	2,227
Circuit 136	4,602	2,088	600	736	768	793	816	840	840	840
Circuit 137	1,505	1,809	8	10	10	11	11	13	16	17
Circuit 138	5,753	5,889	1,214	1,488	1,554	1,604	1,651	1,956	2,381	2,635
Circuit 139	3,459	2,468	3,029	3,713	3,876	4,002	4,119	4,598	4,598	4,598
Circuit 140	3,856	3,863	773	948	990	1,022	1,052	1,246	1,516	1,679
Circuit 141	2,659	1,905	1,736	2,128	2,221	2,293	2,361	2,796	3,403	3,767

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 142	2,792	2,539	998	998	998	998	998	998	998	998
Circuit 143	1,889	1,583	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
Circuit 144	8,363	7,109	600	736	768	793	816	966	1,176	1,302
Circuit 145	6,223	5,290	300	368	384	396	408	483	588	651
Circuit 146	6,528	5,549	2,207	2,706	2,825	2,916	3,002	3,555	4,328	4,790
Circuit 147	3,308	2,812	132	162	169	175	180	213	259	287
Circuit 148	2,783	2,366	1,694	2,076	2,167	2,238	2,304	2,728	3,321	3,676
Circuit 149	6,292	5,081	569	697	728	751	773	916	1,115	1,234
Circuit 150	2,983	2,028	272	334	348	360	370	439	470	470
Circuit 151	5,020	4,267	2,519	3,088	3,223	3,328	3,426	4,057	4,618	4,618
Circuit 152	5,741	3,499	587	719	751	775	798	945	1,150	1,273
Circuit 153	4,106	2,067	232	284	296	306	315	373	454	503
Circuit 154	4,941	1,152	–	–	–	–	–	–	–	–
Circuit 155	5,774	4,908	–	–	–	–	–	–	–	–
Circuit 156	4,879	4,147	–	–	–	–	–	–	–	–
Circuit 157	3,629	3,084	87	87	87	87	87	87	87	87
Circuit 158	889	499	316	387	404	417	420	420	420	420
Circuit 159	2,132	984	589	722	754	778	801	949	1,155	1,278
Circuit 160	5,736	4,137	535	656	684	707	728	862	1,049	1,161
Circuit 161	6,310	4,551	1,246	1,527	1,594	1,646	1,694	2,007	2,443	2,704
Circuit 162	4,056	3,448	364	446	465	480	494	585	713	789
Circuit 163	1,911	1,624	206	208	208	208	208	208	208	208
Circuit 164	725	920	629	629	629	629	629	629	629	629
Circuit 165	1,877	1,595	–	–	–	–	–	–	–	–
Circuit 166	1,032	877	398	487	509	525	541	640	670	670
Circuit 167	5,120	4,352	578	709	740	764	786	931	1,133	1,254
Circuit 168	3,546	963	1,226	1,503	1,569	1,620	1,667	1,974	2,404	2,660
Circuit 169	4,029	2,935	3,628	4,447	4,643	4,794	4,935	5,623	5,623	5,623
Circuit 170	1,120	952	409	502	524	541	557	659	803	806
Circuit 171	4,969	3,827	248	304	318	328	338	400	487	539
Circuit 172	2,755	2,342	362	443	463	478	492	582	709	785
Circuit 173	624	531	442	442	442	442	442	442	442	442
Circuit 174	3,230	2,745	928	1,137	1,187	1,226	1,262	1,494	1,537	1,537
Circuit 175	7,927	5,784	692	848	885	914	941	1,114	1,356	1,501
Circuit 176	721	613	–	–	–	–	–	–	–	–
Circuit 177	4,497	3,822	1,617	1,982	2,069	2,136	2,199	2,604	2,747	2,747
Circuit 178	7,024	6,024	1,275	1,562	1,631	1,684	1,734	2,053	2,299	2,299
Circuit 179	3,851	3,052	115	141	147	151	156	185	225	249

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 180	5,782	4,088	83	102	106	109	113	133	162	180
Circuit 181	83	62	–	–	–	–	–	–	–	–
Circuit 182	3,416	2,510	116	142	148	153	157	186	227	251
Circuit 183	11,185	9,507	500	613	640	661	680	805	980	1,085
Circuit 184	5,907	5,021	270	331	346	357	367	435	529	586
Circuit 185	6,299	5,354	1,945	2,384	2,489	2,570	2,646	3,133	3,557	3,557
Circuit 186	1,088	707	957	1,174	1,225	1,265	1,302	1,542	1,877	2,070
Circuit 187	3,487	2,964	355	435	454	469	483	572	696	771
Circuit 188	6,420	5,641	282	346	361	373	384	455	554	613
Circuit 189	60	52	–	–	–	–	–	–	–	–
Circuit 190	4,546	3,864	–	–	–	–	–	–	–	–
Circuit 191	3,108	2,642	2,350	2,881	3,008	3,105	3,197	3,786	4,009	4,009
Circuit 192	1,030	450	635	778	812	838	863	1,022	1,244	1,377
Circuit 193	3,249	759	–	–	–	–	–	–	–	–
Circuit 194	4,897	4,163	1,897	2,325	2,427	2,506	2,580	2,874	2,874	2,874
Circuit 195	4,138	3,518	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373
Circuit 196	7,671	6,520	2,649	3,247	3,389	3,500	3,603	4,266	5,193	5,748
Circuit 197	10,634	9,039	4,440	5,443	5,682	5,867	6,040	7,152	8,053	8,053
Circuit 198	952	809	203	249	260	268	268	268	268	268
Circuit 199	4,410	3,749	1,676	2,054	2,145	2,214	2,280	2,699	3,154	3,154
Circuit 200	4,112	1,608	1,137	1,394	1,455	1,503	1,547	1,832	1,935	1,935
Circuit 201	4,019	3,416	2,551	3,127	3,264	3,370	3,470	4,109	4,697	4,697
Circuit 202	4,355	2,666	1,694	2,077	2,168	2,238	2,304	2,433	2,433	2,433
Circuit 203	505	430	87	107	111	115	118	140	144	144
Circuit 204	5,370	4,565	39	47	49	51	52	62	76	84
Circuit 205	983	835	–	–	–	–	–	–	–	–
Circuit 206	3,562	3,027	–	–	–	–	–	–	–	–
Circuit 207	4,274	3,083	58	71	74	76	78	93	113	125
Circuit 208	3,627	1,295	836	1,024	1,069	1,104	1,136	1,346	1,638	1,813
Circuit 209	1,711	1,454	545	668	697	720	741	878	1,069	1,118
Circuit 210	3,125	2,693	1,537	1,884	1,967	2,031	2,090	2,475	3,013	3,336
Circuit 211	6,616	5,808	3,213	3,938	4,111	4,245	4,370	5,175	6,300	6,973
Circuit 212	5,706	5,033	2,562	3,141	3,279	3,386	3,485	4,127	5,024	5,561
Circuit 213	1,903	1,471	1,139	1,396	1,457	1,505	1,549	1,834	2,233	2,471
Circuit 214	8,176	6,950	350	429	448	462	476	564	686	760
Circuit 215	5,354	3,717	1,590	1,949	2,035	2,101	2,163	2,561	2,780	2,780
Circuit 216	2,008	1,706	609	609	609	609	609	609	609	609
Circuit 217	5,447	4,630	1,120	1,373	1,433	1,480	1,523	1,804	2,196	2,431

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 218	3,541	3,010	1,371	1,681	1,754	1,811	1,865	2,208	2,688	2,975
Circuit 219	179	152	–	–	–	–	–	–	–	–
Circuit 220	2,869	2,438	1,993	2,444	2,551	2,634	2,711	3,211	3,908	4,326
Circuit 221	6,009	4,641	1,722	2,111	2,204	2,276	2,343	2,774	3,377	3,738
Circuit 222	2,079	1,767	1,602	1,964	2,050	2,117	2,179	2,580	3,141	3,338
Circuit 223	5,005	2,998	907	1,112	1,160	1,198	1,233	1,461	1,778	1,968
Circuit 224	2,919	2,127	350	429	448	462	476	564	686	760
Circuit 225	8,145	6,776	863	1,058	1,105	1,141	1,174	1,391	1,693	1,874
Circuit 226	1,186	578	322	395	413	426	432	432	432	432
Circuit 227	190	162	35	42	44	46	47	56	68	75
Circuit 228	2,419	676	917	1,124	1,173	1,211	1,247	1,477	1,797	1,990
Circuit 229	7,351	6,249	2,573	3,154	3,293	3,400	3,500	4,144	5,045	5,550
Circuit 230	4,579	3,892	1,027	1,259	1,315	1,357	1,397	1,655	2,014	2,230
Circuit 231	2,090	1,777	599	735	767	792	815	965	1,175	1,301
Circuit 232	4,899	4,237	96	118	123	127	131	155	188	208
Circuit 233	7,858	4,263	2,930	3,591	3,749	3,871	3,985	4,719	5,744	6,358
Circuit 234	1,663	1,532	294	361	377	389	400	474	577	639
Circuit 235	5,011	4,027	2,338	2,866	2,916	2,916	2,916	2,916	2,916	2,916
Circuit 236	8,704	4,964	3,984	4,884	5,098	5,264	5,419	6,417	7,193	7,193
Circuit 237	4,312	4,027	2,592	3,177	3,316	3,424	3,525	4,174	5,081	5,615
Circuit 238	748	717	958	958	958	958	958	958	958	958
Circuit 239	3,566	3,031	1,897	2,326	2,428	2,507	2,580	3,056	3,720	4,118
Circuit 240	4,602	4,036	2	3	3	3	3	4	5	5
Circuit 241	8,243	6,839	2,600	2,833	2,833	2,833	2,833	2,833	2,833	2,833
Circuit 242	1,597	1,256	365	447	467	482	496	588	715	792
Circuit 243	177	2,344	–	–	–	–	–	–	–	–
Circuit 244	2,979	3,794	679	832	868	897	923	1,093	1,330	1,473
Circuit 245	5,261	3,543	2,168	2,658	2,775	2,865	2,949	3,492	4,251	4,387
Circuit 246	711	226	–	–	–	–	–	–	–	–
Circuit 247	4,259	3,857	438	537	560	578	596	705	858	950
Circuit 248	4,452	793	1,099	1,347	1,406	1,452	1,494	1,770	1,945	1,945
Circuit 249	3,632	432	228	280	292	302	310	368	448	495
Circuit 250	2,345	1,993	1,140	1,397	1,459	1,506	1,550	1,836	2,166	2,166
Circuit 251	8,975	5,107	8,105	9,935	10,372	10,709	11,024	12,473	12,473	12,473
Circuit 252	2,897	963	1,507	1,847	1,928	1,990	2,049	2,426	2,664	2,664
Circuit 253	108	92	–	–	–	–	–	–	–	–
Circuit 254	7,195	6,288	585	717	748	773	795	942	1,147	1,269
Circuit 255	5,548	5,328	536	657	686	709	729	864	1,052	1,164

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 256	3,836	3,624	726	890	930	960	988	1,170	1,424	1,576
Circuit 257	5,354	5,059	1,474	1,807	1,886	1,947	2,005	2,374	2,890	3,199
Circuit 258	5,212	2,335	4,705	5,768	6,021	6,217	6,400	7,579	9,226	10,212
Circuit 259	3,216	2,781	6,168	7,561	7,893	8,150	8,390	8,838	8,838	8,838
Circuit 260	8,148	5,689	4,628	5,673	5,922	6,115	6,294	7,454	9,074	10,044
Circuit 261	4,605	3,914	2,195	2,691	2,809	2,901	2,986	3,536	4,304	4,636
Circuit 262	5,475	4,654	1,483	1,818	1,898	1,960	2,017	2,389	2,812	2,812
Circuit 263	3,763	3,199	2,552	2,552	2,552	2,552	2,552	2,552	2,552	2,552
Circuit 264	5,762	4,898	4,075	4,173	4,173	4,173	4,173	4,173	4,173	4,173
Circuit 265	5,107	3,907	762	934	975	1,007	1,036	1,227	1,494	1,653
Circuit 266	3,937	3,346	182	223	233	240	247	293	357	395
Circuit 267	2,933	2,493	471	578	603	623	641	650	650	650
Circuit 268	6,033	5,128	1,623	1,989	2,077	2,144	2,207	2,614	3,182	3,522
Circuit 269	4,641	3,945	–	–	–	–	–	–	–	–
Circuit 270	4,421	3,758	1,116	1,368	1,428	1,474	1,518	1,797	2,009	2,009
Circuit 271	4,171	3,545	2,511	3,078	3,213	3,317	3,415	4,044	4,577	4,577
Circuit 272	1,154	981	495	607	633	654	673	797	970	1,074
Circuit 273	2,143	1,822	457	561	585	604	622	737	897	973
Circuit 274	2,946	2,504	1,520	1,864	1,946	2,009	2,068	2,449	2,925	2,925
Circuit 275	7,570	5,984	3,619	4,437	4,632	4,782	4,923	4,931	4,931	4,931
Circuit 276	3,122	3,475	4,129	4,129	4,129	4,129	4,129	4,129	4,129	4,129
Circuit 277	4,614	4,103	2,334	2,862	2,987	3,084	3,175	3,760	4,577	5,067
Circuit 278	4,340	3,953	2,186	2,680	2,798	2,888	2,973	3,521	4,286	4,690
Circuit 279	1,177	1,057	986	1,208	1,261	1,302	1,341	1,588	1,933	2,139
Circuit 280	2,936	2,495	897	1,099	1,147	1,185	1,220	1,444	1,758	1,946
Circuit 281	1,316	772	1,169	1,433	1,496	1,545	1,590	1,883	2,032	2,032
Circuit 282	4,214	780	1,137	1,394	1,455	1,502	1,546	1,831	2,229	2,468
Circuit 283	3,839	2,871	1,028	1,260	1,315	1,358	1,398	1,656	2,015	2,231
Circuit 284	2,299	1,954	1,798	2,204	2,300	2,375	2,445	2,895	3,520	3,520
Circuit 285	5,662	1,636	2,961	3,630	3,789	3,912	4,027	4,769	5,806	6,427
Circuit 286	5,271	4,480	33	41	43	44	45	54	66	73
Circuit 287	3,252	2,048	1,978	2,425	2,531	2,614	2,691	3,186	3,399	3,399
Circuit 288	9,600	3,270	3,026	3,709	3,872	3,998	4,115	4,874	5,338	5,338
Circuit 289	2,667	3,617	265	325	339	350	360	427	520	575
Circuit 290	2,772	1,028	1,170	1,434	1,497	1,546	1,592	1,885	2,294	2,540
Circuit 291	4,820	3,749	968	1,187	1,239	1,280	1,317	1,560	1,899	2,102
Circuit 292	5,222	2,086	970	1,189	1,242	1,282	1,320	1,563	1,903	2,106
Circuit 293	5,768	4,903	1,383	1,695	1,769	1,827	1,881	2,227	2,711	3,001

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 294	6,307	3,281	767	940	981	1,013	1,043	1,235	1,503	1,664
Circuit 295	4,017	3,617	328	403	420	434	447	529	644	713
Circuit 296	4,136	2,357	412	505	527	545	561	664	808	895
Circuit 297	3,545	1,694	1,575	1,931	2,015	2,081	2,142	2,537	2,795	2,795
Circuit 298	4,054	3,446	2,444	2,996	3,128	3,230	3,325	3,937	4,507	4,507
Circuit 299	6,304	3,496	844	1,035	1,080	1,115	1,148	1,360	1,655	1,832
Circuit 300	4,455	1,469	1,791	2,195	2,292	2,366	2,436	2,885	3,512	3,887
Circuit 301	1,053	496	484	593	619	639	658	779	948	1,050
Circuit 302	4,019	3,416	1,763	2,161	2,256	2,329	2,397	2,839	3,456	3,825
Circuit 303	6,695	3,596	4,674	5,729	5,981	6,175	6,357	7,528	9,164	9,263
Circuit 304	2,526	2,147	1,365	1,673	1,747	1,798	1,798	1,798	1,798	1,798
Circuit 305	1,852	740	964	1,182	1,234	1,274	1,312	1,553	1,891	2,093
Circuit 306	2,635	1,809	68	83	87	90	92	109	133	147
Circuit 307	4,943	4,202	2,091	2,563	2,676	2,763	2,844	3,368	4,100	4,337
Circuit 308	1,236	1,051	1,080	1,324	1,382	1,427	1,469	1,574	1,574	1,574
Circuit 309	1,140	714	469	575	600	620	638	755	920	928
Circuit 310	6,808	5,787	465	569	594	614	632	748	911	1,008
Circuit 311	6,285	5,342	460	564	589	608	626	741	902	998
Circuit 312	3,034	2,579	–	–	–	–	–	–	–	–
Circuit 313	3,923	2,934	1,799	2,206	2,303	2,377	2,447	2,898	3,484	3,484
Circuit 314	5,183	4,405	1,612	1,976	2,063	2,130	2,192	2,353	2,353	2,353
Circuit 315	3,086	2,623	489	599	626	646	665	788	959	1,061
Circuit 316	1,536	1,305	265	325	339	350	361	427	520	575
Circuit 317	5,006	3,868	48	59	62	64	65	78	94	104
Circuit 318	5,261	3,540	216	265	276	285	294	348	424	469
Circuit 319	4,865	4,135	349	428	447	462	475	563	685	758
Circuit 320	5,762	2,253	2,266	2,778	2,900	2,994	3,082	3,650	4,010	4,010
Circuit 321	337	287	79	96	101	104	107	127	154	171
Circuit 322	4,669	4,724	747	916	956	987	1,016	1,204	1,465	1,620
Circuit 323	144	123	–	–	–	–	–	–	–	–
Circuit 324	5,894	5,010	2,371	2,371	2,371	2,371	2,371	2,371	2,371	2,371
Circuit 325	608	588	501	615	642	662	682	808	983	1,081
Circuit 326	1,410	762	858	1,052	1,098	1,133	1,167	1,382	1,682	1,862
Circuit 327	1,463	511	1,311	1,311	1,311	1,311	1,311	1,311	1,311	1,311
Circuit 328	6,119	5,201	3,099	3,799	3,966	4,095	4,216	4,992	5,819	5,819
Circuit 329	1,610	1,369	1,053	1,290	1,347	1,391	1,432	1,695	2,055	2,055
Circuit 330	5,881	4,999	3,528	4,325	4,515	4,661	4,798	5,127	5,127	5,127
Circuit 331	924	785	95	116	121	125	129	152	186	205

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 332	7,351	3,171	3,679	4,510	4,708	4,861	5,004	5,926	7,214	7,985
Circuit 333	5,964	5,069	1,020	1,250	1,305	1,347	1,387	1,642	1,999	2,213
Circuit 334	2,507	2,131	479	587	613	633	652	772	940	1,040
Circuit 335	3,598	3,058	1,369	1,369	1,369	1,369	1,369	1,369	1,369	1,369
Circuit 336	5,827	4,953	2,046	2,508	2,619	2,704	2,783	2,945	2,945	2,945
Circuit 337	3,697	3,143	1,061	1,301	1,358	1,402	1,444	1,710	2,081	2,304
Circuit 338	959	815	204	204	204	204	204	204	204	204
Circuit 339	9,020	7,667	2,362	2,647	2,647	2,647	2,647	2,647	2,647	2,647
Circuit 340	3,646	3,099	1,452	1,780	1,858	1,918	1,974	2,338	2,846	3,151
Circuit 341	746	634	–	–	–	–	–	–	–	–
Circuit 342	4,140	1,454	1,864	2,286	2,386	2,463	2,536	3,003	3,656	4,046
Circuit 343	5,806	4,935	2,484	3,045	3,178	3,282	3,378	4,001	4,326	4,326
Circuit 344	4,257	3,619	1,738	2,131	2,225	2,297	2,364	2,367	2,367	2,367
Circuit 345	9,447	6,464	738	905	944	975	1,004	1,189	1,447	1,602
Circuit 346	4,257	3,619	1,580	1,937	2,022	2,088	2,150	2,546	3,099	3,251
Circuit 347	6,038	3,233	2,664	3,266	3,409	3,520	3,623	4,291	5,223	5,700
Circuit 348	3,111	1,014	1,179	1,446	1,509	1,558	1,604	1,899	2,312	2,559
Circuit 349	419	356	473	580	605	625	643	761	927	1,026
Circuit 350	6,149	3,240	2,547	3,123	3,260	3,366	3,465	4,103	4,995	5,529
Circuit 351	3,133	2,663	–	–	–	–	–	–	–	–
Circuit 352	2,391	1,567	44	44	44	44	44	44	44	44
Circuit 353	7,969	5,222	–	–	–	–	–	–	–	–
Circuit 354	6,602	5,612	24	29	31	32	33	39	47	52
Circuit 355	6,104	5,188	121	149	155	160	165	195	238	263
Circuit 356	3,888	3,304	46	56	59	61	63	74	90	100
Circuit 357	4,256	3,618	–	–	–	–	–	–	–	–
Circuit 358	2,982	2,535	1,070	1,312	1,369	1,414	1,455	1,724	2,098	2,322
Circuit 359	6,054	949	3,858	4,730	4,937	5,098	5,248	6,214	7,565	8,374
Circuit 360	1,341	513	595	595	595	595	595	595	595	595
Circuit 361	277	122	151	151	151	151	151	151	151	151
Circuit 362	6,306	5,364	1,308	1,604	1,674	1,729	1,780	2,107	2,565	2,840
Circuit 363	4,376	3,725	1,679	2,053	2,053	2,053	2,053	2,053	2,053	2,053
Circuit 364	5,368	4,562	3,881	4,757	4,966	5,127	5,278	6,185	6,185	6,185
Circuit 365	4,712	2,283	1,561	1,914	1,998	2,063	2,124	2,515	3,061	3,388
Circuit 366	4,162	1,910	1,120	1,373	1,434	1,480	1,524	1,805	2,197	2,432
Circuit 367	2,068	1,758	1,173	1,438	1,501	1,550	1,595	1,889	2,299	2,545
Circuit 368	4,623	1,336	1,540	1,887	1,970	2,034	2,094	2,480	3,019	3,342
Circuit 369	5,678	4,380	2,925	3,585	3,743	3,864	3,978	4,711	5,734	6,347

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 370	3,020	524	526	645	674	695	716	848	1,032	1,142
Circuit 371	4,080	913	2,136	2,618	2,733	2,822	2,905	3,440	4,188	4,635
Circuit 372	5,743	4,882	3,688	4,521	4,720	4,873	5,016	5,940	7,138	7,138
Circuit 373	7,141	5,038	4,995	6,123	6,392	6,600	6,794	8,045	8,421	8,421
Circuit 374	4,249	3,612	1,302	1,596	1,666	1,720	1,770	2,096	2,233	2,233
Circuit 375	4,040	3,434	754	924	965	996	1,026	1,215	1,479	1,623
Circuit 376	1,431	1,216	847	1,039	1,084	1,120	1,153	1,208	1,208	1,208
Circuit 377	1,821	717	1,084	1,328	1,387	1,432	1,474	1,745	2,124	2,222
Circuit 378	308	262	37	37	37	37	37	37	37	37
Circuit 379	3,073	2,069	1,454	1,782	1,860	1,921	1,977	2,341	2,850	3,155
Circuit 380	1,552	1,319	1,666	2,042	2,131	2,201	2,265	2,683	2,699	2,699
Circuit 381	1,106	640	907	1,112	1,161	1,199	1,234	1,461	1,779	1,969
Circuit 382	–	–	40,100	49,157	51,315	52,983	54,542	64,588	78,625	87,030

Table N-15. Distribution Circuit Market DG-PV Forecast: Hawaiian Electric (kW)

Hawaiian Electric Distribution Circuit High DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,044	5,137	1,119	1,282	1,402	1,453	1,506	2,547	3,634	3,634
Circuit 2	5,170	2,392	3,308	3,789	4,143	4,294	4,450	6,752	6,752	6,752
Circuit 3	5,692	484	961	1,101	1,203	1,247	1,293	2,186	3,127	3,598
Circuit 4	361	307	–	–	–	–	–	–	–	–
Circuit 5	4,770	3,284	3,163	3,623	3,961	4,106	4,255	7,196	7,987	7,987
Circuit 6	2,556	2,173	383	439	480	497	515	871	1,247	1,434
Circuit 7	1,198	1,019	148	169	185	192	199	336	481	553
Circuit 8	1,940	319	1,020	1,168	1,277	1,324	1,372	2,320	3,320	3,819
Circuit 9	1,301	951	1,041	1,193	1,304	1,352	1,401	2,369	3,389	3,523
Circuit 10	5,107	4,341	2,003	2,295	2,509	2,601	2,695	4,558	6,521	7,502
Circuit 11	689	585	–	–	–	–	–	–	–	–
Circuit 12	1,714	1,457	–	–	–	–	–	–	–	–
Circuit 13	6,272	5,331	154	176	192	199	207	349	500	575
Circuit 14	573	438	635	727	795	825	854	1,445	2,067	2,378
Circuit 15	5,750	4,887	3,480	3,987	4,359	4,519	4,683	7,918	11,328	13,033
Circuit 16	5,701	1,825	2,208	2,529	2,765	2,866	2,970	5,023	7,186	7,297
Circuit 17	5,699	4,605	2,659	3,045	3,330	3,452	3,577	6,049	7,141	7,141
Circuit 18	2,402	2,042	–	–	–	–	–	–	–	–
Circuit 19	3,003	2,553	–	–	–	–	–	–	–	–
Circuit 20	7,330	6,185	529	606	662	687	712	1,203	1,721	1,981
Circuit 21	5,331	4,499	178	204	223	231	239	405	579	667
Circuit 22	4,733	3,901	–	–	–	–	–	–	–	–
Circuit 23	6,741	5,747	1,055	1,208	1,321	1,369	1,419	2,399	3,433	3,950
Circuit 24	1,448	575	840	962	1,051	1,090	1,130	1,910	2,733	2,957
Circuit 25	7,601	4,006	2,933	3,359	3,673	3,808	3,946	6,672	8,143	8,143
Circuit 26	1,005	854	246	282	308	320	331	560	801	922
Circuit 27	771	465	568	651	711	737	764	1,292	1,849	2,127
Circuit 28	4,190	3,686	565	647	708	734	760	1,286	1,839	1,874
Circuit 29	4,187	3,386	3,514	4,026	4,402	4,563	4,728	7,760	7,760	7,760
Circuit 30	6,569	5,583	1,144	1,310	1,433	1,485	1,539	2,603	3,723	4,284
Circuit 31	5,359	4,555	1,151	1,318	1,441	1,494	1,548	2,618	3,029	3,029
Circuit 32	1,211	1,029	457	524	573	594	615	1,040	1,488	1,712
Circuit 33	3,114	1,758	–	–	–	–	–	–	–	–
Circuit 34	3,107	2,641	–	–	–	–	–	–	–	–
Circuit 35	6,611	5,619	2,025	2,319	2,536	2,629	2,724	4,006	4,006	4,006
Circuit 36	4,151	3,635	208	239	261	270	280	474	678	780

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	2,806	2,385	–	–	–	–	–	–	–	–
Circuit 38	4,488	3,737	273	313	342	354	367	621	888	1,022
Circuit 39	1,403	1,193	–	–	–	–	–	–	–	–
Circuit 40	1,873	249	1,865	2,137	2,336	2,422	2,510	4,137	4,137	4,137
Circuit 41	3,266	2,252	312	357	391	405	420	710	1,016	1,169
Circuit 42	3,126	2,657	–	–	–	–	–	–	–	–
Circuit 43	4,186	3,558	520	596	651	675	700	1,183	1,410	1,410
Circuit 44	5,293	1,234	283	324	354	367	380	643	920	1,059
Circuit 45	5,673	4,822	2,476	2,476	2,476	2,476	2,476	2,476	2,476	2,476
Circuit 46	1,380	1,161	1,074	1,230	1,345	1,394	1,445	2,443	3,130	3,130
Circuit 47	3,559	3,025	–	–	–	–	–	–	–	–
Circuit 48	4,529	3,850	–	–	–	–	–	–	–	–
Circuit 49	3,102	2,637	3,117	3,571	3,905	4,047	4,194	6,801	6,801	6,801
Circuit 50	5,323	4,426	2,909	3,332	3,643	3,777	3,914	6,618	7,377	7,377
Circuit 51	3,931	3,126	1,844	2,112	2,309	2,394	2,481	4,195	6,001	6,904
Circuit 52	4,736	2,867	2,292	2,625	2,870	2,975	3,083	5,214	7,459	7,938
Circuit 53	5,383	6,171	3,342	3,828	4,186	4,339	4,497	7,604	9,635	9,635
Circuit 54	4,830	4,355	3,074	3,521	3,850	3,991	4,135	5,335	5,335	5,335
Circuit 55	6,640	5,120	2,810	2,810	2,810	2,810	2,810	2,810	2,810	2,810
Circuit 56	2,289	1,001	763	873	955	990	1,026	1,735	2,482	2,856
Circuit 57	5,837	3,689	748	857	937	972	1,007	1,703	2,436	2,451
Circuit 58	3,014	2,562	4	4	5	5	5	8	12	14
Circuit 59	6,331	3,121	246	281	308	319	331	559	564	564
Circuit 60	3,667	3,117	338	387	424	439	455	769	1,101	1,267
Circuit 61	2,895	2,461	190	218	238	247	256	432	618	712
Circuit 62	4,599	4,180	2,446	2,446	2,446	2,446	2,446	2,446	2,446	2,446
Circuit 63	4,789	4,544	2,668	3,056	3,342	3,464	3,590	6,070	7,046	7,046
Circuit 64	4,747	4,445	4,837	5,541	6,058	6,280	6,508	7,472	7,472	7,472
Circuit 65	3,651	3,341	1,534	1,757	1,921	1,991	2,063	3,489	3,999	3,999
Circuit 66	3,366	2,861	1,786	2,046	2,237	2,318	2,403	4,063	4,962	4,962
Circuit 67	4,703	3,402	2,370	2,715	2,969	3,077	3,189	3,347	3,347	3,347
Circuit 68	4,308	3,662	1,984	2,273	2,485	2,576	2,670	4,515	4,895	4,895
Circuit 69	5,586	4,100	2,163	2,478	2,709	2,808	2,910	4,921	7,040	7,348
Circuit 70	4,351	3,698	1,461	1,674	1,830	1,897	1,966	3,324	4,756	5,472
Circuit 71	8,420	7,157	3,285	3,763	4,115	4,265	4,420	7,474	10,693	12,302
Circuit 72	930	506	8	9	10	11	11	19	27	31
Circuit 73	5,289	4,496	2,955	3,384	3,701	3,836	3,975	6,722	8,100	8,100
Circuit 74	6,899	841	1,018	1,166	1,275	1,322	1,370	2,316	3,313	3,812

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	7,393	4,965	160	183	200	207	215	363	519	597
Circuit 76	3,528	2,999	–	–	–	–	–	–	–	–
Circuit 77	2,673	2,594	52	60	65	67	70	118	169	195
Circuit 78	7,301	1,140	3,048	3,492	3,818	3,958	4,101	6,935	7,400	7,400
Circuit 79	1,470	706	1,894	2,170	2,372	2,459	2,548	3,241	3,241	3,241
Circuit 80	5,814	3,867	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640
Circuit 81	5,352	3,730	2,687	3,078	3,366	3,489	3,616	6,114	8,182	8,182
Circuit 82	220	445	136	156	171	177	183	310	444	510
Circuit 83	1,968	1,673	904	1,036	1,132	1,174	1,216	2,057	2,060	2,060
Circuit 84	3,688	3,134	1,863	2,134	2,334	2,419	2,507	4,239	4,769	4,769
Circuit 85	5,288	4,495	1,168	1,338	1,463	1,516	1,571	2,657	3,801	4,041
Circuit 86	6,597	5,607	941	1,078	1,178	1,222	1,266	1,793	1,793	1,793
Circuit 87	5,113	5,647	2,759	3,160	3,455	3,582	3,712	6,223	6,223	6,223
Circuit 88	2,363	1,839	711	815	891	924	957	1,619	2,060	2,060
Circuit 89	2,488	2,419	1,052	1,205	1,318	1,366	1,416	2,394	2,895	2,895
Circuit 90	5,510	4,684	658	753	824	854	885	1,496	2,141	2,463
Circuit 91	1,351	474	593	680	743	770	798	1,350	1,932	2,222
Circuit 92	3,605	3,064	–	–	–	–	–	–	–	–
Circuit 93	2,416	1,356	1,537	1,760	1,925	1,995	2,068	3,496	3,706	3,706
Circuit 94	4,283	3,640	6	7	8	8	8	14	20	22
Circuit 95	6,936	5,896	3,372	3,372	3,372	3,372	3,372	3,372	3,372	3,372
Circuit 96	7,190	6,112	506	579	634	657	681	1,151	1,647	1,894
Circuit 97	7,570	6,435	–	–	–	–	–	–	–	–
Circuit 98	3,979	3,382	291	334	365	378	392	566	566	566
Circuit 99	13,437	10,102	–	–	–	–	–	–	–	–
Circuit 100	4,164	3,539	–	–	–	–	–	–	–	–
Circuit 101	4,381	3,724	3,140	3,597	3,933	4,077	4,225	7,144	7,992	7,992
Circuit 102	4,691	1,374	1,719	1,719	1,719	1,719	1,719	1,719	1,719	1,719
Circuit 103	6,866	5,836	1,490	1,707	1,866	1,934	2,005	3,390	3,772	3,772
Circuit 104	2,085	1,079	1,324	1,516	1,658	1,719	1,781	3,012	4,309	4,957
Circuit 105	1,609	1,367	891	1,021	1,116	1,157	1,199	2,028	2,901	3,023
Circuit 106	6,462	2,525	1,555	1,781	1,947	2,018	2,092	3,537	5,060	5,411
Circuit 107	1,905	816	1,225	1,404	1,535	1,591	1,649	2,788	3,628	3,628
Circuit 108	5,240	3,794	2,262	2,591	2,833	2,937	3,043	5,146	7,362	7,598
Circuit 109	4,903	1,667	1,747	2,002	2,188	2,269	2,351	3,975	5,687	6,202
Circuit 110	349	296	330	378	413	428	443	750	1,073	1,234
Circuit 111	1,287	678	782	895	979	1,015	1,052	1,779	2,545	2,889
Circuit 112	3,746	3,184	2,622	3,004	3,284	3,404	3,528	5,543	5,543	5,543

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 113	7,039	5,983	4,665	5,344	5,843	6,057	6,277	9,526	9,526	9,526
Circuit 114	5,755	4,892	3,272	3,748	4,098	4,248	4,403	7,444	9,977	9,977
Circuit 115	1,862	890	1,991	2,280	2,493	2,584	2,678	4,474	4,474	4,474
Circuit 116	1,393	697	905	1,037	1,134	1,175	1,218	2,059	2,946	3,325
Circuit 117	2,519	765	429	491	537	557	577	976	1,396	1,606
Circuit 118	430	700	6	7	8	8	9	14	21	24
Circuit 119	2,006	1,399	–	–	–	–	–	–	–	–
Circuit 120	4,969	3,214	320	367	401	416	431	728	1,042	1,199
Circuit 121	8,943	6,377	378	433	473	491	508	860	958	958
Circuit 122	2,169	1,102	873	1,000	1,093	1,133	1,174	1,985	2,840	3,268
Circuit 123	2,344	1,992	241	276	302	313	324	548	784	903
Circuit 124	4,831	4,107	–	–	–	–	–	–	–	–
Circuit 125	1,435	1,086	1,671	1,914	2,093	2,170	2,248	2,895	2,895	2,895
Circuit 126	6,644	4,806	–	–	–	–	–	–	–	–
Circuit 127	5,187	4,409	–	–	–	–	–	–	–	–
Circuit 128	1,604	1,364	415	476	520	539	559	945	1,352	1,556
Circuit 129	1,681	916	666	763	834	864	896	1,515	2,167	2,493
Circuit 130	1,352	1,086	343	393	430	445	462	780	1,116	1,285
Circuit 131	2,267	1,446	748	857	937	971	1,006	1,701	2,434	2,800
Circuit 132	2,449	2,082	518	593	649	673	697	1,179	1,464	1,464
Circuit 133	5,337	4,536	1,058	1,212	1,326	1,374	1,424	2,408	3,445	3,508
Circuit 134	2,267	1,002	911	1,044	1,141	1,183	1,226	2,073	2,966	3,412
Circuit 135	2,752	515	1,026	1,176	1,285	1,332	1,381	2,335	3,341	3,843
Circuit 136	4,602	2,088	600	687	752	779	807	–	–	–
Circuit 137	1,505	1,809	8	9	10	10	11	18	26	30
Circuit 138	5,753	5,889	1,214	1,391	1,521	1,576	1,634	2,762	3,682	3,682
Circuit 139	3,459	2,468	3,029	3,469	3,793	3,932	4,075	6,063	6,063	6,063
Circuit 140	3,856	3,863	773	886	969	1,004	1,041	1,760	2,517	2,896
Circuit 141	2,659	1,905	1,736	1,988	2,174	2,253	2,335	3,949	5,649	6,500
Circuit 142	2,792	2,539	998	1,143	1,250	1,296	1,343	1,467	1,467	1,467
Circuit 143	1,889	1,583	1,488	1,705	1,733	1,733	1,733	1,733	1,733	1,733
Circuit 144	8,363	7,109	600	687	752	779	807	1,365	1,953	2,247
Circuit 145	6,223	5,290	300	344	376	390	404	683	976	1,123
Circuit 146	6,528	5,549	2,207	2,528	2,765	2,866	2,970	5,022	6,797	6,797
Circuit 147	3,308	2,812	132	151	166	172	178	301	430	495
Circuit 148	2,783	2,366	1,694	1,940	2,121	2,199	2,279	3,854	5,513	5,727
Circuit 149	6,292	5,081	569	651	712	738	765	1,294	1,851	2,129
Circuit 150	2,983	2,028	272	312	341	354	366	470	470	470

N. Integrating DG-PV on Our Circuits

DG-PV Forecasts by Distribution Circuit

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 151	5,020	4,267	2,519	2,886	3,155	3,270	3,389	5,731	6,082	6,082
Circuit 152	5,741	3,499	587	672	735	762	789	1,335	1,910	2,197
Circuit 153	4,106	2,067	232	265	290	301	312	527	754	867
Circuit 154	4,941	1,152	–	–	–	–	–	–	–	–
Circuit 155	5,774	4,908	–	–	–	–	–	–	–	–
Circuit 156	4,879	4,147	–	–	–	–	–	–	–	–
Circuit 157	3,629	3,084	87	87	87	87	87	87	87	87
Circuit 158	889	499	316	362	395	410	425	718	1,028	1,182
Circuit 159	2,132	984	589	675	738	765	792	1,340	1,917	2,206
Circuit 160	5,736	4,137	535	613	670	694	720	1,217	1,741	2,003
Circuit 161	6,310	4,551	1,246	1,427	1,560	1,617	1,676	2,834	3,989	3,989
Circuit 162	4,056	3,448	364	416	455	472	489	827	1,159	1,159
Circuit 163	1,911	1,624	206	208	208	208	208	208	208	208
Circuit 164	725	920	629	720	788	816	846	1,431	1,467	1,467
Circuit 165	1,877	1,595	–	–	–	–	–	–	–	–
Circuit 166	1,032	877	398	455	498	516	535	904	1,294	1,489
Circuit 167	5,120	4,352	578	662	724	750	778	1,315	1,881	2,165
Circuit 168	3,546	963	1,226	1,404	1,535	1,592	1,649	2,789	3,990	4,591
Circuit 169	4,029	2,935	3,628	4,156	4,544	4,710	4,882	5,088	5,088	5,088
Circuit 170	1,120	952	409	469	513	532	551	932	1,333	1,533
Circuit 171	4,969	3,827	248	284	311	322	334	565	808	930
Circuit 172	2,755	2,342	362	414	453	469	487	823	1,177	1,354
Circuit 173	624	531	442	506	554	574	595	1,006	1,439	1,469
Circuit 174	3,230	2,745	928	1,063	1,162	1,205	1,248	2,111	3,001	3,001
Circuit 175	7,927	5,784	692	792	866	898	930	1,573	2,251	2,590
Circuit 176	721	613	–	–	–	–	–	–	–	–
Circuit 177	4,497	3,822	1,617	1,852	2,025	2,099	2,175	3,679	4,211	4,211
Circuit 178	7,024	6,024	1,275	1,460	1,596	1,655	1,715	2,900	3,764	3,764
Circuit 179	3,851	3,052	115	131	144	149	154	261	373	429
Circuit 180	5,782	4,088	83	95	104	108	111	188	270	310
Circuit 181	83	62	–	–	–	–	–	–	–	–
Circuit 182	3,416	2,510	116	133	145	150	156	263	377	433
Circuit 183	11,185	9,507	500	573	626	649	673	1,138	1,627	1,872
Circuit 184	5,907	5,021	270	309	338	351	363	614	879	1,011
Circuit 185	6,299	5,354	1,945	2,228	2,436	2,525	2,617	4,425	5,022	5,022
Circuit 186	1,088	707	957	1,097	1,199	1,243	1,288	2,178	3,116	3,534
Circuit 187	3,487	2,964	355	407	445	461	478	808	1,156	1,330
Circuit 188	6,420	5,641	282	323	354	367	380	642	919	1,057

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 189	60	52	–	–	–	–	–	–	–	–
Circuit 190	4,546	3,864	–	–	–	–	–	–	–	–
Circuit 191	3,108	2,642	2,350	2,692	2,944	3,052	3,162	5,347	5,473	5,473
Circuit 192	1,030	450	635	727	795	824	854	1,444	2,065	2,376
Circuit 193	3,249	759	–	–	–	–	–	–	–	–
Circuit 194	4,897	4,163	1,897	2,173	2,376	2,462	2,552	4,315	4,339	4,339
Circuit 195	4,138	3,518	1,373	1,573	1,720	1,783	1,848	2,547	2,547	2,547
Circuit 196	7,671	6,520	2,649	3,034	3,318	3,439	3,564	6,026	8,157	8,157
Circuit 197	10,634	9,039	4,440	5,087	5,562	5,765	5,975	9,517	9,517	9,517
Circuit 198	952	809	203	232	254	263	268	268	268	268
Circuit 199	4,410	3,749	1,676	1,920	2,099	2,176	2,255	3,813	4,618	4,618
Circuit 200	4,112	1,608	1,137	1,303	1,425	1,477	1,530	2,588	3,400	3,400
Circuit 201	4,019	3,416	2,551	2,922	3,195	3,312	3,432	5,804	6,161	6,161
Circuit 202	4,355	2,666	1,694	1,941	2,122	2,199	2,279	3,854	3,897	3,897
Circuit 203	505	430	87	100	109	113	117	144	144	144
Circuit 204	5,370	4,565	39	44	48	50	52	88	126	144
Circuit 205	983	835	–	–	–	–	–	–	–	–
Circuit 206	3,562	3,027	–	–	–	–	–	–	–	–
Circuit 207	4,274	3,083	58	66	72	75	78	131	188	216
Circuit 208	3,627	1,295	836	957	1,046	1,085	1,124	1,901	2,720	3,129
Circuit 209	1,711	1,454	545	624	683	708	733	1,240	1,774	2,041
Circuit 210	3,125	2,693	1,537	1,761	1,925	1,995	2,068	3,497	5,003	5,078
Circuit 211	6,616	5,808	3,213	3,680	4,024	4,171	4,323	7,310	9,474	9,474
Circuit 212	5,706	5,033	2,562	2,935	3,209	3,327	3,448	5,830	7,214	7,214
Circuit 213	1,903	1,471	1,139	1,304	1,426	1,478	1,532	2,591	3,706	4,113
Circuit 214	8,176	6,950	350	401	438	454	471	796	1,139	1,311
Circuit 215	5,354	3,717	1,590	1,821	1,992	2,064	2,139	3,618	4,244	4,244
Circuit 216	2,008	1,706	609	697	762	790	819	1,385	1,464	1,464
Circuit 217	5,447	4,630	1,120	1,283	1,403	1,454	1,464	1,464	1,464	1,464
Circuit 218	3,541	3,010	1,371	1,570	1,717	1,780	1,845	3,119	4,462	4,877
Circuit 219	179	152	–	–	–	–	–	–	–	–
Circuit 220	2,869	2,438	1,993	2,283	2,497	2,588	2,682	4,535	6,316	6,316
Circuit 221	6,009	4,641	1,722	1,973	2,157	2,236	2,317	3,918	5,606	5,659
Circuit 222	2,079	1,767	1,602	1,835	2,006	2,080	2,155	3,645	4,802	4,802
Circuit 223	5,005	2,998	907	1,039	1,136	1,177	1,220	2,063	2,952	3,163
Circuit 224	2,919	2,127	350	401	438	454	471	796	1,029	1,029
Circuit 225	8,145	6,776	863	989	1,081	1,121	1,162	1,964	2,810	3,233
Circuit 226	1,186	578	322	369	404	419	434	734	1,050	1,207

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 227	190	162	35	40	43	45	47	79	88	88
Circuit 228	2,419	676	917	1,050	1,148	1,190	1,233	2,086	2,984	3,433
Circuit 229	7,351	6,249	2,573	2,948	3,223	3,341	3,462	5,854	6,995	6,995
Circuit 230	4,579	3,892	1,027	1,177	1,287	1,334	1,382	2,337	3,344	3,847
Circuit 231	2,090	1,777	599	686	751	778	806	1,363	1,951	2,244
Circuit 232	4,899	4,237	96	110	120	125	129	218	312	360
Circuit 233	7,858	4,263	2,930	3,356	3,669	3,804	3,942	6,665	8,207	8,207
Circuit 234	1,663	1,532	294	337	369	382	396	669	679	679
Circuit 235	5,011	4,027	2,338	2,679	2,929	3,036	3,146	4,380	4,380	4,380
Circuit 236	8,704	4,964	3,984	4,564	4,990	5,172	5,360	8,657	8,657	8,657
Circuit 237	4,312	4,027	2,592	2,969	3,246	3,365	3,487	5,896	7,079	7,079
Circuit 238	748	717	958	1,097	1,199	1,243	1,288	2,179	2,328	2,328
Circuit 239	3,566	3,031	1,897	2,173	2,376	2,463	2,553	4,316	6,175	7,061
Circuit 240	4,602	4,036	2	3	3	3	3	6	8	9
Circuit 241	8,243	6,839	2,600	2,978	3,256	3,376	3,498	3,515	3,515	3,515
Circuit 242	1,597	1,256	365	418	457	474	491	830	1,188	1,366
Circuit 243	177	2,344	–	–	–	–	–	–	–	–
Circuit 244	2,979	3,794	679	777	850	881	913	1,544	2,209	2,541
Circuit 245	5,261	3,543	2,168	2,484	2,716	2,815	2,917	4,933	5,756	5,756
Circuit 246	711	226	–	–	–	–	–	–	–	–
Circuit 247	4,259	3,857	438	502	548	568	589	996	1,425	1,640
Circuit 248	4,452	793	1,099	1,259	1,376	1,426	1,478	2,500	3,410	3,410
Circuit 249	3,632	432	228	261	286	296	307	519	743	855
Circuit 250	2,345	1,993	1,140	1,306	1,428	1,480	1,534	2,593	3,630	3,630
Circuit 251	8,975	5,107	8,105	9,284	10,152	10,413	10,413	10,413	10,413	10,413
Circuit 252	2,897	963	1,507	1,726	1,887	1,956	2,027	3,428	4,128	4,128
Circuit 253	108	92	–	–	–	–	–	–	–	–
Circuit 254	7,195	6,288	585	670	733	759	787	1,331	1,776	1,776
Circuit 255	5,548	5,328	536	614	672	696	722	1,220	1,740	1,740
Circuit 256	3,836	3,624	726	832	910	943	977	1,653	1,989	1,989
Circuit 257	5,354	5,059	1,474	1,688	1,846	1,914	1,983	3,353	4,798	5,520
Circuit 258	5,212	2,335	4,705	5,390	5,893	6,109	6,331	8,958	8,958	8,958
Circuit 259	3,216	2,781	6,168	6,253	6,253	6,253	6,253	6,253	6,253	6,253
Circuit 260	8,148	5,689	4,628	5,301	5,796	6,009	6,227	10,529	13,715	13,715
Circuit 261	4,605	3,914	2,195	2,515	2,750	2,850	2,954	4,995	6,101	6,101
Circuit 262	5,475	4,654	1,483	1,699	1,858	1,926	1,996	3,375	4,276	4,276
Circuit 263	3,763	3,199	2,552	2,923	3,196	3,271	3,271	3,271	3,271	3,271
Circuit 264	5,762	4,898	4,075	4,668	5,104	5,291	5,483	5,637	5,637	5,637

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 265	5,107	3,907	762	873	954	989	1,025	1,733	1,925	1,925
Circuit 266	3,937	3,346	182	208	228	236	245	414	592	681
Circuit 267	2,933	2,493	471	540	590	612	634	650	650	650
Circuit 268	6,033	5,128	1,623	1,859	2,033	2,107	2,184	3,692	5,283	5,706
Circuit 269	4,641	3,945	–	–	–	–	–	–	–	–
Circuit 270	4,421	3,758	1,116	1,278	1,398	1,449	1,501	2,539	3,098	3,098
Circuit 271	4,171	3,545	2,511	2,876	3,144	3,260	3,378	5,712	6,041	6,041
Circuit 272	1,154	981	495	567	620	643	666	1,126	1,611	1,853
Circuit 273	2,143	1,822	457	524	573	594	615	1,041	1,489	1,713
Circuit 274	2,946	2,504	1,520	1,742	1,904	1,974	2,046	3,459	4,389	4,389
Circuit 275	7,570	5,984	3,619	4,146	4,533	4,699	4,870	6,395	6,395	6,395
Circuit 276	3,122	3,475	4,129	4,129	4,129	4,129	4,129	4,129	4,129	4,129
Circuit 277	4,614	4,103	2,334	2,674	2,924	3,031	3,141	5,311	6,926	6,926
Circuit 278	4,340	3,953	2,186	2,504	2,738	2,838	2,941	4,974	6,154	6,154
Circuit 279	1,177	1,057	986	1,129	1,235	1,280	1,326	1,798	1,798	1,798
Circuit 280	2,936	2,495	897	1,027	1,123	1,164	1,206	2,040	2,919	3,358
Circuit 281	1,316	772	1,169	1,339	1,464	1,518	1,573	2,660	3,496	3,496
Circuit 282	4,214	780	1,137	1,302	1,424	1,476	1,530	2,587	3,701	4,258
Circuit 283	3,839	2,871	1,028	1,177	1,287	1,335	1,383	2,339	3,346	3,849
Circuit 284	2,299	1,954	1,798	2,059	2,251	2,334	2,419	4,090	4,985	4,985
Circuit 285	5,662	1,636	2,961	3,392	3,709	3,845	3,984	6,737	7,920	7,920
Circuit 286	5,271	4,480	33	38	42	43	45	76	109	125
Circuit 287	3,252	2,048	1,978	2,266	2,478	2,568	2,662	4,501	4,863	4,863
Circuit 288	9,600	3,270	3,026	3,466	3,790	3,928	4,071	6,802	6,802	6,802
Circuit 289	2,667	3,617	265	304	332	344	357	603	862	992
Circuit 290	2,772	1,028	1,170	1,340	1,464	1,464	1,464	1,464	1,464	1,464
Circuit 291	4,820	3,749	968	1,109	1,213	1,257	1,303	2,203	3,152	3,627
Circuit 292	5,222	2,086	970	1,112	1,215	1,260	1,306	2,208	3,111	3,111
Circuit 293	5,768	4,903	1,383	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Circuit 294	6,307	3,281	767	878	960	996	1,032	1,745	2,496	2,871
Circuit 295	4,017	3,617	328	376	411	426	442	747	903	903
Circuit 296	4,136	2,357	412	472	516	535	555	938	1,342	1,361
Circuit 297	3,545	1,694	1,575	1,804	1,973	2,045	2,119	3,583	4,239	4,239
Circuit 298	4,054	3,446	2,444	2,800	3,062	3,174	3,289	5,561	5,972	5,972
Circuit 299	6,304	3,496	844	967	1,057	1,096	1,136	1,921	2,748	3,162
Circuit 300	4,455	1,469	1,791	2,052	2,243	2,325	2,410	4,075	5,830	6,707
Circuit 301	1,053	496	484	554	606	628	651	1,100	1,574	1,811
Circuit 302	4,019	3,416	1,763	2,019	2,208	2,288	2,372	4,010	5,737	5,758

DG-PV Forecasts by Distribution Circuit

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 303	6,695	3,596	4,674	5,354	5,854	6,068	6,289	10,430	10,430	10,430
Circuit 304	2,526	2,147	1,365	1,564	1,710	1,772	1,837	2,893	2,893	2,893
Circuit 305	1,852	740	964	1,105	1,208	1,252	1,298	2,194	3,139	3,611
Circuit 306	2,635	1,809	68	78	85	88	91	155	221	254
Circuit 307	4,943	4,202	2,091	2,395	2,619	2,715	2,813	4,757	5,801	5,801
Circuit 308	1,236	1,051	1,080	1,237	1,352	1,402	1,453	2,457	3,039	3,039
Circuit 309	1,140	714	469	537	587	609	631	1,067	1,527	1,757
Circuit 310	6,808	5,787	465	532	582	603	625	1,057	1,512	1,740
Circuit 311	6,285	5,342	460	527	576	597	619	1,047	1,497	1,723
Circuit 312	3,034	2,579	–	–	–	–	–	–	–	–
Circuit 313	3,923	2,934	1,799	2,061	2,254	2,336	2,421	4,094	4,949	4,949
Circuit 314	5,183	4,405	1,612	1,846	2,019	2,093	2,169	3,667	3,805	3,805
Circuit 315	3,086	2,623	489	560	612	635	658	1,112	1,591	1,831
Circuit 316	1,536	1,305	265	304	332	344	357	603	731	731
Circuit 317	5,006	3,868	48	55	60	62	65	109	157	180
Circuit 318	5,261	3,540	216	247	271	280	291	491	703	809
Circuit 319	4,865	4,135	349	400	438	454	470	795	1,137	1,308
Circuit 320	5,762	2,253	2,266	2,596	2,838	2,942	3,049	5,155	5,474	5,474
Circuit 321	337	287	79	90	99	102	106	179	256	295
Circuit 322	4,669	4,724	747	856	936	970	1,005	1,620	1,620	1,620
Circuit 323	144	123	–	–	–	–	–	–	–	–
Circuit 324	5,894	5,010	2,371	2,716	2,970	3,079	3,190	3,581	3,581	3,581
Circuit 325	608	588	501	574	628	651	675	1,141	1,632	1,878
Circuit 326	1,410	762	858	983	1,074	1,114	1,154	1,952	2,792	3,212
Circuit 327	1,463	511	1,311	1,502	1,511	1,511	1,511	1,511	1,511	1,511
Circuit 328	6,119	5,201	3,099	3,550	3,882	4,024	4,170	7,051	7,283	7,283
Circuit 329	1,610	1,369	1,053	1,206	1,318	1,367	1,416	2,395	3,426	3,519
Circuit 330	5,881	4,999	3,528	4,041	4,419	4,580	4,747	6,592	6,592	6,592
Circuit 331	924	785	95	108	119	123	127	215	308	355
Circuit 332	7,351	3,171	3,679	4,215	4,608	4,777	4,951	8,371	10,701	10,701
Circuit 333	5,964	5,069	1,020	1,168	1,277	1,324	1,372	2,320	3,319	3,818
Circuit 334	2,507	2,131	479	549	600	622	645	1,090	1,560	1,795
Circuit 335	3,598	3,058	1,369	1,568	1,714	1,777	1,842	2,649	2,649	2,649
Circuit 336	5,827	4,953	2,046	2,344	2,563	2,657	2,753	4,210	4,210	4,210
Circuit 337	3,697	3,143	1,061	1,216	1,329	1,378	1,428	2,415	3,455	3,975
Circuit 338	959	815	204	233	255	264	274	463	663	762
Circuit 339	9,020	7,667	2,362	2,705	2,958	3,066	3,178	4,111	4,111	4,111
Circuit 340	3,646	3,099	1,452	1,663	1,818	1,885	1,953	3,303	4,675	4,675

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 341	746	634	–	–	–	–	–	–	–	–
Circuit 342	4,140	1,454	1,864	2,136	2,335	2,421	2,509	4,242	6,069	6,982
Circuit 343	5,806	4,935	2,484	2,845	3,111	3,225	3,342	5,651	5,760	5,760
Circuit 344	4,257	3,619	1,738	1,991	2,177	2,257	2,339	3,468	3,468	3,468
Circuit 345	9,447	6,464	738	845	924	958	993	1,679	2,402	2,764
Circuit 346	4,257	3,619	1,580	1,810	1,979	2,052	2,126	3,596	4,565	4,565
Circuit 347	6,038	3,233	2,664	3,052	3,337	3,459	3,584	6,061	7,164	7,164
Circuit 348	3,111	1,014	1,179	1,351	1,477	1,531	1,587	2,683	3,838	4,416
Circuit 349	419	356	473	542	592	614	636	1,076	1,539	1,770
Circuit 350	6,149	3,240	2,547	2,918	3,191	3,307	3,428	5,796	7,505	7,505
Circuit 351	3,133	2,663	–	–	–	–	–	–	–	–
Circuit 352	2,391	1,567	44	44	44	44	44	44	44	44
Circuit 353	7,969	5,222	–	–	–	–	–	–	–	–
Circuit 354	6,602	5,612	24	27	30	31	32	55	78	90
Circuit 355	6,104	5,188	121	139	152	157	163	276	395	454
Circuit 356	3,888	3,304	46	53	58	60	62	105	150	172
Circuit 357	4,256	3,618	–	–	–	–	–	–	–	–
Circuit 358	2,982	2,535	1,070	1,226	1,340	1,389	1,440	2,435	3,483	3,940
Circuit 359	6,054	949	3,858	4,420	4,833	5,009	5,191	8,778	11,248	11,248
Circuit 360	1,341	513	595	682	746	773	801	1,355	1,464	1,464
Circuit 361	277	122	151	173	189	196	203	343	491	565
Circuit 362	6,306	5,364	1,308	1,499	1,639	1,699	1,761	2,977	4,259	4,433
Circuit 363	4,376	3,725	1,679	1,923	2,103	2,180	2,259	3,517	3,517	3,517
Circuit 364	5,368	4,562	3,881	4,445	4,861	5,038	5,221	7,650	7,650	7,650
Circuit 365	4,712	2,283	1,561	1,788	1,956	2,027	2,101	3,552	5,003	5,003
Circuit 366	4,162	1,910	1,120	1,283	1,403	1,455	1,507	2,549	3,647	4,196
Circuit 367	2,068	1,758	1,173	1,343	1,469	1,523	1,578	2,668	3,817	4,392
Circuit 368	4,623	1,336	1,540	1,764	1,929	1,999	2,072	3,503	5,012	5,766
Circuit 369	5,678	4,380	2,925	3,350	3,663	3,797	3,935	6,654	9,264	9,264
Circuit 370	3,020	524	526	603	659	683	708	1,198	1,713	1,971
Circuit 371	4,080	913	2,136	2,447	2,675	2,773	2,874	4,859	6,938	6,938
Circuit 372	5,743	4,882	3,688	4,225	4,620	4,789	4,962	8,391	8,592	8,592
Circuit 373	7,141	5,038	4,995	5,722	6,256	6,485	6,721	9,886	9,886	9,886
Circuit 374	4,249	3,612	1,302	1,491	1,630	1,690	1,751	2,961	3,670	3,670
Circuit 375	4,040	3,434	754	864	945	979	1,015	1,716	2,455	2,824
Circuit 376	1,431	1,216	847	971	1,061	1,100	1,140	1,928	2,223	2,223
Circuit 377	1,821	717	1,084	1,241	1,357	1,407	1,458	2,465	3,527	3,686
Circuit 378	308	262	37	42	46	47	49	83	119	137

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 379	3,073	2,069	1,454	1,665	1,821	1,887	1,956	3,307	4,732	5,216
Circuit 380	1,552	1,319	1,666	1,908	2,086	2,163	2,241	3,789	4,163	4,163
Circuit 381	1,106	640	907	1,039	1,136	1,178	1,221	2,064	2,953	3,398
Circuit 382	–	–	24,363	40,100	81,458	122,815	164,173	381,960	381,960	381,960

Table N-16. Distribution Circuit High DG-PV Forecast: Hawaiian Electric (kW)

Maui Electric Distribution Circuit Market DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	3,302	2,871	2,476	2,845	2,845	2,845	2,845	2,845	2,845	2,845
Circuit 2	1,233	1,072	852	873	873	873	873	873	873	873
Circuit 3	166	145	170	170	170	170	170	170	170	170
Circuit 4	22	19	32	32	32	32	32	32	32	32
Circuit 5	29	26	48	56	57	57	58	60	63	65
Circuit 6	188	163	215	215	215	215	215	215	215	215
Circuit 7	3,192	2,776	948	1,018	1,018	1,018	1,018	1,018	1,018	1,018
Circuit 8	3,602	3,132	3,063	3,536	3,592	3,592	3,592	3,592	3,592	3,592
Circuit 9	473	411	1,118	1,291	1,312	1,326	1,339	1,383	1,452	1,452
Circuit 10	330	287	998	1,033	1,033	1,033	1,033	1,033	1,033	1,033
Circuit 11	283	246	436	486	486	486	486	486	486	486
Circuit 12	77	67	9	9	9	9	9	9	9	9
Circuit 13	–	–	166	166	166	166	166	166	166	166
Circuit 14	5,807	5,049	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452
Circuit 15	2,141	1,862	823	823	823	823	823	823	823	823
Circuit 16	5,115	4,448	2,065	2,384	2,423	2,449	2,472	2,554	2,698	2,698
Circuit 17	4,569	3,973	2,163	2,497	2,537	2,565	2,589	2,675	2,835	2,891
Circuit 18	6,033	5,246	1,447	1,670	1,697	1,715	1,732	1,789	1,896	1,985
Circuit 19	8,174	7,108	7,963	7,963	7,963	7,963	7,963	7,963	7,963	7,963
Circuit 20	1,117	971	850	895	895	895	895	895	895	895
Circuit 21	199	173	31	35	36	36	37	38	40	42
Circuit 22	5,168	4,494	2,111	2,111	2,111	2,111	2,111	2,111	2,111	2,111
Circuit 23	5,963	5,185	3,213	3,680	3,680	3,680	3,680	3,680	3,680	3,680
Circuit 24	1,133	985	3,885	4,485	4,557	4,607	4,650	4,805	4,929	4,929
Circuit 25	1,806	1,570	4,492	5,186	5,269	5,327	5,377	5,556	5,559	5,559
Circuit 26	629	547	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Circuit 27	7,439	6,469	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
Circuit 28	539	469	571	659	670	677	684	690	690	690
Circuit 29	2,599	2,260	3,115	3,596	3,654	3,694	3,728	3,829	3,829	3,829
Circuit 30	2,103	1,829	2,901	3,350	3,398	3,398	3,398	3,398	3,398	3,398
Circuit 31	153	133	553	608	608	608	608	608	608	608
Circuit 32	6,784	5,899	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717
Circuit 33	3,009	2,616	2,734	3,157	3,207	3,242	3,273	3,382	3,477	3,477
Circuit 34	2,091	1,818	589	680	691	697	697	697	697	697
Circuit 35	2,003	1,742	189	219	222	225	227	234	248	260
Circuit 36	2,361	2,053	3,066	3,445	3,445	3,445	3,445	3,445	3,445	3,445

DG-PV Forecasts by Distribution Circuit

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	1,728	1,502	245	245	245	245	245	245	245	245
Circuit 38	950	826	4,619	5,333	5,342	5,342	5,342	5,342	5,342	5,342
Circuit 39	4,118	3,580	4,086	4,718	4,761	4,761	4,761	4,761	4,761	4,761
Circuit 40	2,366	2,057	570	659	669	676	683	705	748	783
Circuit 41	12,197	10,606	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083
Circuit 42	1,255	1,091	331	382	388	392	396	409	434	454
Circuit 43	4,481	3,897	2,853	2,853	2,853	2,853	2,853	2,853	2,853	2,853
Circuit 44	1,354	1,178	1,030	1,190	1,206	1,206	1,206	1,206	1,206	1,206
Circuit 45	1,502	1,306	1,415	1,634	1,660	1,678	1,694	1,732	1,732	1,732
Circuit 46	1,286	1,119	1,210	1,210	1,210	1,210	1,210	1,210	1,210	1,210
Circuit 47	–	–	–	–	–	–	–	–	–	–
Circuit 48	1,470	1,278	670	670	670	670	670	670	670	670
Circuit 49	–	–	22	26	26	26	26	27	29	30
Circuit 50	–	–	–	–	–	–	–	–	–	–
Circuit 51	4,885	4,248	501	579	588	595	600	600	600	600
Circuit 52	2,255	1,961	3,066	3,278	3,278	3,278	3,278	3,278	3,278	3,278
Circuit 53	1,557	1,354	995	995	995	995	995	995	995	995
Circuit 54	–	–	227	227	227	227	227	227	227	227
Circuit 55	850	740	1,304	1,418	1,418	1,418	1,418	1,418	1,418	1,418
Circuit 56	319	277	476	549	558	564	569	588	589	589
Circuit 57	510	443	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465
Circuit 58	1,424	1,238	1,892	1,912	1,912	1,912	1,912	1,912	1,912	1,912
Circuit 59	2,861	2,488	3,105	3,585	3,642	3,682	3,716	3,840	3,890	3,890
Circuit 60	1,036	901	7	8	8	8	8	9	9	10
Circuit 61	5,040	4,383	4,584	5,028	5,028	5,028	5,028	5,028	5,028	5,028
Circuit 62	1,285	1,118	395	456	463	468	473	488	518	542
Circuit 63	13,815	12,013	1,980	2,286	2,322	2,348	2,370	2,449	2,534	2,534
Circuit 64	4,346	3,779	466	466	466	466	466	466	466	466
Circuit 65	5,733	4,986	2,636	2,706	2,706	2,706	2,706	2,706	2,706	2,706
Circuit 66	714	621	34	34	34	34	34	34	34	34
Circuit 67	738	642	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
Circuit 68	1,792	1,558	2,328	2,688	2,731	2,760	2,786	2,871	2,871	2,871
Circuit 69	3,834	3,334	3,544	3,862	3,862	3,862	3,862	3,862	3,862	3,862
Circuit 70	3,736	3,249	1,137	1,195	1,195	1,195	1,195	1,195	1,195	1,195
Circuit 71	1,720	1,496	430	496	504	510	515	532	564	583
Circuit 72	3,406	2,962	899	1,037	1,054	1,066	1,076	1,111	1,178	1,183
Circuit 73	7,841	6,818	7,736	8,933	9,076	9,174	9,261	9,521	9,521	9,521
Circuit 74	830	722	257	297	301	305	308	311	311	311

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	951	827	100	100	100	100	100	100	100	100
Circuit 76	4,062	3,532	2,348	2,706	2,706	2,706	2,706	2,706	2,706	2,706
Circuit 77	2,991	2,601	613	708	719	727	734	758	803	814
Circuit 78	5,882	5,115	1,443	1,666	1,693	1,694	1,694	1,694	1,694	1,694
Circuit 79	3,908	3,398	1,066	1,066	1,066	1,066	1,066	1,066	1,066	1,066
Circuit 80	3,928	3,416	438	504	504	504	504	504	504	504
Circuit 81	3,494	3,038	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Circuit 82	2,645	2,300	2,754	2,974	2,974	2,974	2,974	2,974	2,974	2,974
Circuit 83	1,596	1,388	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315
Circuit 84	3,169	2,756	2,207	2,548	2,589	2,617	2,642	2,730	2,894	2,913
Circuit 85	–	–	–	–	–	–	–	–	–	–
Circuit 86	5,449	4,738	2,896	3,344	3,398	3,435	3,467	3,488	3,488	3,488
Circuit 87	1,055	917	585	585	585	585	585	585	585	585
Circuit 88	560	487	909	909	909	909	909	909	909	909
Circuit 89	625	543	837	846	846	846	846	846	846	846
Circuit 90	418	364	597	611	611	611	611	611	611	611
Circuit 91	75	65	95	109	111	112	113	117	124	130
Circuit 92	1,002	872	1,214	1,402	1,425	1,440	1,454	1,462	1,462	1,462
Circuit 93	122	106	159	159	159	159	159	159	159	159
Circuit 94	207	180	316	364	370	374	378	390	414	433
Circuit 95	804	700	1,448	1,549	1,549	1,549	1,549	1,549	1,549	1,549
Circuit 96	276	240	299	299	299	299	299	299	299	299
Circuit 97	599	521	332	348	348	348	348	348	348	348
Circuit 98	1,037	902	56	56	56	56	56	56	56	56
Circuit 99	520	452	12	14	14	14	14	15	15	16
Circuit 100	377	328	382	382	382	382	382	382	382	382
Circuit 101	2106	1831	2,625	3,031	3,079	3,113	3,142	3,247	3,441	3,602
Circuit 102	2604	2265	644	661	661	661	661	661	661	661

Table N-17. Distribution Circuit Market DG-PV Forecast: Maui Electric (kW)

Maui Electric Distribution Circuit High DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	3,302	2,871	2,661	3,114	3,269	3,367	3,435	6,436	7,697	7,697
Circuit 2	1,233	1,072	916	1,072	1,125	1,159	1,182	2,215	3,342	3,874
Circuit 3	166	145	225	263	276	285	290	544	599	599
Circuit 4	22	19	43	50	53	54	55	104	138	138
Circuit 5	29	26	52	61	64	66	67	125	189	219
Circuit 6	188	163	284	332	349	359	366	686	1,035	1,200
Circuit 7	3,192	2,776	1,019	1,094	1,094	1,094	1,094	1,094	1,094	1,094
Circuit 8	3,602	3,132	3,292	3,851	4,044	4,165	4,248	7,077	7,077	7,077
Circuit 9	473	411	1,202	1,406	1,476	1,521	1,551	2,906	4,385	5,083
Circuit 10	330	287	1,073	1,255	1,318	1,358	1,385	2,595	3,915	4,539
Circuit 11	283	246	469	549	576	593	605	1,134	1,711	1,984
Circuit 12	77	67	12	14	15	15	15	29	43	44
Circuit 13	–	–	219	256	269	277	283	530	800	927
Circuit 14	5,807	5,049	1,917	2,242	2,355	2,425	2,474	4,635	6,240	6,240
Circuit 15	2,141	1,862	1,087	1,271	1,335	1,375	1,402	2,628	3,965	4,597
Circuit 16	5,115	4,448	2,219	2,597	2,726	2,808	2,864	5,367	6,252	6,252
Circuit 17	4,569	3,973	2,324	2,719	2,855	2,941	3,000	5,621	6,816	6,816
Circuit 18	6,033	5,246	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Circuit 19	8,174	7,108	9,043	9,462	9,462	9,462	9,462	9,462	9,462	9,462
Circuit 20	1,117	971	914	1,069	1,122	1,156	1,179	2,210	3,334	3,865
Circuit 21	199	173	33	38	40	42	42	79	120	139
Circuit 22	5,168	4,494	2,521	2,950	3,097	3,190	3,254	6,097	6,398	6,398
Circuit 23	5,963	5,185	3,453	4,040	4,242	4,369	4,457	7,346	7,346	7,346
Circuit 24	1,133	985	4,175	4,885	5,129	5,283	5,388	5,992	5,992	5,992
Circuit 25	1,806	1,570	4,827	5,648	5,930	6,108	6,230	8,241	8,241	8,241
Circuit 26	629	547	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Circuit 27	7,439	6,469	7,708	7,708	7,708	7,708	7,708	7,708	7,708	7,708
Circuit 28	539	469	614	718	754	777	792	1,485	2,240	2,597
Circuit 29	2,599	2,260	3,347	3,916	4,112	4,236	4,320	8,096	8,236	8,236
Circuit 30	2,103	1,829	3,118	3,648	3,830	3,945	4,024	7,540	8,085	8,085
Circuit 31	153	133	594	696	730	752	767	1,438	2,169	2,515
Circuit 32	6,784	5,899	1,717	1,717	1,717	1,717	1,717	1,717	1,717	1,717
Circuit 33	3,009	2,616	2,938	3,438	3,610	3,718	3,792	6,752	6,752	6,752
Circuit 34	2,091	1,818	633	741	778	801	817	1,531	2,310	2,678
Circuit 35	2,003	1,742	203	238	250	257	263	366	366	366
Circuit 36	2,361	2,053	3,295	3,855	4,048	4,169	4,253	6,854	6,854	6,854

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	1,728	1,502	279	327	343	353	361	535	535	535
Circuit 38	950	826	4,964	5,808	6,098	6,281	6,407	8,395	8,395	8,395
Circuit 39	4,118	3,580	4,391	5,138	5,395	5,557	5,668	7,838	7,838	7,838
Circuit 40	2,366	2,057	464	464	464	464	464	464	464	464
Circuit 41	12,197	10,606	2,598	2,598	2,598	2,598	2,598	2,598	2,598	2,598
Circuit 42	1,255	1,091	355	416	437	450	459	860	1,297	1,504
Circuit 43	4,481	3,897	3,704	4,333	4,550	4,686	4,780	6,631	6,631	6,631
Circuit 44	1,354	1,178	1,107	1,296	1,360	1,401	1,429	2,678	4,040	4,684
Circuit 45	1,502	1,306	1,520	1,779	1,868	1,924	1,962	3,677	5,548	6,432
Circuit 46	1,286	1,119	1,330	1,556	1,633	1,682	1,716	3,216	4,852	5,625
Circuit 47	–	–	–	–	–	–	–	–	–	–
Circuit 48	1,470	1,278	884	1,034	1,086	1,118	1,141	2,138	3,225	3,739
Circuit 49	–	–	24	28	29	30	31	57	87	101
Circuit 50	–	–	–	–	–	–	–	–	–	–
Circuit 51	4,885	4,248	539	630	662	682	696	1,043	1,043	1,043
Circuit 52	2,255	1,961	3,295	3,855	4,048	4,169	4,253	5,720	5,720	5,720
Circuit 53	1,557	1,354	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Circuit 54	–	–	299	350	368	379	386	724	1,092	1,266
Circuit 55	850	740	1,402	1,640	1,722	1,774	1,809	3,390	5,115	5,930
Circuit 56	319	277	511	598	628	647	660	1,236	1,865	2,162
Circuit 57	510	443	1,712	2,003	2,103	2,166	2,209	4,140	6,246	6,624
Circuit 58	1,424	1,238	2,033	2,379	2,498	2,573	2,624	4,918	6,504	6,504
Circuit 59	2,861	2,488	3,337	3,904	4,099	4,222	4,306	8,070	8,628	8,628
Circuit 60	1,036	901	7	9	9	9	10	18	27	31
Circuit 61	5,040	4,383	4,927	5,764	6,052	6,234	6,359	8,835	8,835	8,835
Circuit 62	1,285	1,118	424	496	521	537	548	1,026	1,548	1,795
Circuit 63	13,815	12,013	2,128	2,489	2,614	2,692	2,746	3,617	3,617	3,617
Circuit 64	4,346	3,779	616	720	756	779	795	1,236	1,236	1,236
Circuit 65	5,733	4,986	2,833	3,315	3,481	3,585	3,657	6,852	7,565	7,565
Circuit 66	714	621	45	52	55	57	58	108	163	164
Circuit 67	738	642	1,275	1,492	1,566	1,613	1,646	3,084	4,653	5,394
Circuit 68	1,792	1,558	2,502	2,927	3,073	3,165	3,229	6,050	6,810	6,810
Circuit 69	3,834	3,334	3,808	4,456	4,679	4,819	4,915	7,941	7,941	7,941
Circuit 70	3,736	3,249	1,222	1,429	1,501	1,546	1,577	2,955	4,458	5,168
Circuit 71	1,720	1,496	462	540	567	584	596	1,117	1,686	1,954
Circuit 72	3,406	2,962	966	1,130	1,186	1,222	1,246	2,336	3,524	4,085
Circuit 73	7,841	6,818	8,314	9,190	9,190	9,190	9,190	9,190	9,190	9,190
Circuit 74	830	722	276	323	339	349	356	668	1,008	1,168

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	951	827	132	154	162	167	170	319	481	557
Circuit 76	4,062	3,532	2,523	2,952	3,100	3,193	3,257	6,103	6,758	6,758
Circuit 77	2,991	2,601	659	735	735	735	735	735	735	735
Circuit 78	5,882	5,115	1,551	1,815	1,834	1,834	1,834	1,834	1,834	1,834
Circuit 79	3,908	3,398	1,407	1,646	1,729	1,780	1,816	3,403	5,134	5,946
Circuit 80	3,928	3,416	471	551	578	596	608	1,139	1,241	1,241
Circuit 81	3,494	3,038	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Circuit 82	2,645	2,300	2,960	3,463	3,636	3,745	3,820	7,036	7,036	7,036
Circuit 83	1,596	1,388	1,735	2,030	2,132	2,196	2,240	4,197	6,332	6,769
Circuit 84	3,169	2,756	2,372	2,775	2,914	3,001	3,061	5,736	6,224	6,224
Circuit 85	–	–	–	–	–	–	–	–	–	–
Circuit 86	5,449	4,738	3,112	3,642	3,824	3,938	4,017	6,833	6,833	6,833
Circuit 87	1,055	917	717	838	880	907	925	1,733	2,615	3,031
Circuit 88	560	487	1,056	1,235	1,297	1,336	1,362	2,553	3,852	4,465
Circuit 89	625	543	900	1,052	1,105	1,138	1,161	2,176	3,282	3,805
Circuit 90	418	364	642	751	788	812	828	1,552	2,341	2,714
Circuit 91	75	65	102	119	125	129	131	246	249	249
Circuit 92	1,002	872	1,305	1,527	1,603	1,651	1,684	1,688	1,688	1,688
Circuit 93	122	106	191	208	212	218	225	366	512	593
Circuit 94	207	180	319	347	354	365	376	612	855	991
Circuit 95	804	700	1,462	1,594	1,626	1,675	1,725	1,728	1,728	1,728
Circuit 96	276	240	346	378	385	397	409	665	930	959
Circuit 97	599	521	335	365	372	383	395	500	500	500
Circuit 98	1,037	902	57	62	63	65	67	109	152	176
Circuit 99	520	452	12	13	13	14	14	23	32	37
Circuit 100	377	328	474	541	573	619	663	2,227	2,759	2,759
Circuit 101	2,106	1,831	2,188	2,188	2,188	2,188	2,188	2,188	2,188	2,188
Circuit 102	2,604	2,265	661	753	799	862	923	2,753	2,753	2,753

Table N-18. Distribution Circuit High DG-PV Forecast: Maui Electric (kW)

Hawai'i Electric Light Distribution Circuit Market DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,279	5,337	1,334	1,549	1,612	1,659	1,706	1,996	2,370	2,701
Circuit 2	1,552	1,319	340	395	411	423	435	509	604	689
Circuit 3	1,952	1,659	–	–	–	–	–	–	–	–
Circuit 4	2,529	2,150	261	303	315	325	334	390	464	528
Circuit 5	4,994	4,245	83	96	100	103	106	124	148	168
Circuit 6	2,621	2,228	–	–	–	–	–	–	–	–
Circuit 7	4,560	3,876	925	1,074	1,117	1,150	1,183	1,384	1,643	1,872
Circuit 8	4,641	1,795	1,044	1,212	1,261	1,299	1,335	1,562	1,855	2,114
Circuit 9	846	375	217	253	263	270	278	325	386	440
Circuit 10	2,200	85	348	404	420	433	445	520	618	704
Circuit 11	199	–	–	–	–	–	–	–	–	–
Circuit 12	3,846	85	100	100	100	100	100	100	100	100
Circuit 13	1,457	83	123	142	148	153	157	184	218	248
Circuit 14	2,504	2,129	397	461	480	494	508	594	706	804
Circuit 15	149	127	7	8	8	9	9	10	12	14
Circuit 16	2,012	598	877	1,018	1,059	1,087	1,087	1,087	1,087	1,087
Circuit 17	1,602	953	292	339	352	363	373	436	518	590
Circuit 18	2,881	624	517	600	624	642	661	773	918	1,046
Circuit 19	2,223	1,597	587	681	709	730	750	878	1,042	1,188
Circuit 20	696	272	133	154	161	165	170	199	236	269
Circuit 21	3,504	1,040	1,530	1,777	1,848	1,903	1,957	2,289	2,718	3,098
Circuit 22	2,080	85	76	88	91	94	97	113	134	153
Circuit 23	5,493	2,714	2,993	3,476	3,616	3,723	3,828	4,478	5,317	6,060
Circuit 24	2,781	851	619	719	748	771	792	927	1,101	1,254
Circuit 25	8,169	2,431	4,542	5,275	5,488	5,650	5,810	6,797	8,070	9,197
Circuit 26	1,155	–	–	–	–	–	–	–	–	–
Circuit 27	3,789	3,221	1,728	2,006	2,087	2,149	2,209	2,585	3,069	3,194
Circuit 28	5,923	5,034	1,185	1,376	1,431	1,474	1,515	1,773	2,105	2,399
Circuit 29	1,408	1,196	179	207	216	222	228	267	317	362
Circuit 30	4,644	1,857	1,758	2,042	2,124	2,187	2,249	2,631	3,124	3,560
Circuit 31	8,263	7,029	1,080	1,254	1,304	1,343	1,381	1,616	1,918	2,186
Circuit 32	6,539	5,558	231	231	231	231	231	231	231	231
Circuit 33	10,737	9,123	2,510	2,915	3,032	3,122	3,210	3,755	4,459	4,808
Circuit 34	3,243	2,756	1,124	1,305	1,358	1,398	1,438	1,682	1,997	2,276
Circuit 35	312	215	281	326	339	349	359	420	499	569
Circuit 36	3,291	1,818	812	943	981	1,010	1,038	1,137	1,137	1,137

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	841	715	109	127	132	136	139	163	194	221
Circuit 38	2,653	2,255	88	102	106	110	113	132	157	178
Circuit 39	2,479	2,107	1,006	1,168	1,215	1,251	1,287	1,505	1,787	2,037
Circuit 40	1,492	533	442	514	534	550	566	662	786	895
Circuit 41	3,459	460	631	733	762	785	807	944	1,121	1,277
Circuit 42	1,309	424	541	629	654	673	692	810	962	1,056
Circuit 43	962	81	119	138	144	148	152	178	211	241
Circuit 44	5,490	770	871	1,012	1,053	1,084	1,114	1,304	1,548	1,764
Circuit 45	1,506	764	712	827	860	885	910	1,065	1,265	1,441
Circuit 46	6,002	599	756	878	913	940	967	1,131	1,343	1,530
Circuit 47	5,097	284	298	347	361	371	382	447	530	604
Circuit 48	661	146	203	235	245	252	259	303	360	410
Circuit 49	1,526	146	144	168	174	179	184	216	256	292
Circuit 50	1,324	315	522	607	631	650	668	782	906	906
Circuit 51	1,167	2,043	1,421	1,421	1,421	1,421	1,421	1,421	1,421	1,421
Circuit 52	3,211	6,199	7,168	7,168	7,168	7,168	7,168	7,168	7,168	7,168
Circuit 53	2,988	864	1,047	1,216	1,265	1,302	1,339	1,567	1,860	2,080
Circuit 54	4,007	3,406	1,566	1,818	1,891	1,947	2,002	2,343	2,782	3,170
Circuit 55	1,677	1,425	494	574	597	614	632	739	877	1,000
Circuit 56	352	299	123	143	148	153	157	184	218	248
Circuit 57	1,035	548	429	499	519	534	549	643	763	870
Circuit 58	74	62	10	10	10	10	10	10	10	10
Circuit 59	3,462	1,758	1,648	1,914	1,991	2,050	2,108	2,466	2,928	3,337
Circuit 60	2,628	2,108	1,611	1,871	1,946	2,004	2,061	2,411	2,862	3,262
Circuit 61	1,448	1,252	945	1,097	1,141	1,175	1,209	1,414	1,679	1,913
Circuit 62	1,489	1,274	119	138	144	148	152	178	211	241
Circuit 63	1,958	940	504	586	609	627	645	754	896	1,021
Circuit 64	1,586	1,354	158	183	190	196	202	236	280	319
Circuit 65	2,879	2,471	509	591	615	633	651	762	904	1,031
Circuit 66	1,858	1,579	694	806	838	863	888	900	900	900
Circuit 67	586	498	–	–	–	–	–	–	–	–
Circuit 68	1,132	283	209	242	252	260	267	312	371	422
Circuit 69	1,920	480	402	467	486	500	514	602	714	814
Circuit 70	1,937	1,674	804	933	971	1,000	1,028	1,202	1,428	1,627
Circuit 71	2,692	2,328	400	465	484	498	512	599	711	811
Circuit 72*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Circuit 73	6,379	4,121	2,866	3,328	3,462	3,564	3,665	4,288	5,091	5,802
Circuit 74	6,752	3,386	3,543	4,115	4,281	4,407	4,532	5,302	6,295	7,174

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	515	438	194	226	235	242	248	291	345	393
Circuit 76	7,449	3,229	2,790	3,240	3,370	3,470	3,568	4,175	4,957	5,649
Circuit 77	851	724	597	693	721	742	763	893	1,060	1,208
Circuit 78	5,542	1,949	2,658	3,087	3,211	3,306	3,400	3,977	4,723	5,382
Circuit 79	119	76	–	–	–	–	–	–	–	–
Circuit 80	226	120	–	–	–	–	–	–	–	–
Circuit 81	1,463	480	750	871	906	933	959	1,122	1,332	1,518
Circuit 82	6,860	4,489	2,500	2,904	3,021	3,110	3,198	3,741	4,442	5,062
Circuit 83	245	208	193	224	233	240	247	289	343	391
Circuit 84	227	57	72	84	87	89	92	108	128	146
Circuit 85	676	190	189	220	229	236	242	283	337	384
Circuit 86	469	399	259	301	313	322	332	388	461	525
Circuit 87	233	198	143	167	173	178	184	215	255	291
Circuit 88	9,204	7,823	1,641	1,906	1,982	2,041	2,099	2,455	2,915	3,322
Circuit 89	2,002	1,701	860	999	1,039	1,070	1,100	1,287	1,528	1,741
Circuit 90	3,210	2,805	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Circuit 91	2,905	938	662	769	800	824	847	991	1,176	1,341
Circuit 92	376	122	147	171	178	183	188	220	261	298
Circuit 93	859	128	167	194	202	208	214	251	298	339
Circuit 94	324	117	161	187	194	200	205	240	285	325
Circuit 95	331	43	45	52	54	56	57	67	80	91
Circuit 96	1,129	219	182	211	220	226	233	272	323	369
Circuit 97	5,660	4,811	388	450	469	482	496	580	689	785
Circuit 98	4,943	4,202	374	434	452	465	478	559	664	757
Circuit 99	991	172	162	188	196	202	208	243	288	329
Circuit 100	1,001	851	270	313	326	336	345	404	479	546
Circuit 101	364	310	52	60	62	64	66	77	92	105
Circuit 102	2,812	2,390	636	738	768	791	813	951	1,129	1,287
Circuit 103	4,907	4,171	1,582	1,838	1,912	1,968	2,024	2,368	2,811	3,204
Circuit 104	4,623	2,681	2,622	3,045	3,167	3,261	3,353	3,923	4,658	5,309
Circuit 105	6,136	1,483	1,744	2,026	2,107	2,170	2,231	2,610	3,099	3,531
Circuit 106	722	171	175	203	212	218	224	262	311	355
Circuit 107	408	126	186	216	225	231	238	278	330	377
Circuit 108	311	–	–	–	–	–	–	–	–	–
Circuit 109	3,792	3,223	691	802	835	859	884	1,034	1,227	1,399
Circuit 110	5,574	4,738	272	316	329	339	349	408	484	552
Circuit 111	4,103	626	252	292	304	313	322	377	447	510
Circuit 112	4,693	3,989	1,143	1,327	1,381	1,422	1,462	1,710	2,031	2,314

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 113	1,316	1,118	16	19	19	20	20	24	28	32
Circuit 114	798	678	133	154	161	165	170	199	236	269
Circuit 115	146	124	500	500	500	500	500	500	500	500
Circuit 116	762	648	500	500	500	500	500	500	500	500
Circuit 117	2,610	836	843	979	1,018	1,048	1,078	1,261	1,497	1,706
Circuit 118	6,995	1,070	1,164	1,352	1,406	1,448	1,489	1,742	2,068	2,357
Circuit 119	2,666	585	521	605	630	648	667	780	926	1,055
Circuit 120	2,396	2,037	856	994	1,034	1,064	1,094	1,280	1,520	1,732
Circuit 121	58	–	100	–	–	–	–	–	–	–
Circuit 122	351	167	174	202	210	216	222	260	309	352
Circuit 123	944	802	150	175	182	187	192	225	267	304
Circuit 124	1,117	16	4	4	4	5	5	5	6	7
Circuit 125	3,522	1,008	883	1,025	1,066	1,098	1,129	1,321	1,568	1,787
Circuit 126	1,518	1,129	504	585	609	627	645	754	895	1,020
Circuit 127	192	163	47	54	56	58	60	70	83	95
Circuit 128	118	101	46	53	55	57	59	69	81	93
Circuit 129	1,990	1,691	1,158	1,345	1,399	1,440	1,481	1,733	2,057	2,345
Circuit 130	816	694	463	537	559	576	592	692	822	937
Circuit 131	4,112	3,495	1,038	1,206	1,254	1,291	1,328	1,553	1,844	2,102
Circuit 132	3,475	2,954	2,236	2,597	2,701	2,782	2,860	3,346	3,973	4,528
Circuit 133	1,271	–	–	–	–	–	–	–	–	–
Circuit 134	952	–	–	–	–	–	–	–	–	–
Circuit 135	698	435	255	296	308	317	326	382	453	517
Circuit 136	1,928	1,606	611	710	738	760	782	915	1,086	1,238

* Circuit 72 is a backup circuit without any connections.

Table N-19. Distribution Circuit Market DG-PV Forecast: Hawai‘i Electric Light (kW)

Hawai‘i Electric Light Distribution Circuit High DG-PV Forecast (kW)

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 1	6,279	5,337	1,904	2,325	2,484	2,544	2,606	5,591	8,837	10,210
Circuit 2	1,552	1,319	534	652	697	713	731	1,568	2,478	2,933
Circuit 3	1,952	1,659	68	83	89	91	93	200	316	374
Circuit 4	2,529	2,150	420	513	548	561	575	1,234	1,950	2,308
Circuit 5	4,994	4,245	162	198	212	217	222	476	753	891
Circuit 6	2,621	2,228	68	83	89	91	93	200	316	374
Circuit 7	4,560	3,876	1,666	2,036	2,175	2,227	2,281	4,894	7,538	7,538
Circuit 8	4,641	1,795	1,310	1,600	1,709	1,750	1,793	3,846	5,416	5,416
Circuit 9	846	375	328	401	428	439	449	964	1,524	1,804
Circuit 10	2,200	85	491	600	641	656	672	1,442	2,279	2,698
Circuit 11	199	–	68	83	89	91	93	200	316	374
Circuit 12	3,846	85	136	166	178	182	186	400	632	737
Circuit 13	1,457	83	134	163	174	178	183	392	620	734
Circuit 14	2,504	2,129	756	924	987	1,011	1,036	2,222	3,512	4,157
Circuit 15	149	127	7	9	10	10	10	22	35	41
Circuit 16	2,012	598	742	907	969	992	1,016	2,180	2,610	2,610
Circuit 17	1,602	953	365	445	476	487	499	1,071	1,692	2,003
Circuit 18	2,881	624	740	904	966	990	1,014	2,174	3,437	4,068
Circuit 19	2,223	1,597	822	1,004	1,073	1,099	1,126	2,415	3,817	4,518
Circuit 20	696	272	201	246	263	269	275	591	934	1,105
Circuit 21	3,504	1,040	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223
Circuit 22	2,080	85	82	100	107	110	113	242	382	452
Circuit 23	5,493	2,714	4,517	5,517	5,895	6,036	6,183	13,265	17,295	17,295
Circuit 24	2,781	851	930	1,136	1,213	1,242	1,273	2,730	4,315	4,838
Circuit 25	8,169	2,431	6,101	7,453	7,963	8,154	8,352	16,854	16,854	16,854
Circuit 26	1,155	–	68	83	89	91	93	200	316	374
Circuit 27	3,789	3,221	2,331	2,848	3,042	3,115	3,191	6,846	6,960	6,960
Circuit 28	5,923	5,034	1,423	1,738	1,857	1,902	1,948	4,179	6,606	7,579
Circuit 29	1,408	1,196	280	341	365	374	383	821	1,298	1,461
Circuit 30	4,644	1,857	2,054	2,509	2,681	2,745	2,812	2,934	2,934	2,934
Circuit 31	8,263	7,029	1,608	1,964	2,098	2,149	2,201	4,280	4,280	4,280
Circuit 32	6,539	5,558	42	52	55	56	58	124	196	230
Circuit 33	10,737	9,123	3,416	4,172	4,458	4,565	4,676	10,031	15,856	17,214
Circuit 34	3,243	2,756	1,749	1,946	1,946	1,946	1,946	1,946	1,946	1,946
Circuit 35	312	215	389	475	507	520	532	1,142	1,230	1,230
Circuit 36	3,291	1,818	1,303	1,591	1,700	1,741	1,783	1,866	1,866	1,866

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 37	841	715	121	148	158	162	166	355	562	665
Circuit 38	2,653	2,255	96	117	125	128	131	282	445	527
Circuit 39	2,479	2,107	1,388	1,696	1,812	1,855	1,901	4,077	5,428	5,428
Circuit 40	1,492	533	864	1,056	1,128	1,155	1,183	2,538	3,044	3,044
Circuit 41	3,459	460	1,051	1,284	1,372	1,405	1,439	3,087	3,746	3,746
Circuit 42	1,309	424	651	795	850	870	891	1,913	3,023	3,530
Circuit 43	962	81	129	158	169	173	177	380	600	710
Circuit 44	5,490	770	1,237	1,511	1,614	1,653	1,693	3,633	5,618	5,618
Circuit 45	1,506	764	1,564	1,910	2,041	2,090	2,141	2,389	2,389	2,389
Circuit 46	6,002	599	1,149	1,404	1,500	1,536	1,573	1,887	1,887	1,887
Circuit 47	5,097	284	463	565	604	618	633	1,359	2,148	2,543
Circuit 48	661	146	271	331	354	362	371	796	1,259	1,490
Circuit 49	1,526	146	251	306	327	335	343	737	1,165	1,379
Circuit 50	1,324	315	660	806	861	882	903	1,938	3,063	3,626
Circuit 51	1,167	2,043	272	332	355	363	372	798	1,262	1,494
Circuit 52	3,211	6,199	734	896	957	980	1,004	2,154	3,405	4,031
Circuit 53	2,988	864	1,436	1,754	1,874	1,919	1,966	4,217	6,666	7,808
Circuit 54	4,007	3,406	2,184	2,668	2,851	2,919	2,990	6,416	9,266	9,266
Circuit 55	1,677	1,425	709	867	926	948	971	2,084	3,293	3,737
Circuit 56	352	299	201	246	263	269	275	591	934	1,106
Circuit 57	1,035	548	499	610	652	667	684	1,437	1,437	1,437
Circuit 58	74	62	14	17	18	18	19	40	63	75
Circuit 59	3,462	1,758	2,365	2,889	3,087	3,161	3,238	6,946	8,762	8,762
Circuit 60	2,628	2,108	2,211	2,701	2,886	2,955	3,027	6,407	6,407	6,407
Circuit 61	1,448	1,252	962	962	962	962	962	962	962	962
Circuit 62	1,489	1,274	286	349	373	382	391	776	776	776
Circuit 63	1,958	940	701	856	915	937	959	2,058	3,253	3,850
Circuit 64	1,586	1,354	218	266	284	291	298	639	1,010	1,196
Circuit 65	2,879	2,471	702	857	916	938	961	2,061	3,257	3,705
Circuit 66	1,858	1,579	735	898	959	982	1,006	2,159	2,749	2,749
Circuit 67	586	498	68	83	89	91	93	200	316	374
Circuit 68	1,132	283	283	346	370	379	388	832	1,315	1,557
Circuit 69	1,920	480	552	674	720	737	755	1,620	2,560	3,031
Circuit 70	1,937	1,674	1,040	1,270	1,357	1,390	1,424	3,054	4,135	4,135
Circuit 71	2,692	2,328	1,337	1,633	1,745	1,786	1,830	3,926	6,122	6,122
Circuit 72*	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Circuit 73	6,379	4,121	3,590	4,385	4,685	4,798	4,914	10,543	14,919	14,919
Circuit 74	6,752	3,386	4,561	5,572	5,953	6,096	6,244	13,396	15,389	15,389

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 75	515	438	236	288	308	315	323	693	995	995
Circuit 76	7,449	3,229	3,942	4,816	5,145	5,269	5,397	11,578	12,755	12,755
Circuit 77	851	724	849	1,037	1,108	1,134	1,162	2,439	2,439	2,439
Circuit 78	5,542	1,949	3,631	4,436	4,739	4,853	4,971	8,743	8,743	8,743
Circuit 79	119	76	68	83	89	91	93	200	316	374
Circuit 80	226	120	68	83	89	91	93	200	316	374
Circuit 81	1,463	480	1,014	1,238	1,323	1,355	1,388	2,977	4,705	5,363
Circuit 82	6,860	4,489	3,039	3,712	3,966	4,062	4,160	8,925	10,103	10,103
Circuit 83	245	208	293	358	383	392	401	861	1,169	1,169
Circuit 84	227	57	84	102	109	112	114	245	388	459
Circuit 85	676	190	226	276	295	302	310	665	1,050	1,243
Circuit 86	469	399	420	513	548	561	575	1,234	1,545	1,545
Circuit 87	233	198	189	231	246	252	259	555	877	1,038
Circuit 88	9,204	7,823	3,236	3,953	4,224	4,325	4,430	4,930	4,930	4,930
Circuit 89	2,002	1,701	1,322	1,615	1,725	1,766	1,809	3,557	3,557	3,557
Circuit 90	3,210	2,805	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Circuit 91	2,905	938	1,038	1,268	1,354	1,387	1,421	3,047	4,817	5,702
Circuit 92	376	122	217	265	284	290	298	638	1,009	1,194
Circuit 93	859	128	201	245	262	269	275	590	933	1,104
Circuit 94	324	117	461	563	601	616	631	1,307	1,307	1,307
Circuit 95	331	43	68	83	89	91	94	201	317	375
Circuit 96	1,129	219	343	419	448	458	469	1,007	1,592	1,884
Circuit 97	5,660	4,811	501	612	654	670	686	1,472	1,559	1,559
Circuit 98	4,943	4,202	848	1,035	1,106	1,133	1,160	1,837	1,837	1,837
Circuit 99	991	172	273	333	356	365	373	801	1,266	1,499
Circuit 100	1,001	851	426	520	556	569	583	1,250	1,976	2,339
Circuit 101	364	310	80	98	104	107	109	235	371	439
Circuit 102	2,812	2,390	881	1,076	1,150	1,177	1,206	1,425	1,425	1,425
Circuit 103	4,907	4,171	2,107	2,574	2,750	2,816	2,885	6,189	7,161	7,161
Circuit 104	4,623	2,681	3,043	3,615	3,615	3,615	3,615	3,615	3,615	3,615
Circuit 105	6,136	1,483	2,274	2,777	2,968	3,039	3,113	4,984	4,984	4,984
Circuit 106	722	171	283	346	369	378	387	831	1,313	1,554
Circuit 107	408	126	202	247	264	270	277	594	701	701
Circuit 108	311	–	68	83	89	91	93	200	316	374
Circuit 109	3,792	3,223	1,406	1,409	1,409	1,409	1,409	1,409	1,409	1,409
Circuit 110	5,574	4,738	825	1,008	1,077	1,103	1,130	1,775	1,775	1,775
Circuit 111	4,103	626	521	636	679	696	713	1,472	1,472	1,472
Circuit 112	4,693	3,989	1,433	1,433	1,433	1,433	1,433	1,433	1,433	1,433

Circuit	OCL	HC	2016	2017	2018	2019	2020	2030	2040	2045
Circuit 113	1,316	1,118	17	21	23	23	24	51	81	96
Circuit 114	798	678	185	226	241	247	253	543	858	1,016
Circuit 115	146	124	680	758	758	758	758	758	758	758
Circuit 116	762	648	680	710	710	710	710	710	710	710
Circuit 117	2,610	836	1,366	1,668	1,782	1,825	1,869	4,011	6,339	7,369
Circuit 118	6,995	1,070	2,138	2,612	2,791	2,858	2,927	6,153	6,153	6,153
Circuit 119	2,666	585	954	1,165	1,245	1,274	1,305	2,800	4,427	4,952
Circuit 120	2,396	2,037	1,299	1,587	1,696	1,736	1,778	3,815	6,031	6,571
Circuit 121	58	–	136	166	178	182	186	400	632	748
Circuit 122	351	167	271	331	353	362	371	795	1,257	1,264
Circuit 123	944	802	234	286	305	313	320	687	1,087	1,286
Circuit 124	1,117	16	679	829	886	907	929	957	957	957
Circuit 125	3,522	1,008	1,620	1,979	2,115	2,165	2,218	4,758	5,067	5,067
Circuit 126	1,518	1,129	686	838	895	917	939	2,014	3,184	3,768
Circuit 127	192	163	51	62	66	68	70	149	236	280
Circuit 128	118	101	146	179	191	196	200	430	680	805
Circuit 129	1,990	1,691	1,661	2,029	2,168	2,220	2,274	3,257	3,257	3,257
Circuit 130	816	694	744	909	971	994	1,019	1,084	1,084	1,084
Circuit 131	4,112	3,495	1,227	1,499	1,601	1,640	1,679	3,603	5,695	6,741
Circuit 132	3,475	2,954	3,196	3,904	4,171	4,271	4,375	9,235	9,235	9,235
Circuit 133	1,271	–	68	83	89	91	93	200	316	374
Circuit 134	952	–	68	83	89	91	93	200	316	374
Circuit 135	698	435	493	603	644	659	675	1,449	2,111	2,111
Circuit 136	1,928	1,606	874	1,067	1,140	1,167	1,196	2,565	4,055	4,800

* Circuit 72 is a backup circuit without any connections.

Table N-20. Distribution Circuit High DG-PV Forecast: Hawai'i Electric Light (kW)

INTEGRATION STRATEGY COST ESTIMATES

Table N-21 through Table N-55 include the annualized cost and volumes of for each integration strategy, by island, in the near-, mid-, and long-term planning horizons.

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$11,336	$3,322	$6,125	$20,784
Distribution Transformer	$12,565	$13,737	–	$26,302
Overhead Conductor	$1,574	$2,584	$6,480	$10,638
Underground Conductor	$951	$1,547	$1,358	$3,856
Substation Transformer	$17,977	$12,433	$61,874	$92,284
46kV Grounding Transformer	$19,904	$11,048	$6,651	$37,602
Grand Total	*$64,307*	*$44,672*	*$82,488*	*$191,466*
Voltage Regulators (qty)	259	68	99	426
Distribution Transformer (qty)	880	880	–	1,760
Overhead Conductor (feet)	7	11	20	38
Underground Conductor (feet)	1,133	1,601	1,171	3,905
Substation Transformer (qty)	5	4	12	21
46kV Grounding Transformer (qty)	20	10	5	35

Table N-21. Integration Strategy 1 Annualized Cost and Volumes: O‘ahu

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$116,445	$43,630	$103,495	$263,570
Replacement BESS	–	$77,815	$155,004	$232,819
Var Compensation Devices	$7,300	$14,552	$27,776	$49,628.09
DER Controls	$15,792	$25,925	$42,838	$84,554
46kV Grounding Transformer	$19,904	$11,048	$6,651	$37,602
Grand Total	*$159,440*	*$172,969*	*$335,764*	*$668,174*
BESS (kW)	30,817	16,682	45,022	92,521
BESS (kWh)	123,268	66,728	180,088	370,084
Replacement BESS (kW)	–	30,817	67,523	98,340
Replacement BESS (kWh)	–	123,268	270,092	393,360
Var Compensation Devices (kW)	8,283	14,383	21,861	44,527
46kV Grounding Transformer (qty)	20	10	5	35

Table N-22. Integration Strategy 2 Annualized Cost and Volumes: O‘ahu

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Substation Transformer	$4,072	–	–	$4,072
Var Compensation Devices	$3,786	$14,552	$27,776	$46,114
Overhead Conductor	$1,574	$2,584	$6,480	$10,638
Underground Conductor	$951	$1,547	$1,358	$3,856
DER Controls	$15,792	$25,925	$42,838	$84,554
46kV Grounding Transformer	$19,904	$11,048	$6,651	$37,602
Grand Total	*$52,203*	*$55,656*	*$85,103*	*$192,961*
Voltage Regulators (qty)	140	–	–	140
Substation Transformer (qty)	2	–	–	2
Var Compensation Devices (kW)	8,283	14,383	21,861	44,527
Overhead Conductor (feet)	7,278	10,582	20,370	38,230
Underground Conductor (feet)	1,133	1,601	1,171	3,905
46kV Grounding Transformer (qty)	20	10	5	35

Table N-23. Integration Strategy 3 Annualized Cost and Volumes: O‘ahu

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,130	$11,260	$7,324	$30,714
Distribution Transformer	$25,237	$27,591	–	$52,828
Overhead Conductor	$2,454	$7,654	$15,366	$25,473
Underground Conductor	$994	$6,062	$8,544	$15,600
Substation Transformer	$41,281	$138,875	$164,473	$344,629
46kV Grounding Transformer	$19,886	$16,921	-	$36,806
Grand Total	*$101,981*	*$208,362*	*$195,707*	*$506,051*
Voltage Regulators (qty)	270	214	107	591
Distribution Transformer (qty)	1,770	1,770	–	3,540
Overhead Conductor (feet)	11,448	30,517	50,316	92,281
Underground Conductor (feet)	1,173	6,172	7,129	14,474
Substation Transformer (qty)	9	46	32	87
46kV Grounding Transformer (qty)	20	15	-	35

Table N-24. Integration Strategy 4 Annualized Cost and Volumes: O‘ahu

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,130	$11,260	$7,324	$30,714
Distribution Transformer	$25,237	$27,591	–	$52,828
Overhead Conductor	$2,454	$7,654	$15,366	$25,473
Underground Conductor	$994	$6,062	$8,544	$15,600
Substation Transformer	$31,934	$40,316	$84,797	$157,047
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Transformer	$19,886	$16,921	-	$36,806
Grand Total	*$145,194*	*$251,705*	*$180,005*	*$576,904*
Voltage Regulators (qty)	270	214	107	591
Distribution Transformer (qty)	1,770	1,770	–	3,540
Overhead Conductor (feet)	11,448	30,517	50,316	92,281
Underground Conductor (feet)	1,173	6,172	7,129	14,474
Substation Transformer (qty)	6	11	20	37
46kV Grounding Transformer (qty)	20	15	-	35

Table N-25. Integration Strategy 5 Annualized Cost and Volumes: O‘ahu

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$129,997	$381,236	$427,831	$939,064
Replacement BESS	–	$69,845	$600,370	$670,214
Var Compensation Devices	$9,641	$25,831	$23,790	$59,262
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Transformer	$19,886	$16,921	-	$36,806
Grand Total	$212,083	$635,733	$1,115,965	$1,963,782
BESS (kW)	27,662	118,686	148,554	294,902
BESS (kWh)	110,648	474,744	594,216	1,179,608
Replacement BESS (kW)	–	27,662	262,385	290,047
Replacement BESS (kWh)	–	110,648	1,049,540	1,160,188
Var Compensation Devices (kW)	10,906	25,317	19,467	55,690
46kV Grounding Transformer (qty)	20	15	-	35

Table N-26. Integration Strategy 6 Annualized Cost and Volumes: O‘ahu

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$6,060	–	–	$6,060
Substation Transformer	$4,072	–	–	$4,072
Var Compensation Devices	$5,522	$25,831	$23,790	$55,143
BESS	–	$17,232	$99,427	$116,659
Replacement BESS	–	–	$27,666	$27,666
Overhead Conductor	$2,454	$7,654	$15,366	$25,473
Underground Conductor	$994	$6,062	$8,544	$15,600
DER Controls	$52,560	$141,901	$63,974	$258,436
46kV Grounding Transformer	$19,886	$16,921	-	$36,806
Grand Total	*$91,547*	*$215,601*	*$238,768*	*$545,915*
Voltage Regulators (qty)	137	–	–	137
Substation Transformer (qty)	2	–	–	2
Var Compensation Devices (kW)	10,906	25,317	19,467	55,690
BESS (kW)	–	5,083	31,056	36,139
BESS (kWh)	–	20,332	124,224	144,556
Replacement BESS (kW)	–	–	12,182	12,182
Replacement BESS (kWh)	–	–	48,728	48,728
Overhead Conductor (feet)	11,448	30,517	50,316	92,281
Underground Conductor (feet)	1,173	6,172	7,129	14,474
46kV Grounding Transformer (qty)	20	15	-	35

Table N-27. Integration Strategy 7 Annualized Cost and Volumes: O‘ahu

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$4,720	–	–	$4,720
Distribution Transformer	$4,426	$4,839	–	$9,265
Overhead Conductor	$5,332	$1,901	$348	$7,582
Underground Conductor	$5,114	$102	$71	$5,286
Substation Transformer	$42,704	$4,781	$5,033	$52,518
Grand Total	*$62,296*	*$11,623*	*$5,451*	*$79,370*
Voltage Regulators (qty)	111	–	–	111
Distribution Transformer (qty)	310	310	–	620
Overhead Conductor (feet)	25,244	7,786	1,211	34,242
Underground Conductor (feet)	6,236	110	61	6,407
Substation Transformer (qty)	16	1	3	20

Table N-28. Integration Strategy 1 Annualized Cost and Volumes: Maui

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$69,775	$2,981	$858	$73,614
Replacement BESS	–	$45,226	$45,705	$90,931
Var Compensation Devices	$8,951	$2,742	$975	$12,668
DER Controls	$564	$420	$394	$1,378
Grand Total	*$79,290*	*$51,369*	*$47,932*	*$178,591*
BESS (kW)	17,778	1,126	365	19,268
BESS (kWh)	71,111	4,503	1,459	77,074
Replacement BESS (kW)	–	17,778	19,797	37,575
Replacement BESS (kWh)	–	71,111	79,188	150,299
Var Compensation Devices (kW)	10,335	2,717	814	13,866

Table N-29. Integration Strategy 2 Annualized Cost and Volumes: Maui

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$2,903	–	–	$2,903
Substation Transformer	$42,704	–	–	$42,704
Var Compensation Devices	$1,582	$2,742	$975	$5,299
Overhead Conductor	$5,332	$1,901	$348	$7,582
Underground Conductor	$5,114	$102	$71	$5,286
DER Controls	$564	$420	$394	$1,378
Grand Total	*$58,198*	*$5,165*	*$1,788*	*$65,152*
Voltage Regulators (qty)	69	–	–	69
Substation Transformer (qty)	16	–	–	16
Var Compensation Devices (KW)	10,335	2,717	814	13,866
Overhead Conductor (feet)	25,244	7,786	1,211	34,242
Underground Conductor (feet)	6,236	110	61	6,407

Table N-30. Integration Strategy 3 Annualized Cost and Volumes: Maui

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$5,966	$1,741	$1,969	$9,676
Distribution Transformer	$20,369	$22,269	–	$42,638
Overhead Conductor	$5,975	$13,178	$16,083	$35,236
Underground Conductor	$2,686	$6,171	$11,211	$20,068
Substation Transformer	$35,288	$78,174	$24,510	$137,972
Grand Total	*$70,285*	*$121,534*	*$53,773*	*$245,591*
Voltage Regulators (qty)	140	35	32	207
Distribution Transformer (qty)	1,429	1,429	–	2,858
Overhead Conductor (feet)	27,639	53,547	52,471	133,657
Underground Conductor (feet)	3,182	6,390	9,304	18,875
Substation Transformer (qty)	11	16	4	31

Table N-31. Integration Strategy 4 Annualized Cost and Volumes: Maui

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$5,966	$1,741	$1,969	$9,676
Distribution Transformer	$20,369	$22,269	–	$42,638
Overhead Conductor	$5,975	$13,178	$16,083	$35,236
Underground Conductor	$2,686	$6,171	$11,211	$20,068
Substation Transformer	$25,144	$34,587	$12,085	$71,816
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$63,764*	*$104,438*	*$56,675*	*$224,876*
Voltage Regulators (qty)	140	35	32	207
Distribution Transformer (qty)	1,429	1,429	–	2,858
Overhead Conductor (feet)	27,639	53,547	52,471	133,657
Underground Conductor (feet)	3,182	6,390	9,304	18,875
Substation Transformer (qty)	8	8	3	19

Table N-32. Integration Strategy 5 Annualized Cost and Volumes: Maui

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$168,736	$216,615	$129,169	$514,520
Replacement BESS	–	$111,087	$443,313	$554,401
Var Compensation Devices	$6,460	$8,913	$4,857	$20,230
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$178,820*	*$363,106*	*$592,667*	*$1,134,592*
BESS (kW)	43,825	82,679	55,747	182,252
BESS (kWh)	175,301	330,718	222,989	729,008
Replacement BESS (kW)	–	43,825	192,843	236,668
Replacement BESS (kWh)	–	175,301	771,371	946,672
Var Compensation Devices (kW)	7,362	8,864	3,936	20,163

Table N-33. Integration Strategy 6 Annualized Cost and Volumes: Maui

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$3,449	–	–	$3,449
Substation Transformer	$35,288	–	–	$35,288
Var Compensation Devices	$2,519	$8,913	$4,857	$16,289
BESS	$4,210	$51,868	$67,688	$123,765
Replacement BESS	–	$2,932	$90,443	$93,374
Overhead Conductors	$5,975	$13,178	$16,083	$35,236
Underground Conductors	$2,686	$6,171	$11,211	$20,068
DER Controls	$3,624	$26,491	$15,327	$45,441
Grand Total	*$57,750*	*$109,552*	*$205,608*	*$372,910*
Voltage Regulators (qty)	82	–	–	82
Substation Transformer (qty)	11	–	–	11
Var Compensation Devices (kW)	7,362	8,864	3,936	20,163
BESS (kW)	1,173	20,234	29,261	50,668
BESS (kWh)	4,693	80,935	117,046	202,673
Replacement BESS (kW)	–	1,173	39,553	40,727
Replacement BESS (kWh)	–	4,693	158,214	162,907
Overhead Conductor (feet)	27,639	53,547	52,471	133,657
Underground Conductor (feet)	3,182	6,390	9,304	18,875

Table N-34. Integration Strategy 7 Annualized Cost and Volumes: Maui

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$636	–	–	$636
Distribution Transformer	$328	$358	–	$686
Overhead Conductor	–	–	–	–
Underground Conductor	–	–	–	–
Substation Transformer	–	–	–	–
Grand Total	*$964*	*$358*	–	*$1,323*
Voltage Regulators (qty)	15	–	–	15
Distribution Transformer (qty)	25	25	–	50
Overhead Conductor (feet)	–	–	–	–
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	–	–	–

Table N-35. Integration Strategy 1 Annualized Cost and Volumes: Molokaʻi

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$3,883	$58	$98	$4,039
Replacement BESS	–	$2,499	$2,370	$4,868
Var Compensation Devices	$368	$65	$30	$464
DER Controls	$16	$5	$11	$33
Grand Total	*$4,268*	*$2,627*	*$2,509*	*$9,404*
BESS (kW)	980	21	43	1,044
BESS (kWh)	3,920	85	171	4,175
Replacement BESS (kW)	–	980	1,025	2,005
Replacement BESS (kWh)	–	3,920	4,101	8,021
Var Compensation Devices (kW)	424	68	24	515

Table N-36. Integration Strategy 2 Annualized Cost and Volumes: Molokaʻi

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulator	$420	–	–	$420
Var Compensation Devices	$75	$65	$30	$170
DER Controls	$16	$5	$11	$33
Grand Total	*$511*	*$71*	*$41*	*$623*
Voltage Regulators (qty)	10	–	–	10
Var Compensation Devices (kW)	424	68	24	515

Table N-37. Integration Strategy 3 Annualized Cost and Volumes: Molokaʻi

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$636	–	–	$636
Distribution Transformer	$2,093	$2,451	–	$4,544
Overhead Conductor	–	–	–	–
Underground Conductor	–	–	–	–
Substation Transformer	–	–	–	–
Grand Total	*$2,729*	*$2,451*	–	*$5,181*
Voltage Regulators (qty)	15	–	–	15
Distribution Transformer (qty)	103	103	–	206
Overhead Conductor (feet)	–	–	–	–
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	–	–	–

Table N-38. Integration Strategy 4 Annualized Cost and Volumes: Moloka‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$636	–	–	$636
Distribution Transformer	$2,093	$2,451	–	$4,544
Overhead Conductor	–	–	–	–
Underground Conductor	–	–	–	–
Substation Transformer	–	–	–	–
DER Controls	$100	$199	$245	$545
Grand Total	*$2,830*	*$2,650*	*$245*	*$5,725*
Voltage Regulators (qty)	15	–	–	–
Distribution Transformer (qty)	103	103	–	206
Overhead Conductor (feet)	–	–	–	–
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	–	–	–

Table N-39. Integration Strategy 5 Annualized Cost and Volumes: Moloka‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$5,994	$1,677	$2,080	$9,750
Replacement BESS	–	$3,954	$6,550	$10,504
Var Compensation Devices	$334	$110	$77	$521
DER Controls	$100	$199	$245	$545
Grand Total	*$6,428*	*$5,941*	*$8,951*	*$21,320*
BESS (kW)	1,561	641	900	3,101
BESS (kWh)	6,242	2,562	3,599	12,403
Replacement BESS (kW)	–	1,561	2,848	4,408
Replacement BESS (kWh)	–	6,242	11,390	17,632
Var Compensation Devices (kW)	377	114	61	553

Table N-40. Integration Strategy 6 Annualized Cost and Volumes: Moloka'i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$420	–	–	$420
Var Compensation Devices	$199	$110	$77	$386
BESS	–	–	–	–
Replacement BESS	–	–	–	–
DER Controls	$100	$199	$245	$545
Grand Total	*$720*	*$309*	*$322*	*$1,351*
Voltage Regulators (qty)	10	–	–	10
Var Compensation Devices (kW)	377	114	61	553
BESS (kW)	–	–	–	–
BESS (kWh)	–	–	–	–
Replacement BESS (kW)	–	–	–	–
Replacement BESS (kWh)	–	–	–	–

Table N-41. Integration Strategy 7 Annualized Cost and Volumes: Moloka'i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	–	–	$255
Distribution Transformer	$114	$125	–	$239
Overhead Conductor	–	–	–	–
Underground Conductor	–	–	–	–
Substation Transformer	–	–	–	–
Grand Total	*$369*	*$125*	–	*$493*
Voltage Regulators (qty)	6	–	–	6
Distribution Transformer (qty)	10	10	–	20
Overhead Conductor (feet)	–	–	–	–
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	–	–	–

Table N-42. Integration Strategy 1 Annualized Cost and Volumes: Lana‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$3,954	$275	$815	$5,043
Replacement BESS	–	$2,569	$2,868	$5,438
Var Compensation Devices	$107	$133	$250	$490
DER Controls	$28	$26	$89	$143
Grand Total	*$4,089*	*$3,003*	*$4,022*	*$11,114*
BESS (kW)	1,010	104	355	1,470
BESS (kWh)	4,042	418	1,422	5,881
Replacement BESS (kW)	–	1,010	1,244	2,255
Replacement BESS (kWh)	–	4,042	4,976	9,018
Var Compensation Devices (kW)	123	131	197	451

Table N-43. Integration Strategy 2 Annualized Cost and Volumes: Lana‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$168	–	–	$168
Var Compensation Devices	$36	$133	$250	$419
DER Controls	$28	$26	$89	$143
Grand Total	*$232*	*$159*	*$339*	*$730*
Voltage Regulators (qty)	4	–	–	4
Var Compensation Devices (kW)	123	131	197	451

Table N-44. Integration Strategy 3 Annualized Cost and Volumes: Lana‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	$158	–	$412
Distribution Transformer	$742	$869	–	$1,610
Overhead Conductor	–	–	–	–
Underground Conductor	–	–	–	–
Substation Transformer	–	–	–	–
Grand Total	*$996*	*$1,026*	–	*$2,023*
Voltage Regulators (qty)	6	3	–	9
Distribution Transformer (qty)	37	37	–	73
Overhead Conductor (feet)	–	–	–	–
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	–	–	–

Table N-45. Integration Strategy 4 Annualized Cost and Volumes: Lana‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$255	$158	–	$412
Distribution Transformer	$742	$869	–	$1,610
Overhead Conductor	–	–	–	–
Underground Conductor	–	–	–	–
Substation Transformer	–	–	–	–
DER Controls	$73	$849	$133	$1,055
Grand Total	*$1,069*	*$1,875*	*$133*	*$3,077*
Voltage Regulators (qty)	6	3	–	9
Distribution Transformer (qty)	37	37	–	73
Overhead Conductor (feet)	–	–	–	–
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	–	–	–

Table N-46. Integration Strategy 5 Annualized Cost and Volumes: Lana‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$1,262	$4,962	$1,268	$7,492
Replacement BESS	–	$850	$8,062	$8,911
Var Compensation Devices	$17	$143	$17	$177
DER Controls	$73	$849	$133	$1,055
Grand Total	*$1,352*	*$6,804*	*$9,479*	*$17,635*
BESS (kW)	337	1,923	532	2,791
BESS (kWh)	1,348	7,690	2,127	11,165
Replacement BESS (kW)	–	337	3,512	3,849
Replacement BESS (kWh)	–	1,348	14,049	15,396
Var Compensation Devices (kW)	19	137	15	171

Table N-47. Integration Strategy 6 Annualized Cost and Volumes: Lana‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$168	$158	–	$326
Var Compensation Devices	$10	$143	$17	$170
BESS	–	–	–	–
Replacement BESS	–	–	–	–
DER Controls	$73	$849	$133	$1,055
Grand Total	*$251*	*$1,149*	*$150*	*$1,551*
Voltage Regulators (qty)	4	–	–	4
Var Compensation Devices (kW)	19	137	15	171
BESS (kW)	–	–	–	–
BESS (kWh)	–	–	–	–
Replacement BESS (kW)	–	–	–	–
Replacement BESS (kWh)	–	–	–	–

Table N-48. Integration Strategy 7 Annualized Cost and Volumes: Lana‘i

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$5,054	$7,527	$5,375	$17,956
Distribution Transformer	$3,908	$1,792	$1,413	$7,113
Overhead Conductor	–	–	–	–
Underground Conductor	–	–	–	–
Substation Transformer	–	–	–	–
Grand Total	*$8,963*	*$9,320*	*$6,787*	*$25,069*
Voltage Regulators (qty)	72	94	54	220
Distribution Transformer (qty)	318	126	85	529
Overhead Conductor (feet)	–	–	–	–
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	–	–	–

Table N-49. Integration Strategy 1 Annualized Cost and Volumes: Hawai'i Island

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$32,177	$9,048	$6,975	$48,200
Replacement BESS	–	$21,656	$11,781	$33,437
Var Compensation Devices	$57	–	$258	$315
DER Controls	$2,589	$4,694	$11,144	$18,426
Grand Total	*$34,822*	*$35,398*	*$30,158*	*$100,378*
BESS (kW)	8,586	3,439	2,991	15,016
BESS (kWh)	34,344	13,756	11,964	60,064
Replacement BESS (kW)	–	8,586	5,105	–
Replacement BESS (kWh)	–	34,344	20,420	54,764
Var Compensation Devices (kW)	63	–	230	293

Table N-50. Integration Strategy 2 Annualized Cost and Volumes: Hawai'i Island

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$3,472	–	–	$3,472
Var Compensation Devices	$57	–	$258	$315
DER Controls	$2,589	$4,694	$11,144	$18,426
Grand Total	$6,117	$4,694	$11,402	$22,213
Voltage Regulators (qty)	50	–	–	50
Var Compensation Devices (kW)	63	–	230	293

Table N-51. Integration Strategy 3 Annualized Cost and Volumes: Hawai'i Island

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$14,327	$2,107	$760	$17,194
Distribution Transformer	$1,397	$2,737	$161	$4,295
Overhead Conductor	$1,803	$1,492	–	$3,295
Underground Conductor	–	–	–	–
Substation Transformer	$4,109	$38,258	$51,456	$93,823
Grand Total	*$21,635*	*$44,594*	*$52,377*	*$118,607*
Voltage Regulators (qty)	191	25	8	224
Distribution Transformer (qty)	115	195	10	320
Overhead Conductor (feet)	24,159	17,652	–	41,811
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	4	26	31	61

Table N-52. Integration Strategy 4 Annualized Cost and Volumes: Hawai'i Island

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$14,327	$2,107	$760	$17,194
Distribution Transformer	$1,397	$2,737	$161	$4,295
Overhead Conductor	$1,803	$1,492	–	$3,295
Underground Conductor	–	–	–	–
Substation Transformer	–	$8,794	$21,176	$29,970
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$21,890*	*$55,142*	*$51,326*	*$128,358*
Voltage Regulators (qty)	191	25	8	224
Distribution Transformer (qty)	115	195	10	320
Overhead Conductor (feet)	24,159	17,652	–	41,811
Underground Conductor (feet)	–	–	–	–
Substation Transformer (qty)	–	6	14	20

Table N-53. Integration Strategy 5 Annualized Cost and Volumes: Hawai'i Island

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
BESS	$33,076	$187,013	$178,911	$398,999
Replacement BESS	–	$23,280	$254,356	$277,636
Var Compensation Devices	$1,130	$94	–	$1,224
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$38,570*	*$250,398*	*$462,495*	*$751,463*
BESS (kW)	9,334	72,449	76,950	158,733
BESS (kWh)	37,336	289,796	307,800	634,932
Replacement BESS (kW)	–	9,334	110,713	120,047
Replacement BESS (kWh)	–	37,336	442,852	480,188
Var Compensation Devices (kW)	1,276	93	–	1,370

Table N-54. Integration Strategy 6 Annualized Cost and Volumes: Hawai‘i Island

Upgrade [Nominal $000]	2016–2020	2021–2030	2031–2045	Total
Voltage Regulators	$12,675	–	–	$12,675
Substation Transformer	$4,109	–	–	$4,109
Var Compensation Devices	$742	$94	–	$836
BESS	–	$24,735	$46,802	$71,537
Replacement BESS	–	–	$41,189	$41,189
Overhead Conductor	$1,803	$1,492	–	$3,295
DER Controls	$4,364	$40,012	$29,229	$73,604
Grand Total	*$23,692*	*$66,334*	*$117,219*	*$207,244*
Voltage Regulators (qty)	168	–	–	168
Substation Transformer (qty)	4	–	–	4
Var Compensation Devices (kW)	1,276	93	–	1,370
BESS (kW)	–	9,732	20,318	30,050
BESS (kWh)	–	38,928	81,272	120,200
Replacement BESS (kW)	–	–	18,030	18,030
Replacement BESS (kWh)	–	–	72,120	72,120
Overhead Conductor (feet)	24,159	17,652	–	41,811

Table N-55. Integration Strategy 7 Annualized Cost and Volume: Hawai‘i Island

O. System Security Analysis

System security (or Operating Reliability) is defined by NERC as *the ability of the system to withstand sudden disturbances*.[1] These disturbances or contingencies can be the loss of generation or electrical faults that can cause sudden changes to frequency, voltage and current. Operating equilibrium following these disturbances must be restored to prevent damage to utility and end-use equipment, and to ensure public safety.

TRANSMISSION SYSTEM FUNDAMENTALS

System security or system stability in an electric power system is the attribute of the system, or its components, to regain a state of operating equilibrium after being subjected to disturbing forces (transient events), such that the majority of the system remains intact. Stability of a power system can be characterized by frequency stability, voltage stability, and rotor angle stability.

The electrical transmission system is designed to deliver power from central station generators to distribution load centers while optimizing efficiency and maintaining a high level of reliability. The transmission system is the backbone of the electrical infrastructure and its design is based on the inherent characteristics of synchronous generators.

A synchronous generator is essentially a large rotating electro-magnet that converts mechanical energy to three-phase electrical energy that is transferred to the electrical system through a rotating magnetic field. All synchronous generators are directly tied to each other through this magnetic field. An electrical system with more synchronous

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1 NERC, *Definition of "Adequate Level of Reliability"*, December 2007, http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

generators (like the Western Electricity Coordinating Council) has a high inertia and a strong magnetic coupling, making it less susceptible to disruptions from disturbances like a generator trip or electrical fault.

Synchronous generators develop balanced, three-phase current in their armature windings with each phase separated by 120°. Generator terminal voltage is increased to higher voltages (for example, 138 kV) to efficiently transfer energy over long transmission lines. Heating losses in a conductor is proportional to the square of the current so increasing voltage by a factor of 10 reduces heat losses by a factor of 100.

Distribution substations reduce the transmission voltage through a step-down transformer so power can be delivered to customers. Distribution circuits attempt balance customer loads maintain this balanced three-phase system to maintain tariff requirements for power quality and ensure system reliability. The challenge is to maintain this balanced three-phase system while integrating high capacities of single-phase DG-PV and demand response resources.

Minimum Fault Current

Electrical faults are the most severe disturbance that can cause extensive damage to equipment and pose a safety risk to the public. Protective relay schemes are designed to locate and isolate these faults within cycles to ensure equipment protection and maintain system reliability. If the system fault current is insufficient, protective relays cannot detect and isolate the faulted element as designed. Downed transmission lines that cannot be isolated appear as a large system load, causing localized "brown-outs" that poses a safety risk to the public and equipment.

Maintaining a minimum level of fault current ensures protective relays will operate. It does not ensure transient voltage stability. An electrical system with a high capacity of fault current is less susceptible to disruptions from electrical faults. Systems with a high fault current capacity are also less susceptible to the adverse effects of harmonic currents. Fault current capacity is supplied by the mega volt-ampere (MVA) capacity of synchronous machines (generators, synchronous condensers, and induction motors).

System Grounding

System grounding is also a fundamental requirement for system security. Unit commitment schedules will have an impact on the available grounding sources on the 138 kV system.

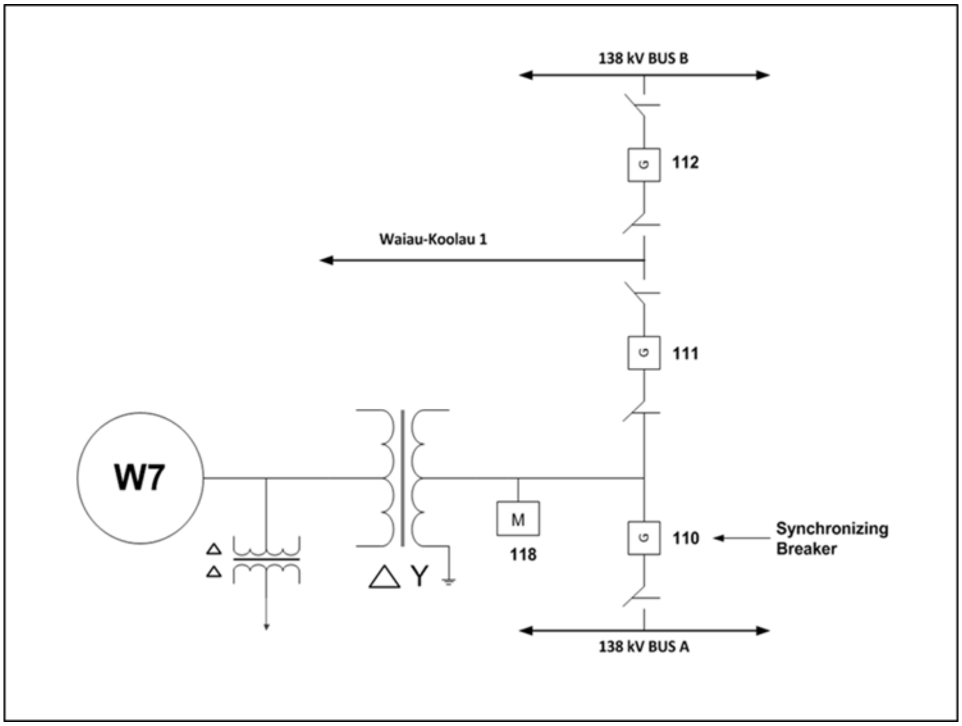

Figure O-1. Grounding Scheme 138 kV System

Figure O-1 shows the single line diagram for Waiau Unit 7 which is typical of all steam units that have synchronizing breakers on the high-side of the step-up transformer. When steam units are cycled offline or decommissioned, the 138 kV grounding source is isolated from the system. The integrity of the 138 kV grounding system must be evaluated in conjunction with the protection coordination study to ensure system security.

System Stability

Whereas previous system security analyses focused on system requirements for frequency stability, this analysis was expanded to determine voltage stability requirements for each resource plan.

Rotor angle stability is an important aspect of system security but this requires unit-specific modeling data like transmission line impedance, generator characteristics (H-constant, synchronous/sub synchronous/transient reactance), exciter characteristics, etc. Given the detailed modeling requirements, rotor angle stability analysis is not feasible for long range planning studies. Rotor angle stability analysis is typically performed as part of the interconnection requirement study for a new facility.

Frequency Stability

Frequency stability is maintained when real power supply is equal to system demand under steady state and dynamic conditions. Frequency instability may occur as a result of a significant loss of generation or load, such that system reserves or protective schemes are unable to return the system to operating equilibrium.

Synchronous generators provide frequency response that is proportional to the magnitude of the contingency event. This includes rotational inertia, that resists changes to rotor speed due to the mass of the turbine-generator rotor; and governor response or primary reserves, that is a reactive, proportional control response to changes in rotor speed. This concept of proportional response is very important as we integrate demand response into the system's frequency response reserves. Over compensation for a loss of generation contingency could drive frequency above 60.5 Hz and cause a subsequent contingency event. The capacity of legacy PV that will disconnect from the system at 60.5 Hz is significantly higher than the capacity that disconnects at 59.3 Hz.

Currently, each island is challenged with maintaining frequency stability on the system. The proliferation of DG-PV has helped the State meet RPS target but at the same time has displaced synchronous generation. Loss of generation on a system with low inertia results in a high rate of change of frequency (RoCoF), making it difficult for traditional governor response to arrest frequency decay.

Voltage Stability

Voltage stability is the ability of a power system to maintain voltages at all buses within specified limits after being subjected to a disturbance from a given initial operating condition, restoring the system to operating equilibrium.

Voltage issues are typically location specific and is a function of loading of the area or bus. Therefore, voltage stability is examined for boundary conditions that represent the highest peak demand for any given year.

The methodology to determine voltage stability included several different steady-state and transient analyses. These include the following:

PV Analysis

The PV analysis is one of the most widely performed analysis to determine the real power transfer capability of the transmission system; and to the determine the active power margin before the point of voltage instability. Multiple power flow simulations are performed for increasing loads while monitoring system voltage.

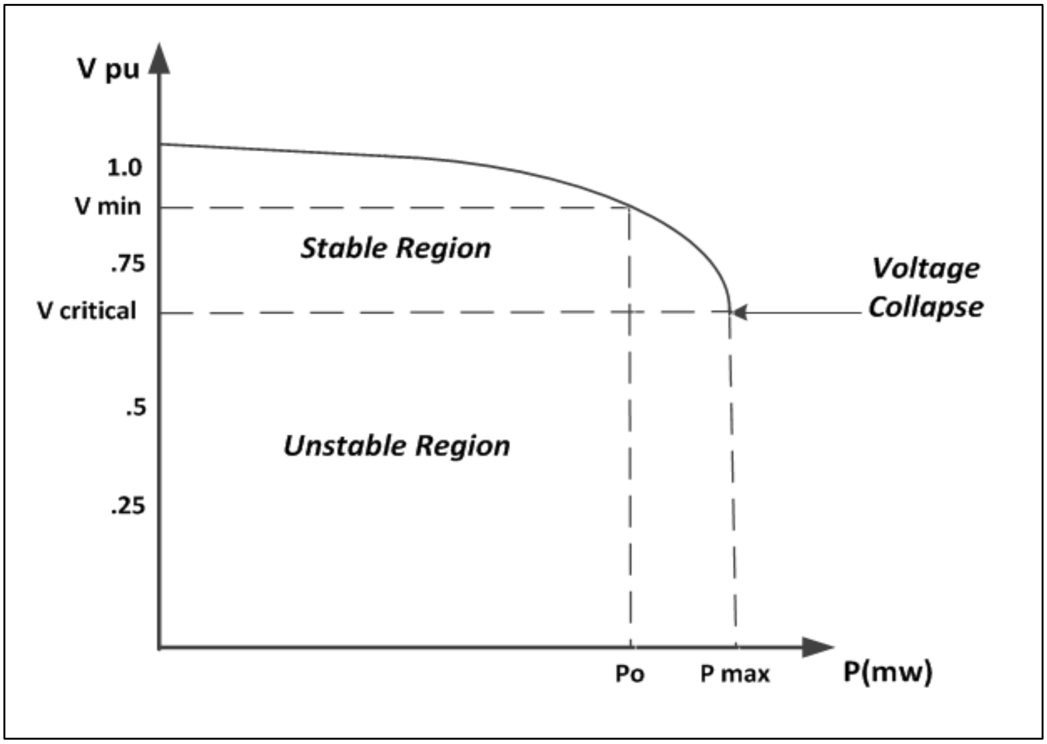

Figure O-2. PV Curve

Figure O-2 shows a typical PV curve. As power flow or load increases, bus voltage begins to decrease until the system reaches the stability limit at *Pmax*. Any increase in load will cause voltage collapse at the bus.

QV Analysis

The QV analysis determines the MVAR requirements of the system to maintain voltage stability under steady state and transient conditions. Critical busses have the lowest per-unit voltage under steady state and post-transient conditions and are selected based on historical data. Therefore, meeting the MVAR requirements for these busses ensures reactive power requirements for the entire electrical system are met.

The QV curve is obtained by plotting the results of a series of power flow simulations where the voltage at the bus of interest is sequentially anchored and the MVARs required to maintain that bus to the anchored voltage is determined. The analysis is performed for a range of per-unit voltages and results plotted to develop the QV curve. A good starting point is bus voltages from 1.0 to 0.85 per unit, anchored in steps of 0.10 per unit.

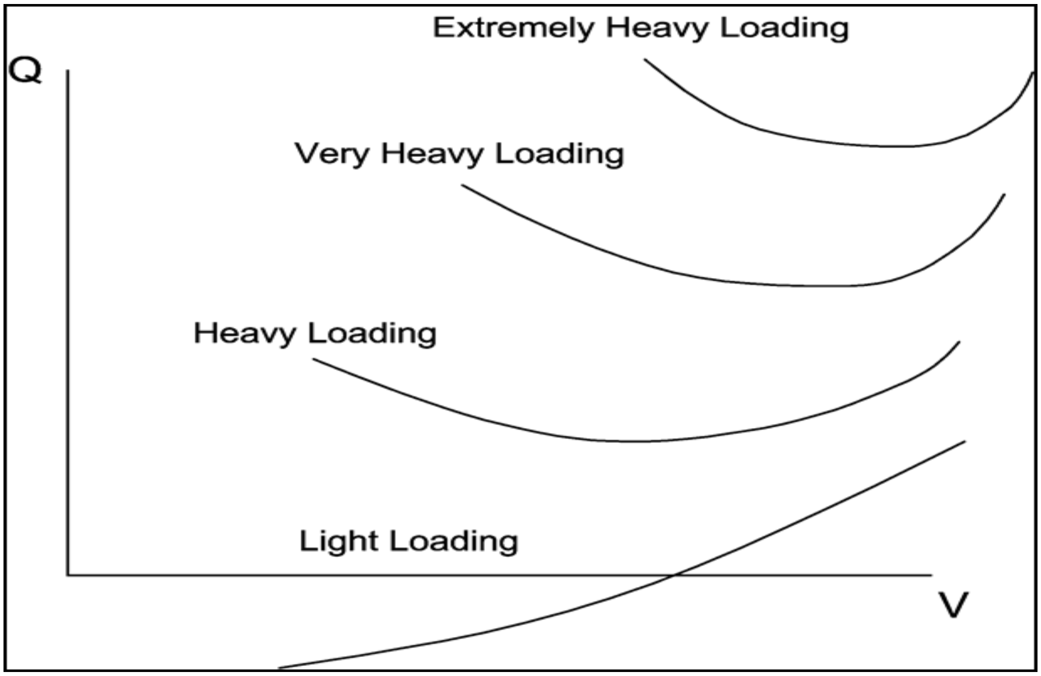

Figure O-3. Family of QV Curves

Figure O-3 shows a family of QV curves at various bus loads. The QV curves at higher loads tend to be parabolic. The bus is stable when the injection of MVARs results in an increase in voltage and unstable at the bottom of the QV curve, where the derivative dQ/dV is equal to zero for the bus under evaluation. In addition to identifying the stability limit of the bus, the bottom of the QV curve defines the minimum reactive power requirement for stable operation. Hence, the QV curve can be used to examine the type and size of compensation needed to provide voltage stability.

Busses having QV curves below the horizontal voltage axis have a positive reactive power margin. The system may still be called reactive power deficient, depending on the desired margin.

Short Circuit Ratio

There is currently no industry-standard approach to calculate the proper short circuit ratio (SCR) index for a weak system with a high penetration of inverter-based generation. To take into account the effect of interactions between wind plants and give a better estimate of the system strength, a more appropriate quantity is the weighted short circuit ratio (WSCR)[2], defined by:

[2] Electranix, System Strength Assessment of the Panhandle System, Electric Reliability Council of Texas, 2016

$$WSCR = \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{(\sum_{i}^{N} P_{RMWi})^2}$$

Where S_{SCMVAi} is the short circuit capacity at bus i and P_{RMWi} is the MW rating of the wind plant; N is the number of total wind plants fully interacting with each other and i is the wind plant index. For the purposes of this PSIP analysis, wind plants are replaced with DG-PV capacities.

Several system characteristics and challenges that can occur in a weak grid are:

- In a highly compensated weak grid, voltage collapse can occur within the normal operating voltage range (0.95 to 1.05 PU) masking voltage stability risks in real time operations. Static capacitor and static VAR compensators contribute to this effect and have limited effectiveness for further increasing transfer capability.
- A grid with low short circuit ratios and high voltage sensitivity of dV/dQ requires special coordination of various complex control systems. Typical voltage control settings can result in aggressive voltage support in a weak system and lead to un-damped oscillations, overvoltage cascading or voltage collapse.
- Inverter-based generation connected to a common point of interconnection (POI) may interact with other facilities.

Short circuit ratio analyses will not be performed for this PSIP filing. There is no industry standard that specifies a minimum SCR and specific issues should be evaluated with detailed user models of inverter-based generation at specific bus locations.

Voltage stability analysis for this filing will focus on QV analysis for the near-term Action Plan years through 2021.

Rotor Angle Stability

Rotor angle stability is not part of this system security analysis but is a critical aspect of system security. Rotor angle instability occurs when there is a loss of synchronism of a generator or generator pole slipping.

Special consideration must to given to rotor angle stability because of the potential severe consequences of generator pole-slipping. When a close-in electrical fault cannot be cleared within the critical clearing time of the generator, the magnetic link between the generator and the electrical system is broken, causing loss of synchronism. Consequences can range from no damage to catastrophic failure of both the generator and turbine.

The most severe transient stability incident is the electrical fault that is close to a generating station. Figure O-4 describes what happens when an electrical fault occurs at the generating station bus. Three power angle curves depict pre-fault, during-fault, and post-fault conditions for both stable and unstable operation. The Equal Area Criterion states that kinetic energy that is added to the rotor following a fault must be removed from the rotor after the fault to restore the rotor to synchronous speed. This means that the faulted transmission element must be removed to allow power flow to the system, removing the kinetic energy that was added to the rotor.

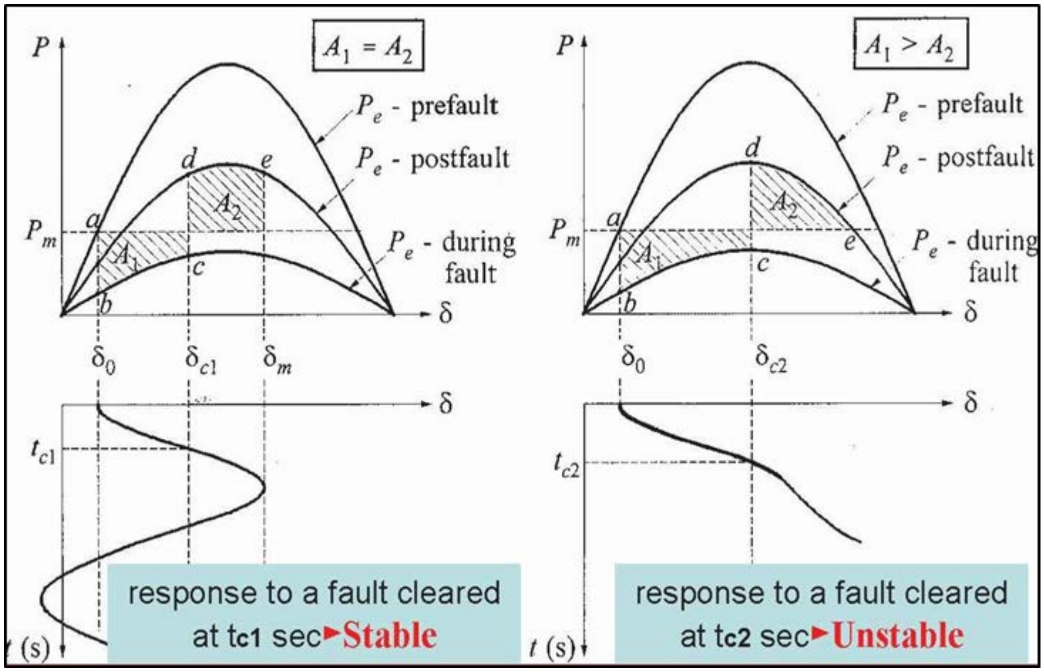

Figure O-4. Equal Area Criterion for Stability

Refer to the power curve plots in the upper left of Figure O-4. The system is operating at "*Point a*" on the "*Pe*-pre-fault" power curve. When the fault occurs, generator terminal voltage will suddenly decrease so there is a drastic decrease in electrical power delivered to the system. The reduction in power delivered to the system is represented by the new power curve "*Pe* – during-fault". The mechanical power remains constant since governor response cannot operate in this timeframe (cycles) and system inertia prevents the power angle δ_0 from changing instantaneously so the system operating point drops to "*Point b*" on the "*Pe* – during fault" curve. Conservation of energy transforms the mechanical energy to kinetic energy so the rotor begins to accelerate (the lower left plot) and the system operating point moves along the "*Pe* – during-fault" power curve to "*Point **c***" at which time the fault is cleared at t_{c1}. The power angle when the fault is cleared is δ_{c1}.

When the fault clears, generator terminal voltage increases and more power can be delivered to the system. This is depicted by "*Point d*" on the new power angle curve, "*Pe* - post-fault". At this point, kinetic energy that was added to the rotor can be removed (transferred to the system) and the operating point moves to "*Point e*". Note that the rotor continues to accelerate due to inertia and the rotor angle increases until it reaches its maximum rotor angle δ_m. At this time, the rotor angle exhibits a dampening effect as it approaches a state of equilibrium. The fault was cleared in sufficient time to remove the kinetic energy from the rotor and the Equal Area Criteria for stability is met, that is, Area A1 = Area A2.

A similar sequence of events occurs for the power angle curve in the upper right of Figure O-4 except the Equal Area Criteria is not met and the rotor loses synchronism with the system. The electrical fault is cleared at t_{c2}, after the critical clearing time of the rotor. The kinetic energy added to the rotor could not be removed to restore the rotor to synchronism, Area A1 > Area A2.

A system with more synchronous generators has a stronger magnetic coupling, making it more difficult for generators to lose synchronism. In addition, synchronous generators with more rotational inertia (high H-constants) have longer critical clearing times and are better suited to withstand close-in electrical faults. Another factor is the ability of the protective relay system to quickly isolate the faulted element to maintain rotor stability.

Maintaining System Security

The transmission planning criteria establishes the design requirements to safely deliver real and reactive power to the distribution system. These criteria require the planning engineer to design mitigation measures to ensure system security is maintained for normal operation, planned contingency events, and cascading contingency events.

Some fundamental design philosophies to ensure system security include the following:

- Limit the magnitude of the contingency (for example, limit the rating of single loss of generation contingency)
- Design requirements of transmission network components (breaker-and-a-half schemes for generating units, redundant transmission lines, multiple transmission corridors, etc.
- Design requirements of synchronous generators (high inertia constants, high short-circuit ratio, excitation systems that are independent of system voltage, reserve capacity, etc.)
- Protective relay schemes to ensure public safety and protect equipment
- Under frequency and under voltage load shed schemes to prevent system collapse

Operational strategies to maintain system security include:

- Commit sufficient synchronous generators and/or synchronous condensers machines to provide inertia for frequency stability; and short circuit current capacity for voltage stability

- Limit the magnitude of the contingency and maintaining adequate contingency reserves are operational strategies implemented by the system operator to maintain system reliability
- Commit units or implement load shifting strategies to mitigate system risk due to transmission line maintenance

SYSTEM SECURITY ANALYSIS

Resource planning must incorporate fundamental system security parameters because online resources can affect both the magnitude of the disturbance and the ability of the system to respond. For example, the size of the largest resource on the system defines the largest contingency that must be protected against, and the characteristics of available resources determine the system response. This is why generating units in Hawai'i are designed to be smaller that units in the mainland. The down side is that generating resources cannot take advantage of economy of scale to lower cost.

Island systems have a fixed load so integration of wind and solar resources displaces traditional synchronous generators. This reduces system inertia, system short-circuit current, and the overall magnetic strength of the electrical system; thus affecting all aspects of system security (that is, frequency stability, voltage stability, and rotor angle stability).

Currently, thermal generators are required to provide all of the system security attributes but at some point in time, technology-neutral resources will be available in sufficient capacities to augment and/or replace thermal generators. Each candidate resource plan is analyzed to determine technology-neutral system security requirements to meet TPL-001.

Technology-neutral requirements can be determined for frequency response reserves but short circuit current for protective relay schemes and voltage stability can only be provided by synchronous machines. Therefore, resource plans are analyzed to determine if online generators are sufficient to meet minimum short circuit current requirements and if not, synchronous condensers are added to augment thermal unit commitment schedules. Synchronous condensers also provide reactive power capacity and voltage regulation. Therefore, alternatives for these resources like capacitor banks, static VAR compensators, or dynamic VAR compensators were not considered in these analyses.

Reliability Criteria

The HI-TPL-001, along with Transmission Planning Criteria establishes the reliability criteria for each island. For O‘ahu, HI-TPL-001 was revised to no UFLS for single generator contingency events while Maui and Hawai‘i Island allow 15% system load. With no UFLS for single contingency events, O‘ahu is able to leverage DER resources to provide PFR. For Maui and Hawai‘i Island, PFR must be connected to the transmission or sub-transmission systems since DER may be part of the 15% system load shed.

The electrical systems on Moloka‘i and Lana‘i grids are unique radial distribution systems (12kV) that do not fall under the jurisdiction of HI-TPL-001. Therefore, the reliability criterion is to maintain the status quo, if possible, or prevent total system collapse.

Under-frequency load shedding (UFLS) is a means to restore system frequency to operating equilibrium for various loss of generation contingency events. Ultimately, it is the last line of defense of system security to prevent system blackouts but it has shortcomings for future conditions in Hawai‘i. Under high levels of distributed PV generation, the residential load net of PV is reduced so UFLS schemes are compromised. Instead of disconnecting distribution circuits, future UFLS schemes must incorporate a more surgical (behind-the-meter) residential load shedding scheme or resort to commercial sector load shedding to ensure system security.

In addition to TPL-001, the Transmission Planning Criteria determined the fundamental design of each island's transmission system to ensure distribution systems meet voltages tariff requirements for power quality. For O‘ahu, bus voltages throughout the system must remain above 0.92 PU for N-2 contingencies. For Maui and Hawai‘i Island, bus voltages must remain above 0.90 PU for N-1 contingencies.

How System Security is Typically Maintained

The transmission planning criteria establishes the design requirements to safely deliver real and reactive power to the distribution system. These criteria require the planning engineer to design mitigation measures to ensure system security is maintained for planned and contingency events. Some fundamental design philosophies to ensure system security include the following:

- Redundant transmission lines for capacity transfer and contingencies
- Transmission network/spatial integrity of transmission corridors
- Breaker-and- a- half or ring-bus schemes for generating units
- Limit the magnitude of the contingency

- Design requirements of synchronous generators (high inertia constants, high short-circuit ratio, excitation systems that are independent of system voltage, reserve capacity, etc.)
- Protective relay schemes to ensure public safety and protect equipment
- Under frequency load shed schemes to prevent system collapse and reduce restoration times

System security is maintained by operating the system with sufficient inertia, limiting the magnitude of the contingency event, maintaining adequate contingency reserves and maintaining system fault current; at times requiring the system operator to sacrifice efficiency for reliability.

Inertia: the electrical system includes many rotating components which have inertia, including traditional synchronous generators (large rotating electromagnets coupled to heavy turbines or internal combustion engines), and rotating customer loads (usually induction electrical motors connected to appliances, pumps). During a contingency, the inertia in these rotating mass will resist changes to their rotational speed (that is, limit the rate of change of frequency). Inertia, along with droop response, also provides the dampening characteristic to the frequency response profile following a contingency event as a synchronous generator continuously resists change to its rotational speed. Hence, an electrical system with high inertia is more robust and can withstand contingency events better than a low inertia system.

Operational actions to protect against contingencies: 1) limit the magnitude of the disturbance; 2) reconfigure the system to mitigate risks; and 3) ensure the system is carrying the necessary contingency reserves to mitigate the adverse effects of these contingency events.

Fault protection: synchronous generators provide sufficient system fault current to activate protective relay schemes within the critical clearing times of transmission lines and generators. System fault current is also required to ensure protective relay schemes at the distribution system can detect and isolate downed power lines to ensure public safety and prevent equipment damage. Also note that an electrical system with a high capacity of fault current is less susceptible to the adverse effects of harmonic currents.

How System Security Relates to This PSIP

Resource planning must incorporate fundamental system security parameters because online resources can affect both the magnitude of the disturbance and the ability of the system to respond. For example, the size of the largest resource on the system defines the largest contingency that must be protected against, and the characteristics of available resources determine the system response.

For island systems with very high levels of wind and solar resources, the most critical security concern is displacement of thermal generators, reducing system inertia and the available system fault current.[3] This concern dominates because (a) the largest loss of generation contingency becomes a larger percentage of the total supply; (b) the large contingency on the low inertia system will require multiple blocks of under frequency load shed (UFLS) to stabilize system frequency; and (c) displacement of synchronous generators reduce the magnetic strength of the system.

System security considerations are incorporated into this PSIP plan in a supportive role and do not constrain the candidate resource plans beyond limiting the magnitude of the contingency as stated above. Currently, thermal generators provide the necessary system security attributes but at some point in time, technology-neutral resources will be available in sufficient capacities to augment and replace these attributes.

Each candidate resource plan is analyzed to determine system security requirements to 1) meet the reactive power requirement of the system, and 2) meet the requirements of TPL-001. Frequency response reserve capacities are determined for each resource plan in technology-neutral capacities and reactive power requirements are met by synchronous condensers.

APPROACH TO ANALYZING SYSTEM SECURITY IN THIS PSIP

The process of identifying needs and designing solutions follows a several-step process that we believe addresses the Commission's concerns regarding the prior PSIP filing. (Note that this process was outlined as six steps in the Companies' February 2016 filing. The revised process is equivalent, but reorganized to complement the rest of the PSIP more clearly.)

The five steps are:

- Establish operational reliability criteria.
- Define technology-neutral ancillary services for meeting reliability criteria.
- Determine system requirements to support the resource plan.
- Find the lowest reasonable cost solution, considering all types of qualified resources.
- Identify flexible planning and future analyses to optimize over time.

[3] Low short-circuit current also affects transient voltage stability and harmonics.

Step 1: Establish Reliability Criteria

Two documents establish the reliability criteria for this system security analysis. In addition to TPL-001, O‘ahu, Maui, and Hawai‘i have Transmission Planning Criteria that established the foundational design of each island's transmission system.

For O‘ahu, TPL-001 was revised to no UFLS for single generator contingency events while Maui and Hawai‘i Island allow 15% system load. The Moloka‘i and Lana‘i systems are nominal 34.5/12 kV radial distribution systems that do not fall under the jurisdiction of TPL-001. The reliability criteria for these system is to maintain an acceptable margin of stability to ensure public safety and meet tariff obligations for power quality.

Step 2: Define Technology-Neutral Requirements for Meeting Reliability Criteria

The fundamental system security requirements can be defined by segregating the frequency response characteristics inherent to synchronous generators. These include the following:

Inertia is required to resist changes to the rotational speed of generators. A system with higher inertia is less susceptible to disruption due to disturbance cause by an imbalance of generation and load; and is more likely to regain a state of operating equilibrium. Inertial response is proportional to the magnitude of the contingency and is specified in MW-sec or Megajoules.

Primary frequency response (turbine governor or droop response) is required to reduce the rate-of-change of frequency and stabilize system frequency (obtain a state of operating equilibrium) following a generation to load imbalance. Primary frequency response is proportional to the magnitude of the contingency and is specified in a MW capacity for a given droop response (e.g. 5%).

Fault current or short circuit current capacity is determined by the capacity of synchronous generating units and to some extent, induction motors. Analogous to inertia and frequency, a system with higher fault current is less susceptible to disruption due to disturbances due to electrical faults. For this analysis, minimum fault current capacity required to operate protective relays does not ensure transient voltage stability of the system. Fault current is specified in MVA and is supplied by synchronous generators or synchronous condensers.

Reactive power provides the energy to magnetize the system, e.g. transformer windings, inductive circuits and coils, motor stator windings, conductor losses, etc. Reactive power is specified in MVAR and is supplied by synchronous generators and synchronous condensers.

Fast frequency response is an ancillary service product and is not an inherent characteristic of synchronous generators. Fast frequency response limits the rate-of-change of frequency, providing more time for primary frequency response to stabilize system frequency.

Table O-1 presents the frequency response services proposed for Hawai‘i, along with technical specifications that any resource type would have to meet in order to provide that service.

Frequency Response: Services		
Examples of Suitable Resources	*Equipment Requirements*	*Performance Requirements*
Inertia	Resist changes to rotational speed of synchronous units	
■ Synchronous generators (including pumped storage) and flywheels ■ Synchronous motor loads also provide inertia; Hawaiian Electric may plan around them but wouldn't procure or control them ■ Synchronous condensers	■ Spinning mass electromagnetically coupled to grid	■ Natural characteristics of synchronous generators ■ Proportional response to changes in speed
Primary Frequency Reserves (PFR)	Stabilize frequency in either direction w/response proportional to changes in speed or frequency	
■ Synchronous generators ■ Inverter-interfaced generators and storage	■ Governor or control system meeting minimum performance requirements for droop and deadband	■ Initiation governed by deadband less than ± 1Hz ■ Linear response to changes in speed or frequency ■ Time to max: a few seconds (for example, 16 seconds in ERCOT FAS) ■ Duration: TBD based on Replacement response time
Fast Frequency Reserves 1 (FFR1)	Reduce the rate of change of frequency w/response proportional to the generation contingency	
■ Very fast-response resources (likely central station), such as batteries, flywheels, and curtailed PV	■ Control system capable of responding to signals within specified response time ■ 2-way real-time communications	■ Trigger: signal from large trip or df/dt ■ Initiation time and time to max: several cycles (for example, 12 cycles total reaction time) ■ Duration: TBD based on Replacement response time and resource capabilities (for example, 10 minutes in ERCOT; 30 minute in Hawai‘i Electric Light to allow replacement by gas turbine.)
Fast Frequency Reserves 2 (FFR2)	Reduce the rate of change of frequency w/response that is independent of generation contingency	
■ Distributed resources w/autonomous control, including DR from fairly constant loads that can curtail nearly instantaneously	■ Under-frequency relays that can respond within specified response time ■ 1-way real-time communication (user to operator) to allow operator to measure how much load is available to curtail	■ Trigger: 59.7 Hz ■ Initiation time (and time to max): a fraction of a second ■ Duration: TBD based on Replacement response time and DR capabilities (for example, 1 hour in ERCOT FAS)

Table O-1. Frequency Response: Services

Step 3: Determine System Requirements to Support the Resource Plans

System security requirement vary with each resource plan vary by island, resource strategy, and time period. That is because Frequency Response needs are driven by the size of the largest contingency, which is generally the largest unit online at the time. Regulation needs are driven by the variability of net load (that is, load minus renewable generation output), which depends especially on the amount of PV and wind. And Replacement reserve needs are driven by the amounts of Frequency Response and Regulation needed.

Reactive Power Requirements. QV analyses were performed on critical busses to determine if the resource plans meet the reactive power requirements of the system to ensure voltage stability. The QV analysis was performed for N-2 transmission contingencies for O‘ahu, and N-1 transmission contingencies for Maui and Hawai‘i Island.

Frequency Response Requirements. Our analytical methodology for determining the necessary amounts of Frequency Response services builds upon the FFR analyses performed in the Integrated Demand Response Portfolio Plan Supplement: System Response Requirements dated November 6, 2015 (Docket No. 2007-0341). In this PSIP, Fast Frequency Reserve requirements are determined for selected years for each candidate resource plan, under a range of system inertia, system load, and PFR for the largest contingency. The specific modeling approach and key assumptions are described in the next section of this appendix.

Minimum Fault-Current. Electrical faults are the most severe disturbance that can cause extensive damage to equipment and pose a safety risk to the public. Protective relay schemes are designed to locate and isolate these faults within cycles to ensure equipment protection and maintain system reliability. However, if the system fault current is insufficient, protective relays cannot detect and isolate the faulted element as designed. Downed transmission lines that cannot be isolated appear as a large system load, causing localized “brown-outs” could trigger extensive UFLS. This also poses a safety risk to both equipment and the public.

Simulations were performed in the April PSIP to determine the MVA capacity required to meet minimum fault current levels for three phase, line-to-line, and single line to ground faults are established for each substation 46kV bus to ensure proper operation of protective relay schemes.

For the Maui and Hawai‘i Island systems, the minimum fault current requirements at the distribution substations have not been determined. Therefore, the MVA capacities provided by the current must-run thermal units will be maintained.

Step 4: Find Lowest Reasonable Cost Solution Considering All Types of Qualified Resources

All of the Ancillary Service needs are defined in technology-neutral terms so any qualified resource can meet them, whether traditional generation, advanced features of inverter-interfaced generation and storage, or demand response. Our objective is to identify the lowest reasonable cost combination that ensures system security for a given resource plan and in subsequent iterations, let the market and specific resource applications determine available resources. To do so, we break the analysis into three steps:

1. Perform analysis on pre-DR resource plans to determine system security requirements;
2. Substitute DR to the full extent it is cost-effective, producing a revised resource strategy;
3. Perform analysis on DR resource plans to determine system security requirements.

As stated earlier, thermal units are required to provide system fault current from 2016 through a period of time when retired units can be converted to synchronous condensers as dictated by the resource plan. To reduce potential curtailment in the interim, fossil fired steam units can operate in in VPO[4] if available.

In the pre-DR solution, we determine what is required to meet HI-TPL-001. We then determine if FFR2 capacities are sufficient and if not, evaluate alternatives to meet system security requirements. This could be to limit the magnitude of the contingency, supplement FFR2 with increased system inertia (operate units in VPO if available), or supplement FFR2 with FFR1.

The initial pre-DR solution meets Regulation needs from the lowest-cost available resources by including regulation as a minimum “spinning reserve” constraint in the dispatch model. If not enough regulation is available, batteries or other resources are added. Note that these needs have already been met before determining Frequency Response needs and solutions.

Once we have a pre-DR solution that meets system security, we determine how much DR can meet the AS technical requirements and cost-effectively substitute for the pre-DR resources.

Finally, after having added DR and other resources to support system security, we assess whether another iteration of system security analysis is warranted. For example, if the amount of synchronous generation decreases substantially, more FFR or system inertia may be needed.

[4] Variable Pressure Operation entails partial burner operation with lower operating pressures. This lowers the operating load at the expense of lower or negligible reserve capacities for dispatch.

Step 5: Identify Flexible Planning and Future Analyses to Optimize Over Time

The PSIP provides a framework to support future decision-making, not a set-in-stone plan. It recognizes the need for flexibility. It recognizes that actual future procurement decisions will incorporate new information and sharpen specific analyses that are not practical or appropriate for the PSIP. But the PSIP can identify ways to maintain flexibility, and future developments to look for, and some of the analyses to conduct when decisions have to be made.

Future analyses may include the following:

- Short circuit ratio analysis to determine the minimum short circuit current required to maintain transient voltage stability.
- Steady state load flow and transient analysis tools to transmit DER to the transmission system
- Damping of oscillatory instabilities for a low-inertia system. Siemens PSS/E is limited to point in time contingency events and is not suited to analyze instability caused by frequency oscillations
- Power quality impacts to the transmission system
- Smart inverter controls and characteristics required to meet system security
- Effects of Rapid Transit in O‘ahu
- Some of these analyses will require modeling tools and/or outside support.

MODELING ANALYSIS

For the April filing, simulations were performed using Siemens PSS/E Version 33.4 software. The generic inverter-based models for these analyses were released in Siemens PSS/E Version 33.7 to facilitate new DG-PV models. System models for each island have been validated against actual events to ensure a high level of confidence in the simulated results for these analyses.

As with any modeling application, each has its benefits and limitations. Siemens PSS/E software is designed to simulate a strong electrical grid, i.e. a grid with a SCR > 3. The issue with violating this criterion is that generic inverter-based generator models may be unstable for both small and large perturbations. These models were developed by WECC for a minimum SCR ≥ 3 at the point of interconnection of the generators. Therefore, what might appear to be an unstable system could be a mathematical problem with the models.

Distributed Generation PV Models

For the April filing, DG-PV was modeled as a negative load on each load bus on the system. This essentially reduced the total net load supplied at the load bus. Two negative load models were created to represent legacy PV inverters and subsequent PV systems with extended ride-through settings. A complete table of the modeled ride-through settings is provided below.

Type	Legacy		Extended	
	Range	Trip (sec)	Range	Trip (sec)
Frequency	-	-	$f > 64$	0.1667
	-	-	$f > 63$	20
	$f > 60.5$	0.157	-	-
	$f < 59.3$	0.157	-	-
	-	-	$f < 57$	20
	-	-	$f < 56$	0.1667
Voltage	V > 1.2	0.157	V > 1.2	0.1667
	V > 1.1	0.99	V > 1.1	0.92
	V < 0.88	1.99	V < 0.88	20
	-	-	V < 0.7	10
	V < 0.5	0.157	V < 0.5	0.5

Table O-2. Negative Load Ride-Through Settings

For this filing, DG-PV is modeled as three inverter-based generators connected to each load bus on the system. The three generators represent 1) legacy PV, 2) reprogrammed legacy PV, and 3) full ride-through DG-PV. Modeling the characteristics of different vintages of DG-PV allows the dynamics and protection settings of each DG-PV type to be modeled in greater detail. Table O-3 below shows the ride-through settings for the different DG-PV models. A custom user-written generator protection model was developed to consolidate all protection settings into one model per machine.

Type		Legacy Range	Legacy Trip (sec)	Reprogrammed Range	Reprogrammed Trip (sec)	Full Range	Full Trip (sec)
Frequency		-	-	-	-	$f > 64$	0.1667
		-	-	-	-	$f > 63$	20
		$f > 60.5$	0.157	$f > 60.5$	0.157	-	-
		$f < 59.3$	0.157	-	-	-	-
		-	-	$f < 57$	0.157	$f < 57$	20
		-	-	-	-	$f < 56$	0.1667
Voltage		V > 1.2	0.157	V > 1.2	0.157	V > 1.2	0.1667
		V > 1.1	0.99	V > 1.1	0.99	V > 1.1	0.92
		V < 0.88	1.99	V < 0.88	1.99	V < 0.88	20
		-	-	-	-	V < 0.7	10
		V < 0.5	0.157	V < 0.5	0.157	V < 0.5	0.5

Table O-3. Inverter-based Generator Ride-Through Settings

As recommended by Siemens consultants, the GE PV (GEPVG) custom user-written model is being used to model the dynamic response of all DG-PV generators.

Grid-Scale Wind and PV Models

For existing grid-scale wind and PV generators, user-written models provided by developers are used with contract ride-through settings. Future grid-scale wind and PV generators are modeled with the generic renewable energy generator/converter model (REGCAU1) and generic electrical control models for wind and large-scale PV (REECAU1/REECBU1). Ride-through settings for future grid-scale wind and PV generators use the full ride-through settings in Table O-3 above.

Modeling Assumptions

The following assumptions are common across cases:

- The kinetic energy for each generator was calculated by multiplying the unit H-constant by the unit MVA rating. This does not take into account the inertia contribution from the unit's auxiliary loads. For the system, the total kinetic energy is the sum of all unit kinetic energies. This does not take into account the inertia contribution from system load.
- Loads are modeled to have frequency dependence. A load frequency characteristic exponent of 2 translates to a 2% decline in real power consumption for a 1% drop in frequency. For example, in a 1000 MW system, load will decrease by 20 MW for a system frequency of 59.4 Hz, a decrease of 0.6 Hz. This relationship is attributed to the makeup of the system load, with a portion of it consisting of motor loads. The frequency response from motor loads is typically one to two percent of load.

- Legacy PV inverters have a frequency range of 59.3 Hz to 60.5 Hz. The table below shows the assumptions made as to the amount of inverters that still have these frequency ranges. These figures were estimated by the Companies based on a review of the inventory of installed inverters and what ride-through standards applied to these inverters. If a contingency drives system frequency outside of this range, inverters are required to disconnect from the system within 0.16 seconds (for simplicity, legacy PV is modeled to immediately trigger disconnect with inverter time delays). The capacity of legacy PV that would disconnect at 60.5 Hz is higher than the capacity that at 59.3 Hz, as shown in Table O-4 below. In the simulations, the amount of PV generation lost is less than the nameplate capacity to the extent that PV capacity factors are below 100% for the simulated hour. All other DG-PV will continue generating if frequency remains between 56 Hz to 64 Hz and voltage remains above 0.5pu.

Legacy PV Capacities					
Island	**O'ahu**	**Hawai'i**	**Maui**	**Moloka'i**	**Lana'i**
Size PV Systems (kW) @ 59.3 Hz	73,499	7,940	7,205	1,100	96
Size PV Systems (kW) @ 60.5 Hz	215,878	56,600	76,656	1,100	464

Table O-4. Legacy PV Capacities

The focus of the frequency response analyses are on the system's first-swing stability. Although simulations can run for 10-20 seconds, we do not simulate automatic generation control (AGC) interaction following a contingency event. If system frequency exceeds a given deadband, e.g. 59.5 Hz, AGC will dispatch all generators within it control cycle of 2-seconds. Therefore, under frequency load shed kicker blocks that are designed to activate in 10 seconds were disabled.

To simulate the performance of autonomous-controlled inverter-based systems, DER resources are modeled with droop response to simulate frequency-watt functionality. Droop response is inversely proportional to the system's frequency response profile so this resource would be characterized as PFR.

Fast frequency response one (FFR1) was modeled as a step change to full output within 12-cycles to simulate Auto-scheduling control of a battery energy storage system (BESS). In Auto-scheduling control, the BESS will receive a command to dispatch to full output on an open-breaker signal from AES or Kahe 5/6.

Fast frequency response two (FFR2) was modeled as a load shed block that is triggered at 59.7 Hz to simulate Demand Response load control technology in the near future. For both FFR1 and FFR2, we assumed these capacities are available until supplemental reserves can restore system frequency to 60 Hz. Otherwise, loss of this capacity could trigger a secondary contingency event.

Limitations of Modeling Simulations

As with any modeling simulation, the dynamic performance of transmission system components, especially generating resources, cannot be accurately captured in a model. Dynamic models are a critical component of these analyses. Governor and exciter models with default settings are adequate for simulating system contingency events when many units are running. As traditional synchronous generation is displaced, more sophisticated and accurate, dynamic models will be required to ensure confidence in simulation results. Complex dynamic load models will also be required to better understand load impacts on voltage stability.

Production cost simulation models optimize system performance with perfect foresight and cannot take into account operational changes to mitigate system risks. For example, system operators may commit non-economic units to mitigate system risks when transmission lines are taken out of service for maintenance.

Screening Tool Improvements

For the April filing, a single-bus network model was developed in PSS/E that allows us to perform dynamic loss of generation simulations for every hour in selected years, using the production cost simulation output to determine the dispatch. For each hour, the screening tool calculated the frequency nadir for a generation trip of the largest online resource. Based on the results of the screening tool, two informative hours (boundary hour and typical hour) are selected for further detailed analysis. The comprehensive analysis uses the full network PSS/E model to determine the frequency response reserve requirements to meet TPL-001.

Subsequent to the analysis performed for the April PSIP filing, the following improvements were made to the screening tool:

- Calculates FFR1 requirement for each hour in the study year
- Ability to use a FFR2 hourly profile as an input
- Incorporates future resources such as GE 151MW combined cycle, pumped storage hydro, and load shifting storage
- Improvements to the UFLS implementation
- Calculates total MVA of online synchronous generation, to check if resources meet fault current requirements
- Adjustments to the methodology on determining if a generating unit is on or off
- Ability to accept Plexos hourly output data as input to the tool

In additions to the above improvements to the screening tool after the April filing, the methodology in selecting the “boundary” and “typical” hours was slightly modified. For the April filing, the "boundary hour" was the hour with the lowest frequency nadir. With the improvement in the screening tool to calculate FFR1 requirement, the "boundary hour" was selected based on highest FFR1 requirement from the group of hours with the severest UFLS block tripped. This would represent a very high impact contingency but with a lower probability of occurrence. The "typical hour" represents an impact that may not be as significant but the probability of occurrence is higher. For O'ahu, the "typical hour" was selected based on the largest weekday hour FFR1 requirement from a severe frequency range with about 800-1000 hours occurrence. For Hawai'i and Maui, the "typical hour" was selected based on the largest FFR1 requirement from a weekday daytime hour with less blocks shed than the "boundary hour". If screening analysis did not produce sufficient hours, only a boundary hour was selected and analyzed.

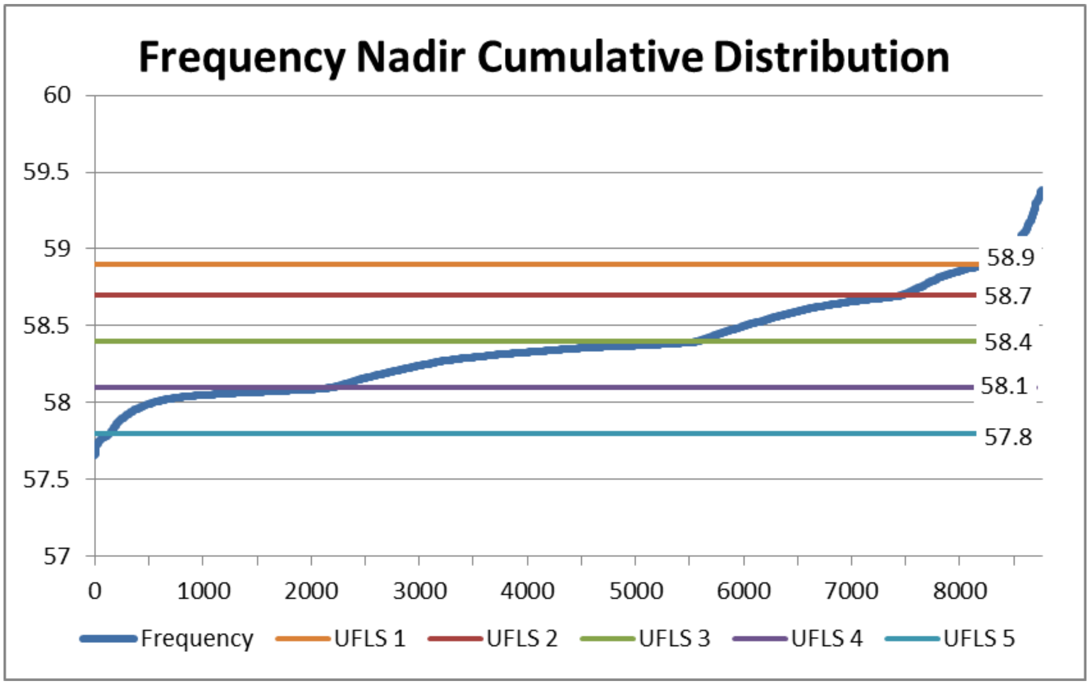

Figure O-5. Frequency Nadir Duration Curve

Figure O-5 shows the duration curve of the frequency nadirs for all the hours in 2023. The horizontal lines show the UFLS blocks for O'ahu. The example chart above shows the system's exposure to tripping one block of UFLS is approximately 8,000 hours of the year. Furthermore, the system is at risk of requiring four blocks of UFLS (58.1 Hz) for 2000 hours of the year.

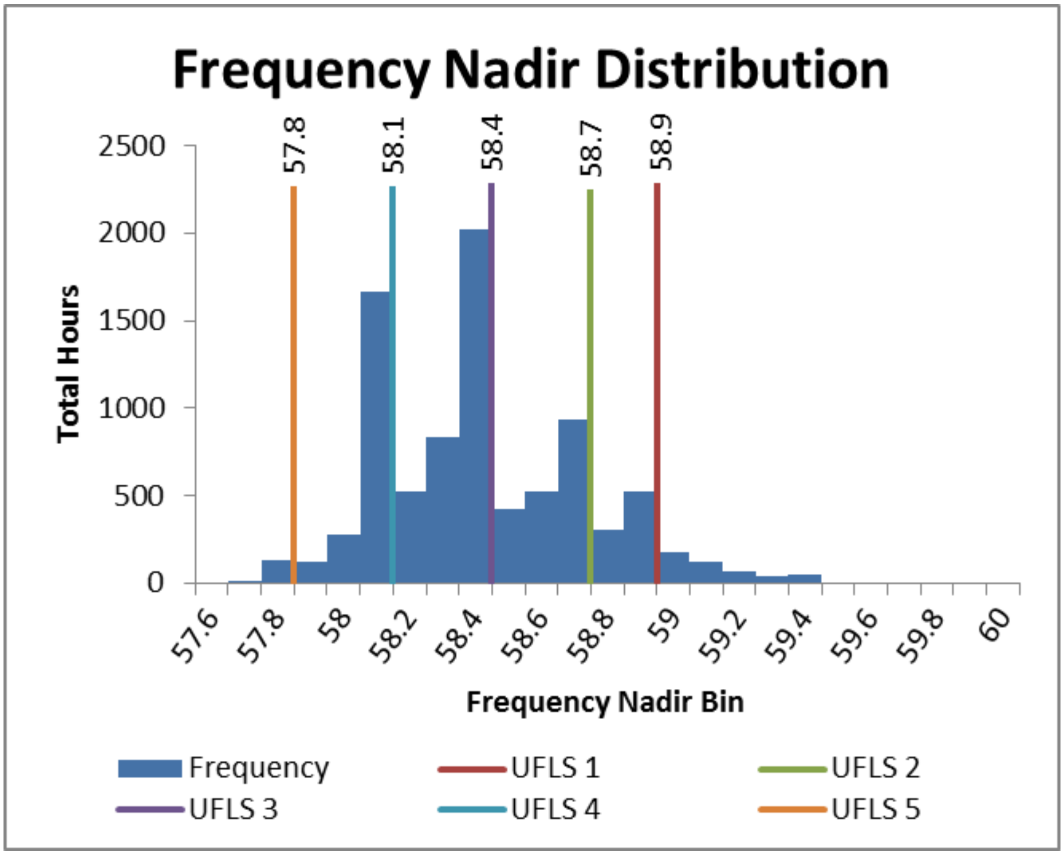

Figure O-6. Frequency Nadir Histogram

Figure O-6 shows the hourly distribution of the frequency nadirs as a result of loss of generation contingency events for 2023. The same source data for the chart above was used to generate this chart, which grouped the nadir data in 0.1Hz frequency buckets.

Using the frequency nadir distribution chart, two hours are selected for further analysis using the full PSS/E system model. The first hour is chosen by selecting a severe nadir from a large frequency grouping that can occur more frequently in the year (large bar on graph, with significant blocks load shed).

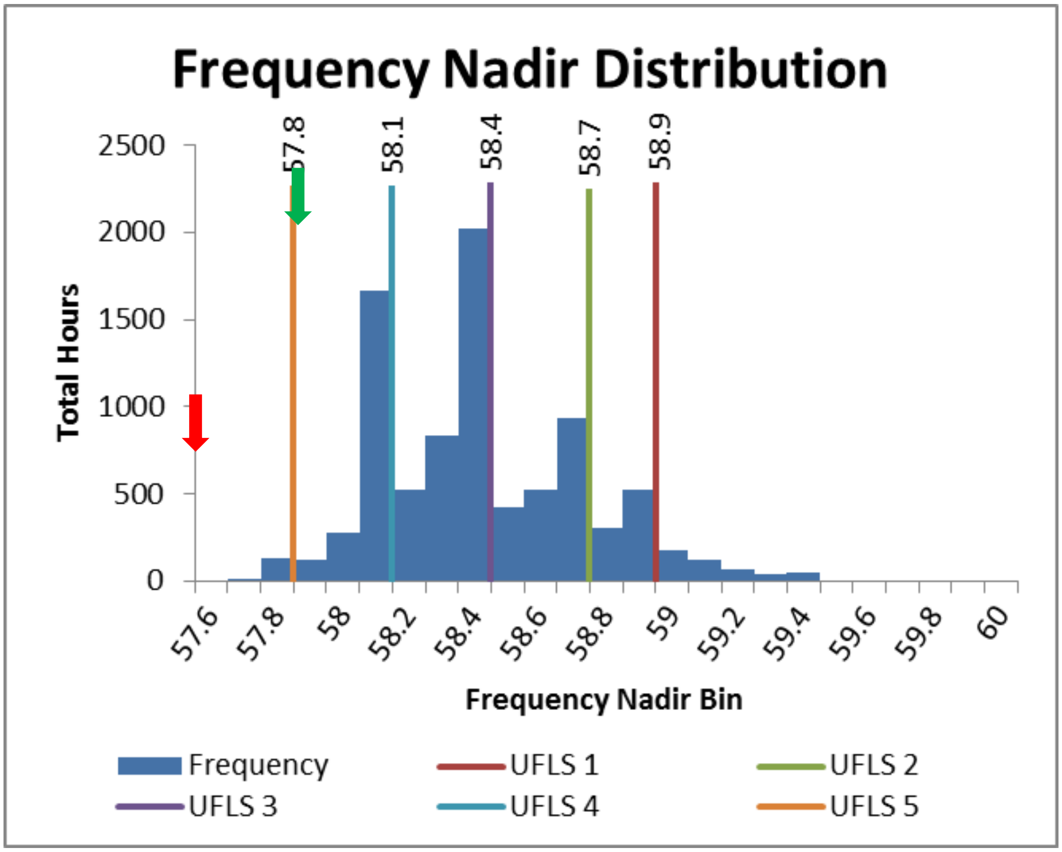

Figure O-7. Frequency Nadir Histogram – Selection

Figure O-7 illustrates the selection of hours for more detailed analysis. The green arrow represents a typical hour for a range of frequency nadirs from 58.0 - 58.1 Hz that could occur 1636 hours in 2023. The red arrow represents a boundary hour for a range of frequency nadirs from 57.6 - 57.8 Hz that could occur 129 hours in 2023. The selected hours are further analyzed using the comprehensive PSS/E database.

O'AHU SYSTEM SECURITY ANALYSIS

State of the System

The O'ahu system does not meet the requirements of TPL-001. The proliferation of DG-PV poses the biggest challenge to system security because it imposes fundamentally conflicting requirements on the electrical system; 1) the reduction of system load displaces synchronous generators and 2) DG-PV increases regulating and contingency reserve requirements that are traditionally provided by synchronous generators.

More specifically, transformation of the electrical system must address the following system security issues:

- DG-PV displaces synchronous generators that provide essential grid services like inertia, regulating reserves, and system fault current
- DG-PV reduces the capacity of the system's under frequency load shed scheme (UFLS)
- Legacy DG-PV increases the magnitude of a loss of generation contingency
- DG-PV is currently an uncontrollable and invisible resource

The design of an electrical system is based on the inherent characteristics of synchronous generators. A synchronous generator is basically a large rotating magnet that provides essential grid services like inertia and fault current to the system; two critical parameters required to maintain system stability. As synchronous generators are cycled offline to make room for as-available resources, the stability margin of the system is reduced and we begin to approach the stability limits of the system.

Besides the loss of these stability parameters, lower daytime loads increases the magnitude of the generation contingency. Prior to the proliferation of DG-PV, an AES trip at full output typically represented 15 – 18% of the system generation. Today, an AES trip combined with loss of generation from legacy PV can represent 30% - 35% of the typical daytime load, doubling the magnitude of the contingency event.

Lower system inertia and the larger magnitude contingency increases the rate of change of frequency (RoCoF), reducing the time for traditional governor droop and demand response to arrest the decay in system frequency. Analysis of recent AES trip events confirms that O'ahu's electrical system is operating with a smaller stability margin and is relying on multiple blocks of UFLS to help stabilize system frequency.

The UFLS scheme is designed to stabilize system frequency for severe loss of generation contingency events and is a last-resort system preservation scheme to prevent an island-wide blackout. Under frequency load shed schemes are implemented in blocks of load that are coordinated to shed increasing amounts of load at various frequency settings, progressively increasing the amount of load shed for larger contingency events. The intent is to preserve the system for the low probability/high impact contingency events or unforeseen cascading events.

The initial blocks of UFLS target residential load and avoids critical loads like hospitals, emergency responders, department of defense facilities, schools, commercial sectors, etc. Unfortunately, the proliferation of DG-PV is primarily on these residential distribution circuits so the daytime UFLS capacities for Blocks 1-3 continue to degrade; making it difficult to maintain adequate load capacities and coordination.

Minimum Fault Current Analysis

O'ahu is the only system that has established a minimum fault current requirement based on analysis. Simulations were performed for three phase-to-ground, two phase-to-ground, single phase-to-ground, and line-to-line faults for different unit commitment schedules while monitoring 46kV bus currents. Units were cycled offline until one or more of the Minimum Acceptable Fault Current Limits from Table O-5 were violated.

46kV Circuit		3LG Fault	2LG Fault	1LG Fault	LL Fault
Circuit Name	*Circuit Breaker*	*Fault Current (Amps)*	*Fault Current* (Amps)*	*Fault Current (Amps)*	*Fault Current (Amps)*
Halawa 1	4865	2834	2665	2242	2451
Halawa 2	4864	2704	2492	2068	2338
Halawa 3	4863	2596	2370	1901	2245
Halawa 4	4883	2894	2677	2247	2503
School - Puunui	4582	8366	8062	7154	7217
School - Nuuanu	4409	7034	6570	5565	6071
Iwilei 1	4401	5476	4966	3751	4730
Iwilei 2	4402	6375	5805	4577	5504
Koolau - Kahuku	4464	1002	925	600	868
Koolau - Wailupe 1	4467	1832	1659	1186	1587
Koolau - Wailupe 2	4477	1926	1737	1245	1668
Koolau - Aikahi	4465	2599	2368	2014	2251
Koolau - Kaneohe	4466	2220	2022	1561	1922
Koolau - Nuuanu - Laelae	4484	2633	2436	2056	2280
Koolau - Pohakupu	4469	2095	1894	1409	1814
Koolau - Kailua	4414	2027	1842	1385	1755
Pukele 1	4813	3115	2945	2649	2695
Pukele 3	4815	2732	2527	2119	2364
Pukele 5	4820	2497	2285	1823	2160
Pukele 6	4817	2373	2164	1696	2054
Pukele 7	4818	2806	2592	2176	2428
Pukele 8	4819	3040	2844	2475	2630
Makalapa 42	5133	4816	4425	3516	4164
Makalapa 46	5128	5730	5549	4860	4952
Wahiawa - Waialua 2	4683	921	352	512	797
Wahiawa - Milikua	4621	1433	683	927	1240
Wahiawa - Mililani	4448	2814	1931	2289	2434
Wahiawa - Waimano	4449	2048	1082	1417	1772
Kahe - Mikilua	4714	1708	1042	1293	1478
Kahe - Standard Oil 1	4717	2541	1978	2489	2182
Kahe- Standard Oil 2	4715	1693	1025	1276	1465
Kahe - Permanente	4716	2205	949	1290	1855
CEIP 42	5156	3224	3003	2618	2788
CEIP 45	5159	3264	3051	3473	2798
CEIP 46	5160	2441	2160	1461	2046
Ewa Nui 41	5338	2646	2427	1951	2288
Ewa Nui 42	5339	2843	2660	2247	2459
Waiau - Steel Mill	4653	2655	2412	1659	2297
Waiau - Barbers Point	4486	3994	3627	2793	3452
Waiau - Mililani	4453	1748	1655	1122	1513
*Highest Phase Current					

Table O-5. Fault Current Requirements

Table O-5 lists the minimum fault current requirements for each 46 kV bus. To meet the minimum fault current requirements, 515 MVA of synchronous units must be online on the 138 kV system. Any combination of synchronous generating units or synchronous condensers will suffice. Synchronous machines at the 46kV sub-transmission level must be analyzed because of the impedance of the 138-46kV transformers.

Resource plans are screened to determine if the unit commitment schedule violates the 515 MVA requirement. If the violation occurs for less than 200 hours per year, units can be committed in VPO to meet the fault current requirement. Otherwise, synchronous condensers are required to maintain system security without significantly impacting system operating cost or renewable energy curtailment.

Historical Contingency Events

O'ahu has experienced several AES trip events over the past two years that required multiple blocks of UFLS to stabilize system frequency. On June 9, 2014, AES experienced a turbine trip at full output that resulted in an effective loss of 198 MW. With the additional loss of 50 MW of generation from Legacy PV, the contingency event was 248 MW that represents a 30% loss of generation. The system was carrying 310 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in less than 3 seconds. Three blocks of UFLS (approximately 110 MW) were required to stabilize system frequency.

On July 22, 2015, AES experienced a turbine trip at full output that resulted in an effective loss of 201 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 256 MW that represents a 29% loss of generation. The system was carrying 283 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.4 Hz in 3.25 seconds. Three blocks of UFLS (approximately 82 MW) were required to stabilize system frequency.

On July 23, 2015, AES experienced a breaker trip at full output that resulted in an effective loss of 180 MW. With the additional loss of 55 MW of generation from Legacy PV, the contingency event was 235 MW that represents a 28% loss of generation. The system was carrying 297 MW of contingency reserves at the time of the AES trip, exceeding the capacity of the contingency event. Lower system inertia and the magnitude of the contingency event drove the frequency nadir to 58.5 Hz in less than 3 seconds. Three blocks of UFLS (approximately 82 MW) were required to stabilize system frequency.

Figure O-8 shows the frequency response profiles of these events.

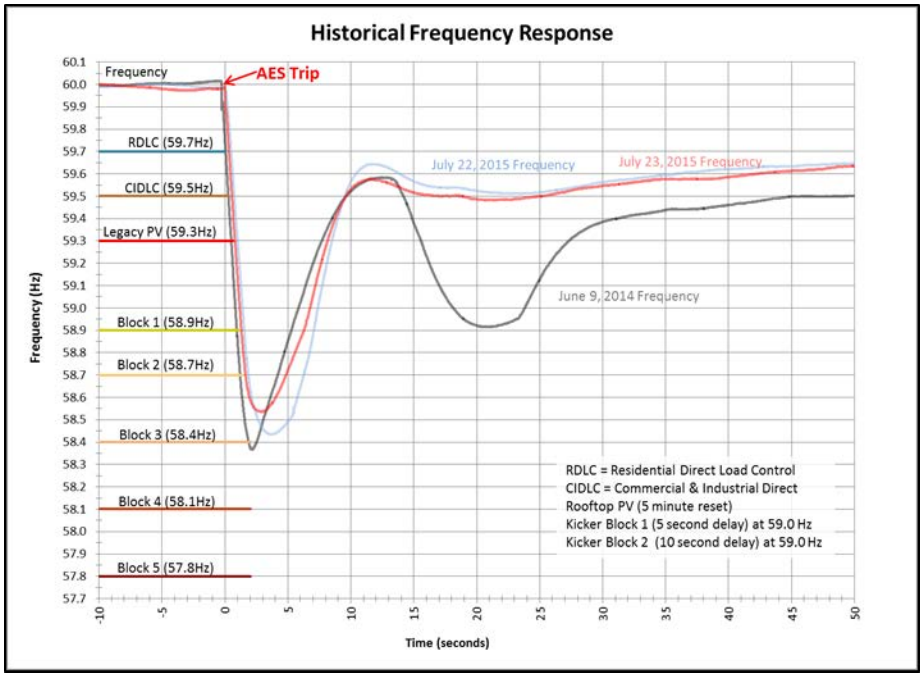

Figure O-8. Frequency Response Profile of Historic Contingency Events

Table O-6 shows the system characteristics of the historical system events.

	June 9, 2014 Event 9:49 AM	July 22, 2015 Event 11:23 AM	July 23, 2015 Event 11:22 AM
System Load	880 MW	920 MW	890 MW
Generator Units On-Line	K1, K2, K3, K4, K5, K6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP	K1, K2, K3, K4, K6, W4, W6, W7, W8, AES, H-POWER, KPLP
Total Kinetic Energy	6233	6059	6059
Synchronous Inertia Response	211	169	197
AES Gross MW Loss of Generation	198 MW	198 MW	180 MW
Excess Spinning Reserve	130 MW	103 MW	117 MW
Excess Quick Load Pick Up	50 MW	72 MW	78 MW
Estimated PV Tripped at 59.3Hz	50 MW	56 MW	55 MW
Frequency Nadir	58.4 Hz	58.4 Hz	58.5 Hz
Rate of Change of Frequency*	-0.94	-0.75	-0.84
Number of UFLS Blocks Shed	Blocks 1-3 (96 MW) & Block 5 (13.5 MW)**	Kicker Block 1 (20 MW) & Blocks 1-2 (62 MW)	Kicker Block 1 (20 MW) & Blocks 1-2 (65 MW)
*Note: Circuit in Block 5 tripped causing additional load shed			

Table O-6. Historical Contingency Events

2017

Loss of Generation Simulation

System security analysis was performed on two hours that were selected from the Theme 5 (a no-LNG case with generation modernization) production simulation data that represents a typical hour and a boundary condition.

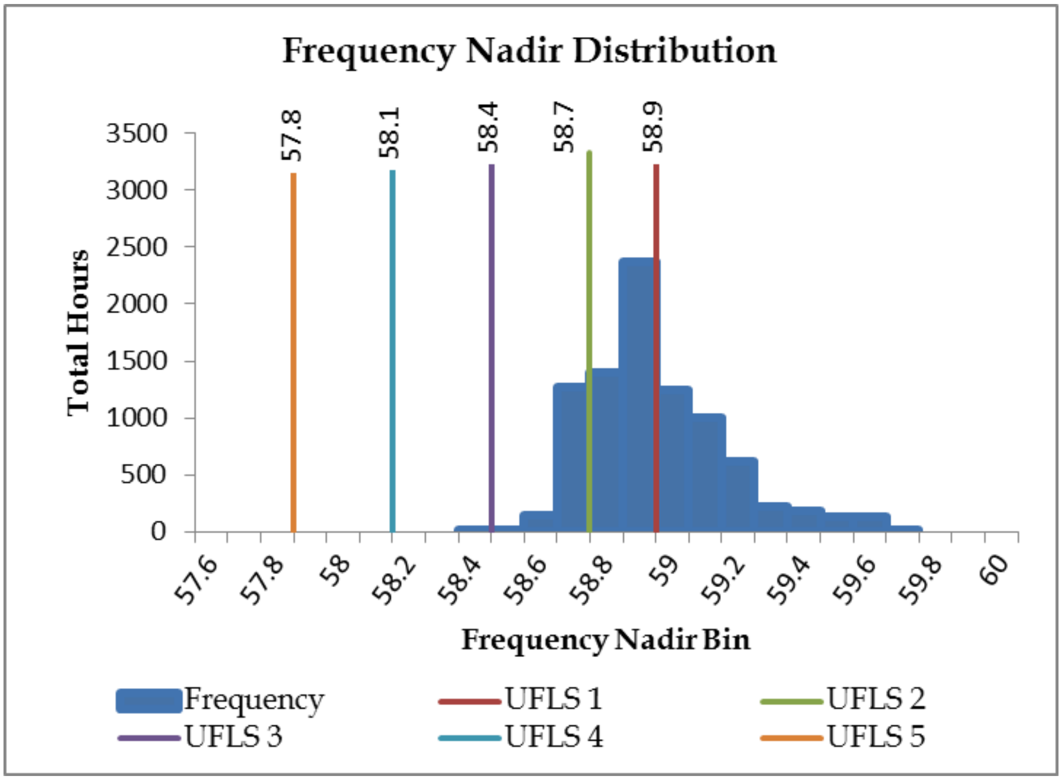

Figure O-9. Frequency Nadir Histogram 2017

Figure O-9 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year in 2017. The typical hour selected from the maximum distribution of 1275 hours was 1:00 PM on Friday, November 24. The frequency nadir range for the typical hour is 58.6 – 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 9 hours was 4:00 AM on Sunday, March 26. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

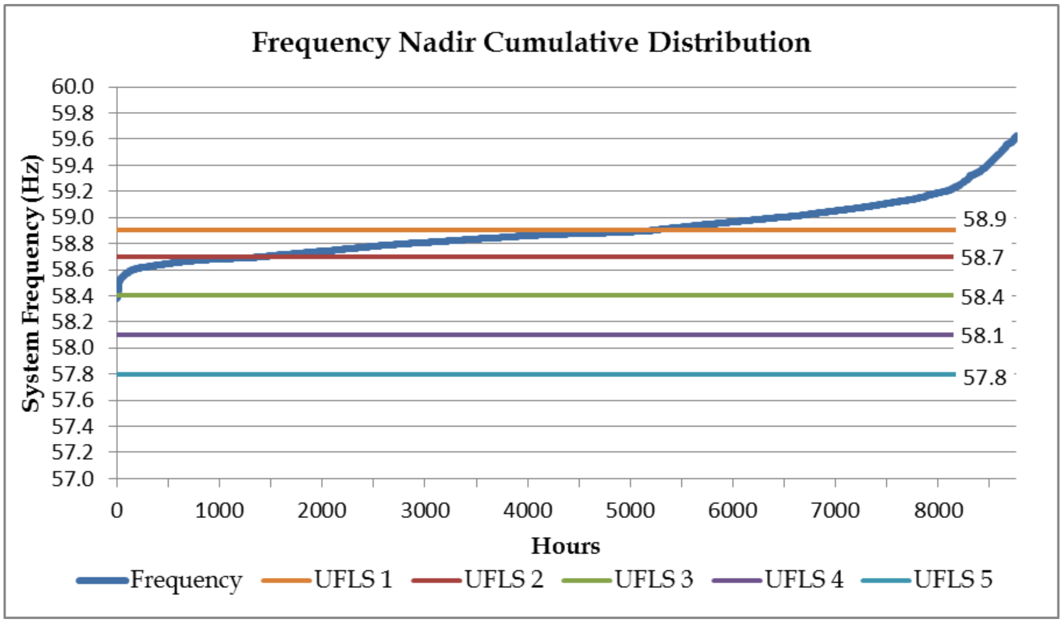

Figure O-10. Frequency Nadir Distribution Curve 2017

Figure O-10 shows the frequency nadir duration curve for the Theme 5 resource plan in 2017. The system is at risk of UFLS for 5203 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Fri 11/24/17 Hour 13			Theme 5 - AES Trip Boundary Sun 3/26/17 Hour 4		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	16.0	6.5	6.0			
AES	189.0	63.0			2.57	239.0	615	180.0	9.0	117.0	180.0	9.0	117.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	60.0	24.0	31.0	74.0	10.0	45.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	21.0	19.0	11.0	16.0	24.0	6.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	60.0	24.0	31.0			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	5.0	VPO	VPO	26.0	56.2	2.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426				26.0	56.2	2.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	6.0	VPO	VPO	37.0	49.2	13.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	6.0	VPO	VPO	26.0	59.3	2.4
Kahe 5	134.6	21.0			4.36	158.8	692	21.0	113.6	0.0	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692	40.0	93.8	0.0			
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261	23.5	31.0	0.0			
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	6.0	VPO	VPO	24.0	59.3	0.2
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	6.0	VPO	VPO			
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124						
Honolulu 9	0.0	0.0			1.95	64.0	125						
Total Wind	99	0						21			5		
-Kahuku	30	0						5			0		
-Kawailoa	69	0						16			5		
-Na Pua Makani													
-CBRE Wind													
DG-PV	590	0						350			0		
Station PV	39	0						24			0		
Total Kinetic Energy									6074			4386	
Total Load									892			584	
Total Thermal Generation									497			579	
Total Renewable Generation									395			5	
Total Generation									892			584	
Excess Generation									0			0	
Total Up Regulation									321			334	
Total Down Regulation									217			312	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		43.6	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		128.1	60.5Hz Output		0.0

Table O-7. Unit Commitment and Dispatch 2017

Table O-7 shows the unit commitment and dispatch schedules for the typical hour (11/24/17, 1:00 PM) and boundary hour (3/26/17, 4:00 AM).

Simulations were performed to determine system performance for the largest loss of generation contingency for the typical and boundary hours. For O'ahu, this is an AES turbine trip at full output and the subsequent loss of generation from legacy PV.

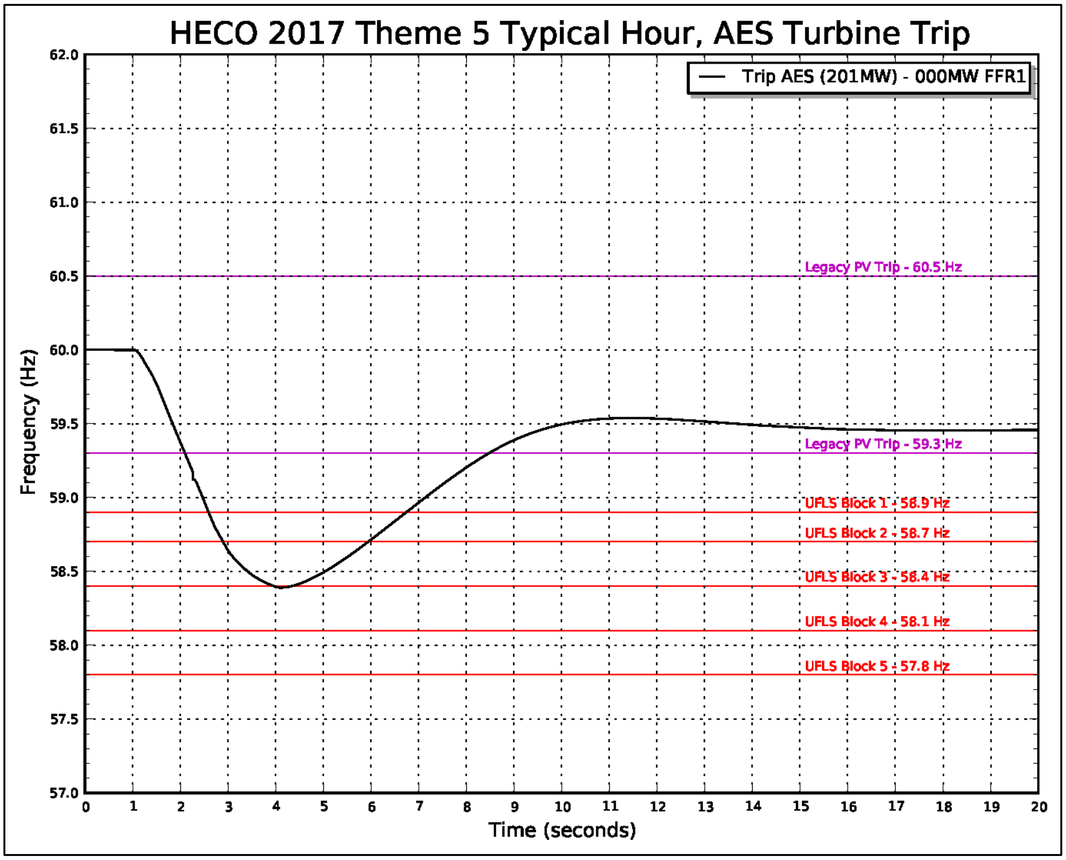

Figure O-11. Frequency Response Profile Typical Hour

Figure O-11 shows the frequency response profile for an AES trip for a typical hour. System kinetic energy is 6074 MW-sec and the capacity of legacy PV that will disconnect from the system is 43.6 MW. The frequency nadir breached 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

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Maui Electric
Hawai'i Electric Light

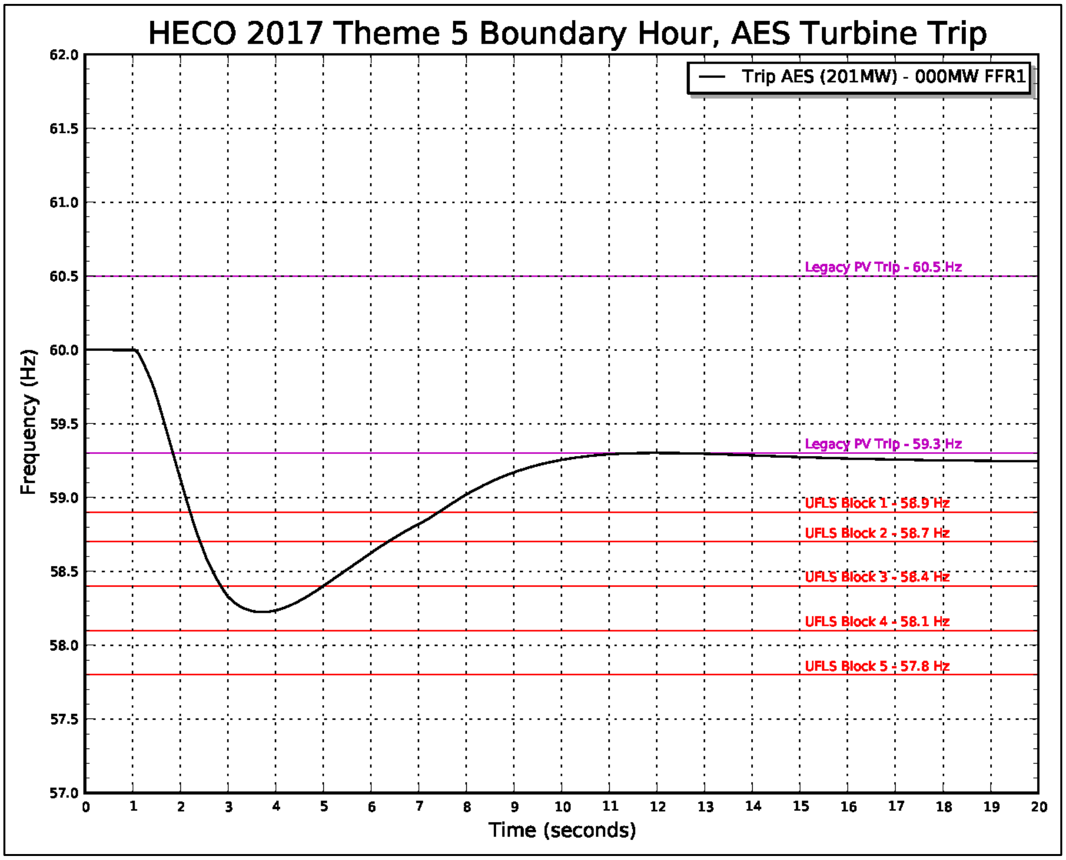

Figure O-12. Frequency Response Profile Boundary Hour

Figure O-12 shows the frequency response profile for the boundary hour. System kinetic energy is 4386 MW-sec. The frequency nadir breached 58.3 Hz that requires three blocks of UFLS to stabilize system frequency.

138 kV Fault Simulation

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

In addition, the aggregate loss of inverter-based generation could drive the system frequency nadir below critical operating thresholds. The under frequency trips settings for thermal units typically activate at 57.0 Hz with various time delay setting depending on turbine manufacturer recommendations. At 56.0 Hz, synchronous generators will trip and inverter-based generation will disconnect from the system.

For the fault analysis, a three-phase fault was placed on transmission elements to evaluate system performance for normally cleared and delayed clearing faults. Normally cleared faults are isolated in 5-cycles with breaker reclosing activated after a 30-cycle time delay. Delayed clearing faults are isolated in 18-cycles to simulate a breaker that fails to open. A breaker failure initiates the backup protection scheme that opens adjacent circuit breakers to clear the fault, isolating an additional 138 kV circuit.

Table O-8 shows the unit commitment and dispatch for the fault analysis.

Unit	Unit Ratings							Theme 5 - Fault Sun 7/23/17 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.1	12.4	0.1
AES	189.0	63.0			2.57	239.0	615	117.9	71.1	54.9
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	46.7	37.3	17.7
Kalaeloa ST	40.0	10.0			4.70	61.1	287	22.2	17.8	12.2
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	46.7	37.3	17.7
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	5.0	VPO	VPO
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	5.7	VPO	VPO
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	7.4	VPO	VPO
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	5.4	VPO	VPO
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692	40.0	93.8	0.0
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256	23.8	29.9	0.0
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	8.0	VPO	VPO
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	6.0	VPO	VPO
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447	5.9	44.0	0.0
CIP1	112.2	41.2			4.72	162.0	765			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	109	0						21		
-Kahuku	30	0						6		
-Kawailoa	69	0						15		
-Na Pua Makani	24	0						0		
-CBRE Wind	10	0						0		
DG-PV	590	0						472		
Station PV	78	0						34		
Total Kinetic Energy									6251	
Total Load									924	
Total Thermal Generation									397	
Total Renewable Generation									527	
Total Generation									924	
Excess Generation									0	
Total Up Regulation									344	
Total Down Regulation									124	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		58.8
	60.5Hz Capacity			215.9				60.5Hz Output		172.7

Table O-8. Unit Commitment and Dispatch Fault Analysis

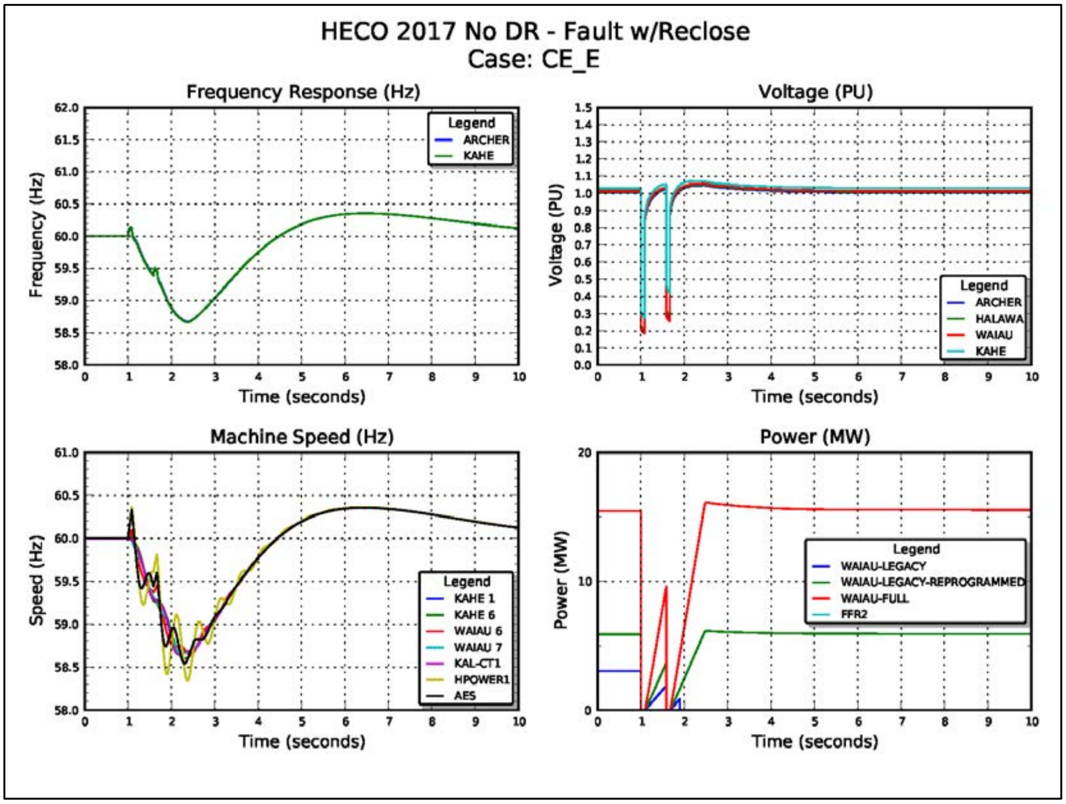

Figure O-13. System Performance for Normally Cleared Fault

Figure O-13 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 472 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from DG-PV is restored but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and two blocks of UFLS are able to stabilize system frequency at 58.7 Hz. The system remains stable for all normally cleared faults.

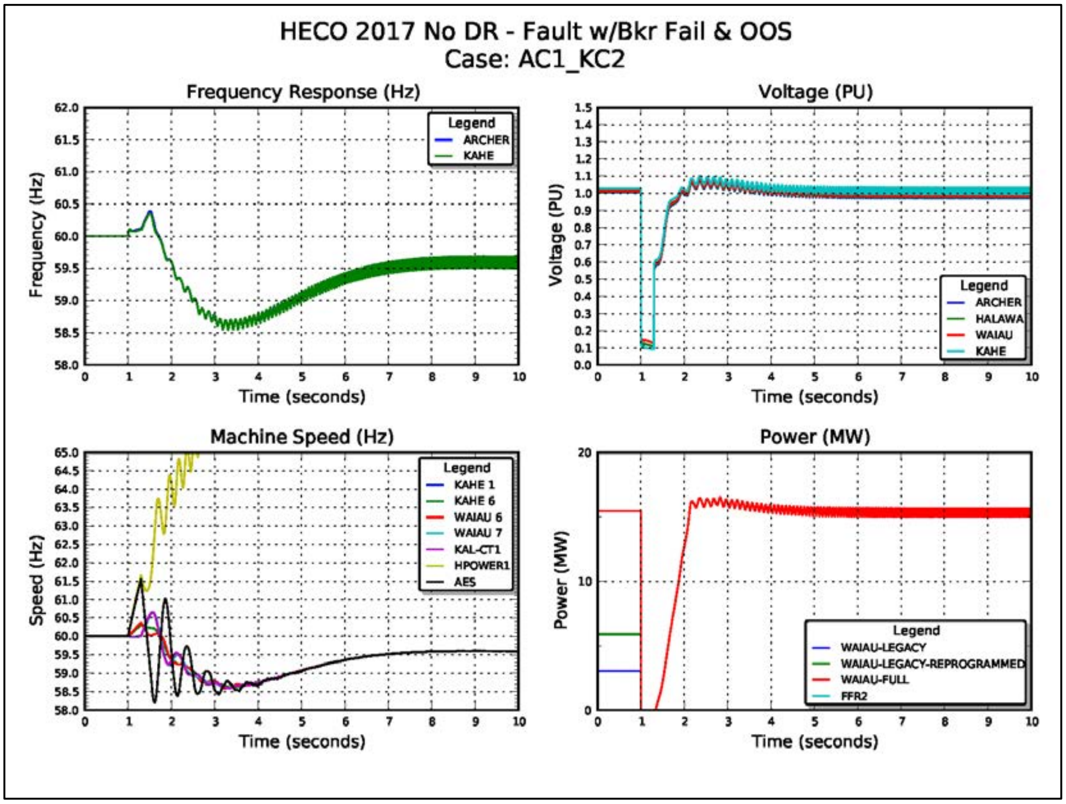

Figure O-14. System Performance for Delay Cleared Fault

Figure O-18 shows the system performance for a delay cleared fault on the AES-CEIP 1 circuit and BKR 323 fails to operate. A breaker failure initiates the backup protection scheme to clear the fault, isolating the Kahe-CEIP2 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through setting for longer than 0.5 seconds, causing 472 MW of inverter-based generation to trip offline. HPOWER 1 loses synchronism almost immediately after the fault, indicating the delayed clearing exceeded its critical clearing time for stability. Further analysis is required to determine if HPOWER 1 requires out-of-step protection.

2017 138 kV Fault Analysis					
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Fault Hour Condition
AES-CEIP 1	AES	320	15	AES-HP	Stable
AES-HP	AES	320	15	AES-CEIP 1	Stable
AES-CEIP 2	AES	323	15	AES Gen	Unstable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable

Table O-9. Summary of Results Breaker Fail Analysis

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Hawai'i Electric Light

Table O-9 is the summary of results for the breaker failure analysis. Seven simulations resulted in system instability where HPOWER 1 lost synchronism and/or system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to trip.

Post April No DR Plan - Theme 5

System security analysis performed on the Theme 5 resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

System security analysis was performed on the Theme 5 resource plan to bring the system into compliance with TPL-001.

QV Analysis

The O‘ahu transmission system is designed to operate with two transmission lines out of service (N-2) while maintaining a minimum bus voltage of 0.92 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum 515 MVA requirement. Therefore, only synchronous condensers are evaluated in these analyses.

For O‘ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko‘olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							Theme 5 - QV Dispatch Mon 8/5/19 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	18.0	4.5	8.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	34.0	6.0	24.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	27.0	59.2	3.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692	29.9	104.7	8.9
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124		Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125		Synch. Cond.	
Total Wind	133.0	0.0						70.0		
-Kahuku	30.0	0.0						17.0		
-Kawailoa	69.0	0.0						27.0		
-Na Pua Makani	24.0	0.0						21.0		
-CBRE Wind	10.0	0.0						5.0		
-Future Wind	0.0	0.0								
-Offshore Wind	0.0	0.0								
Total Station PV	182.2	0.0						165.0		
-KS2	5.0	0.0						5.0		
-KREP	5.0	0.0						4.0		
-Waianae	27.6	0.0						27.6		
-Kawailoa PV	49.0	0.0						33.8		
-Mililani 2	14.7	0.0						14.7		
-Waiawa	45.9	0.0						45.9		
-Westloch	20.0	0.0						20.0		
-CBRE PV	15.0	0.0						14.0		
DG-PV	701.0	0.0						469.0		
Total Kinetic Energy									4269	
Total Load									1262	
Total Thermal Generation									558	
Total Renewable Generation									704	
Total Generation									1262	
Excess Generation									0	
Total Up Regulation									296	
Total Down Regulation									300	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		49.2
	60.5Hz Capacity			215.9				60.5Hz Output		144.4

Table O-10. Unit Commitment and Dispatch 2019 QV Analysis

Table O-10 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 5 - QV MVAR Capability Mon 8/5/19 Hour 13		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.8	33.2	-2.8
HPOWER-2	28.0	-16.0	2.8	25.2	-18.8
AES	99.4	-49.8	34.1	65.3	-83.9
Kalaeloa CT-1	84.5	-35.9	17.9	66.6	-53.8
Kalaeloa ST	84.5	-35.8	17.9	66.6	-53.7
Kalaeloa CT-2	42.1	-16.7	17.9	24.2	-34.6
Kahe 1	71.0	-52.0			
Kahe 2	68.3	-51.6	43.7	24.7	-95.2
Kahe 3	73.7	-24.3	43.7	30.0	-68.0
Kahe 4	67.7	-24.1	43.7	24.0	-67.7
Kahe 5	117.8	-71.3	100.9	16.9	-172.2
Kahe 6	111.8	-64.2			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	87.4	-110.9	19.3	68.1	-130.2
-Kahuku	17.9	-17.9	6.6	11.2	-24.5
-Kawailoa	50.0	-74.5	9.0	41.0	-83.5
-Na Pua Makani	16.4	-15.4	3.6	12.8	-19.0
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	0.0	0.0			
-Offshore Wind	0.0	0.0			
Total Station PV	109.4	-109.4	14.2	95.2	-123.6
-KS2	1.6	-1.6	1.6	0.0	-3.3
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	3.2	11.3	-17.7
-Kawailoa PV	36.8	-36.8	-0.4	37.2	-36.3
-Mililani 2	10.7	-10.7	0.4	10.3	-11.1
-Waiawa	32.9	-32.9	3.8	29.1	-36.7
-Westloch	6.3	-6.3	3.5	2.8	-9.7
-CBRE PV	4.7	-4.7	0.1	4.6	-4.8
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			325.3		
Total Renewable MVAR Generation			33.4		
Total Cap Bank MVAR			183.5		
Charging MVAR			76.4		
Total MVAR Supply			618.5		
Total MVAR Load			411.0		
Total MVAR Losses			207.6		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				540.0	
Total MVAR Absorb Capability					-904.6

Table O-11. MVAR Capability 2019 QV Analysis

Table O-11 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School

Table O-12. N-2 Contingencies 2019 QV Analysis

Table O-12 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

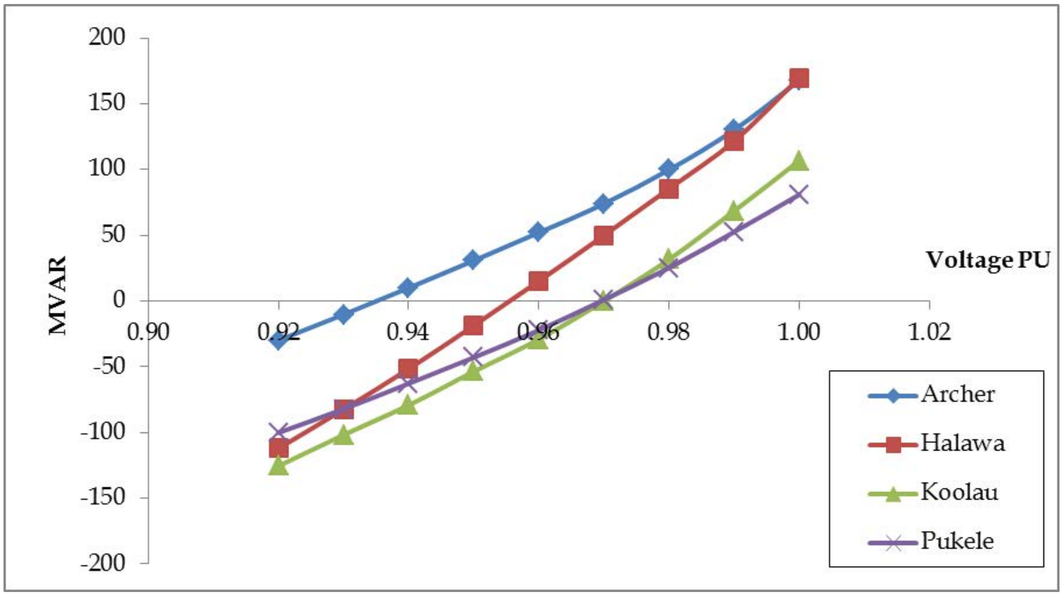

Figure O-15. QV Curves 2019

Figure O-15 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation requires an additional 31 MVAR to maintain system voltage at 0.95 PU for an N-2 contingency. The system has 540 MVAR of reactive power reserve capacity but all of these resources are on the west side of the island, far from the load center.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	168	154	130	154	100	135	74	135	52	135	31	135	10	135	-10	135	-30
120	Halawa	125	170	154	122	154	86	154	50	154	15	154	-19	154	-52	154	-82	154	-112
150	Koolau	154	107	154	69	154	32	125	0	125	-29	125	-54	125	-79	125	-102	125	-125
170	Pukele	154	81	154	53	125	25	125	1	125	-22	125	-43	125	-63	125	-82	125	-100

Table O-13. Summary of Results 2019 QV Analysis

Table O-13 shows the summary of results for the 2019 QV analysis. The Archer bus requires 31 MVAR to maintain 0.95 PU voltage for outages of the Halawa-Iwilei and Halawa-School circuits.

To mitigate the reactive power shortfall at Archer Substation, analysis was performed with Honolulu 8 and 9 synchronous condensers added to the system.

Unit	Unit Ratings		Theme 5 - QV MVAR Capability Mon 8/5/19 Hour 13		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.8	33.2	-2.8
HPOWER-2	28.0	-16.0	2.8	25.2	-18.8
AES	99.4	-49.8	29.3	70.1	-79.1
Kalaeloa CT-1	84.5	-35.9	15.6	68.9	-51.5
Kalaeloa ST	84.5	-35.8	15.6	68.9	-51.4
Kalaeloa CT-2	42.1	-16.7	15.6	26.5	-32.3
Kahe 1	71.0	-52.0			
Kahe 2	68.3	-51.6	31.8	36.5	-83.4
Kahe 3	73.7	-24.3	31.8	41.8	-56.2
Kahe 4	67.7	-24.1	31.8	35.8	-55.9
Kahe 5	117.8	-71.3	100.9	17.0	-172.2
Kahe 6	111.8	-64.2			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	21.1	29.9	-54.1
Hon 9 (Sync Cond)	51.0	-33.0	21.1	29.9	-54.1
Total Wind	87.4	-110.9	16.3	71.1	-127.2
-Kahuku	17.9	-17.9	6.3	11.6	-24.1
-Kawailoa	50.0	-74.5	7.9	42.1	-82.4
-Na Pua Makani	16.4	-15.4	2.1	14.3	-17.5
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	0.0	0.0			
-Offshore Wind	0.0	0.0			
Total Station PV	109.4	-109.4	13.5	95.9	-123.0
-KS2	1.6	-1.6	1.6	0.0	-3.3
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	3.2	11.3	-17.7
-Kawailoa PV	36.8	-36.8	-0.4	37.2	-36.3
-Mililani 2	10.7	-10.7	0.3	10.4	-11.0
-Waiawa	32.9	-32.9	3.3	29.6	-36.2
-Westloch	6.3	-6.3	3.5	2.8	-9.7
-CBRE PV	4.7	-4.7	0.1	4.6	-4.8
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			320.2		
Total Renewable MVAR Generation			29.8		
Total Cap Bank MVAR			183.6		
Charging MVAR			77.2		
Total MVAR Supply			610.8		
Total MVAR Load			411.0		
Total MVAR Losses			199.9		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				650.8	
Total MVAR Absorb Capability					-928.9

Table O-14. MVAR Capability QV Sensitivity Analysis

Table O-14 shows the MVAR capability from the generating resources from the unit commitment and dispatch with the addition of Honolulu 8 and 9 synchronous condensers, increasing the system's reactive power capacity by 60 MVAR.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1

Table O-15. N-2 Contingencies QV Sensitivity

Table O-15 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

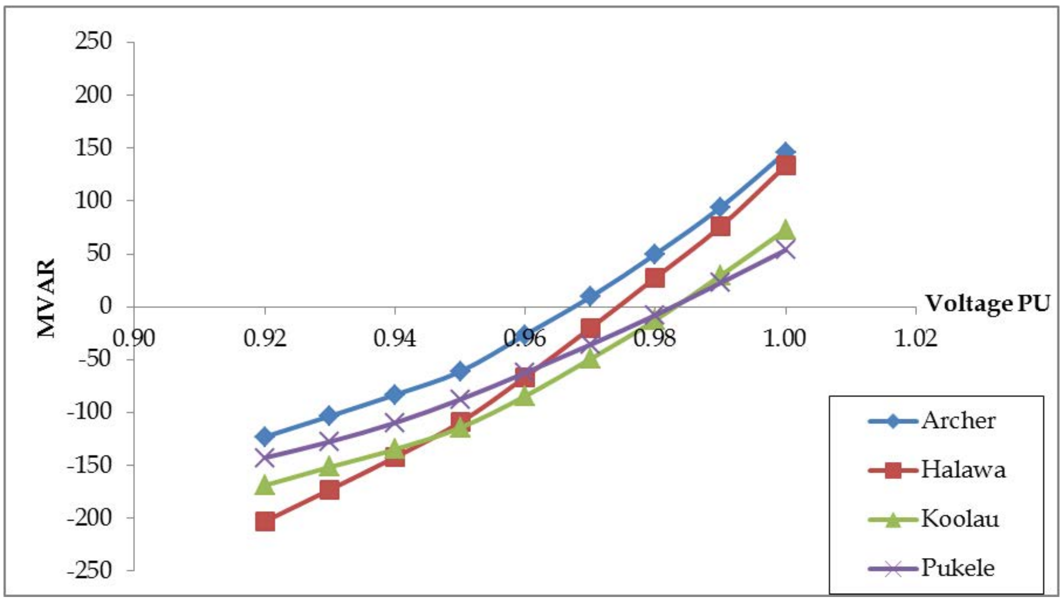

Figure O-16. QV Curves with H8 & H9 Synchronous Condensers

Figure O-16 shows the QV curves for the Archer, Halawa, Koʻolau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation is able to maintain bus voltage at 0.95 PU with the additional 60 MVAR of reactive power from the Honolulu 8 and 9 synchronous condensers.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	146	154	94	154	50	135	9	135	-26	135	-61	135	-83	135	-103	135	-123
120	Halawa	125	134	154	76	154	28	154	-20	154	-66	154	-109	154	-142	154	-173	154	-203
150	Koolau	125	73	125	30	125	-12	125	-49	125	-84	125	-114	203	-135	203	-151	203	-169
170	Pukele	125	54	125	23	125	-8	125	-36	125	-62	125	-88	125	-110	203	-128	203	-143

Table O-16. QV Analysis Summary of Results H8 & H9 Synchronous Condensers

Table O-16 shows the results of the QV analysis with the Honolulu 8 and 9 synchronous condensers. The unit commitment and dispatch in conjunction with the Honolulu 8 and 9 synchronous condensers are able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Analysis was performed on two hours from the Theme 5 production simulation data that represent a typical and a boundary condition.

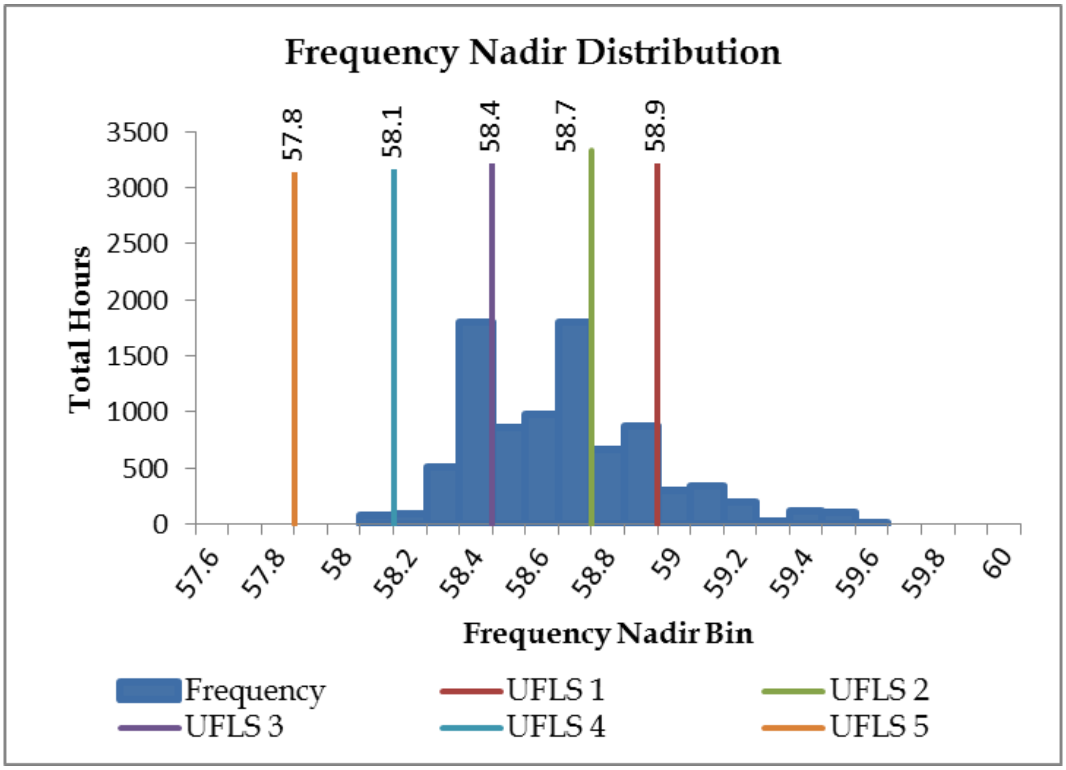

Figure O-17. Frequency Nadir Histogram for 2019

Figure O-17 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production simulation data. The typical hour was selected from the maximum distribution of 1797 hours was 12:00 PM on Monday, June 10. The frequency nadir range for the typical hour is 58.3 - 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 60 hours was 11:00 AM on Monday, May 27. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

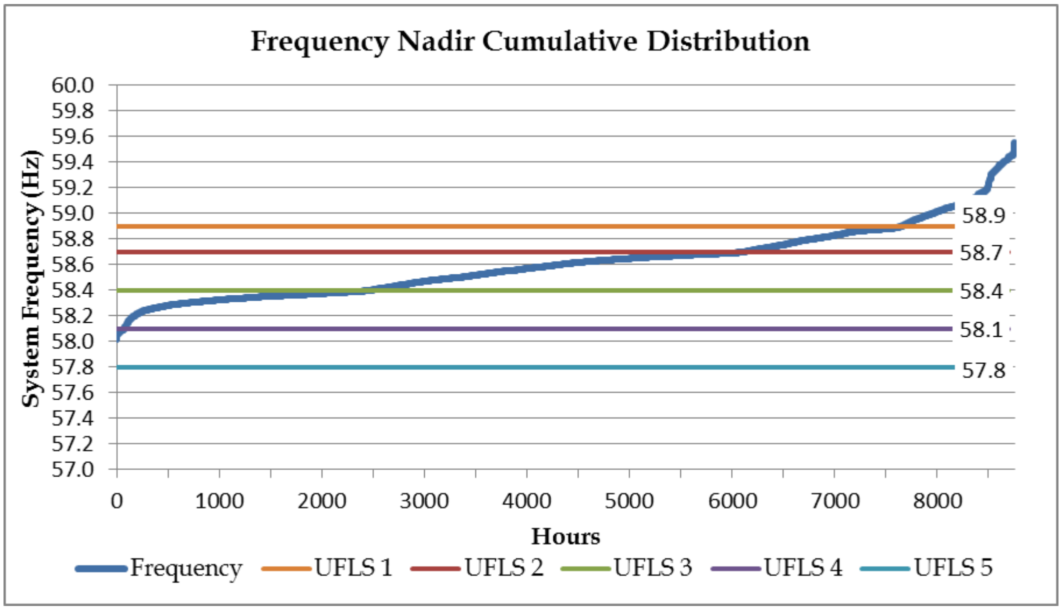

Figure O-18. Frequency Nadir Duration Curve 2019

Figure O-18 shows the frequency nadir duration curve for the Theme 5 resource plan in 2019. The system is at risk of UFLS for 7661 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Mon 10/14/19 Hour 11			Theme 5 - AES Trip Boundary Fri 11/29/19 Hour 12		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.2	10.8	10.2	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	72.2	11.8	43.2	48.7	35.3	19.7
Kalaeloa ST	40.0	10.0			4.70	61.1	287	34.4	5.6	24.4	23.2	16.8	13.2
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	72.2	11.8	43.2	48.7	35.3	19.7
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	22.9	111.7	1.9	21.0	113.6	0.0
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	25.0	58.3	1.2			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						32			38		
-Kahuku	30	0						4			4		
-Kawailoa	69	0						9			17		
-Na Pua Makani	24	0						18			14		
-CBRE Wind	10	0						1			3		
DG-PV	701	0						396			383		
Station PV	183	0						136			121		
Total Kinetic Energy									4518			3735	
Total Load									1074			961	
Total Thermal Generation									511			419	
Total Renewable Generation									564			541	
Total Generation									1074			960	
Excess Generation									0			0	
Total Up Regulation									344			267	
Total Down Regulation									253			209	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		41.5	59.3Hz Output		40.2
	60.5Hz Capacity			215.9				60.5Hz Output		121.9	60.5Hz Output		118.0

Table O-17. Commitment and Dispatch 2019

Table O-17 shows the unit commitment and dispatch for the typical hour (10/14/19, 11:00 AM) and boundary hour (11/29/19, 12:00 PM).

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

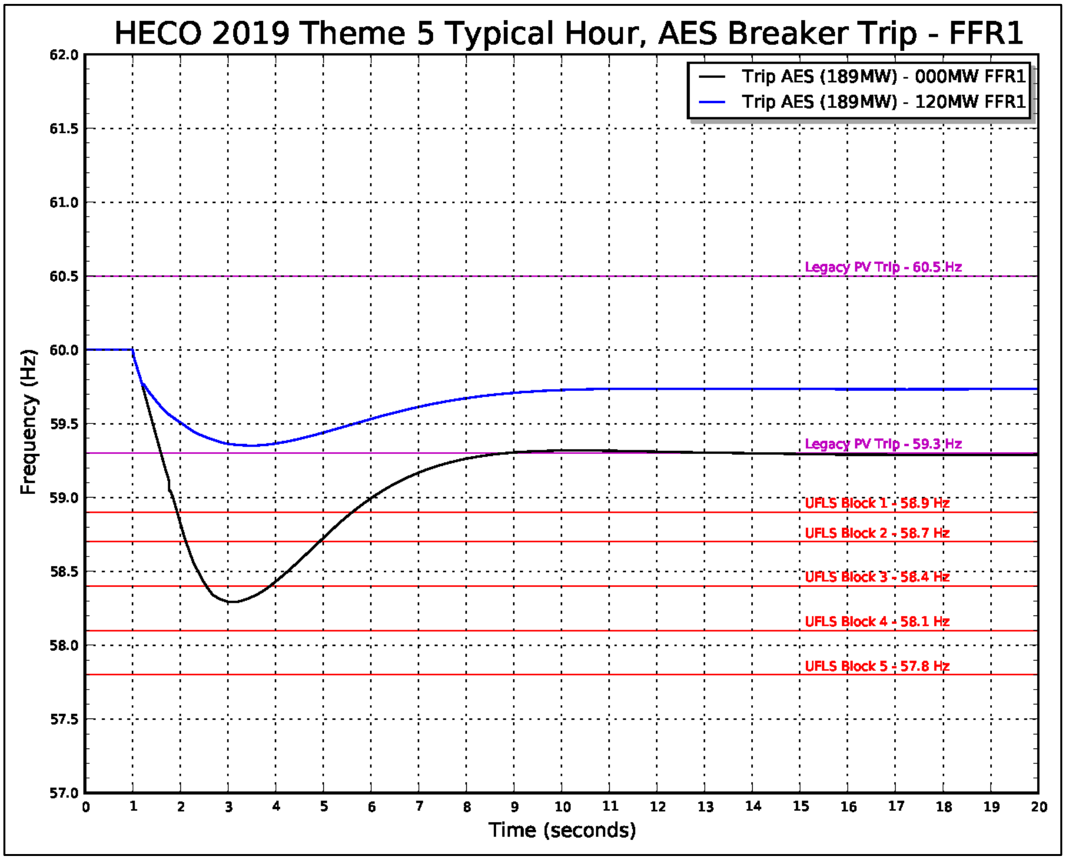

Figure O-19. Frequency Response Profile for FFR1 Typical Hour

Figure O-19 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 4518 MW-sec and the capacity of legacy PV that will disconnect from the system is 41.5 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

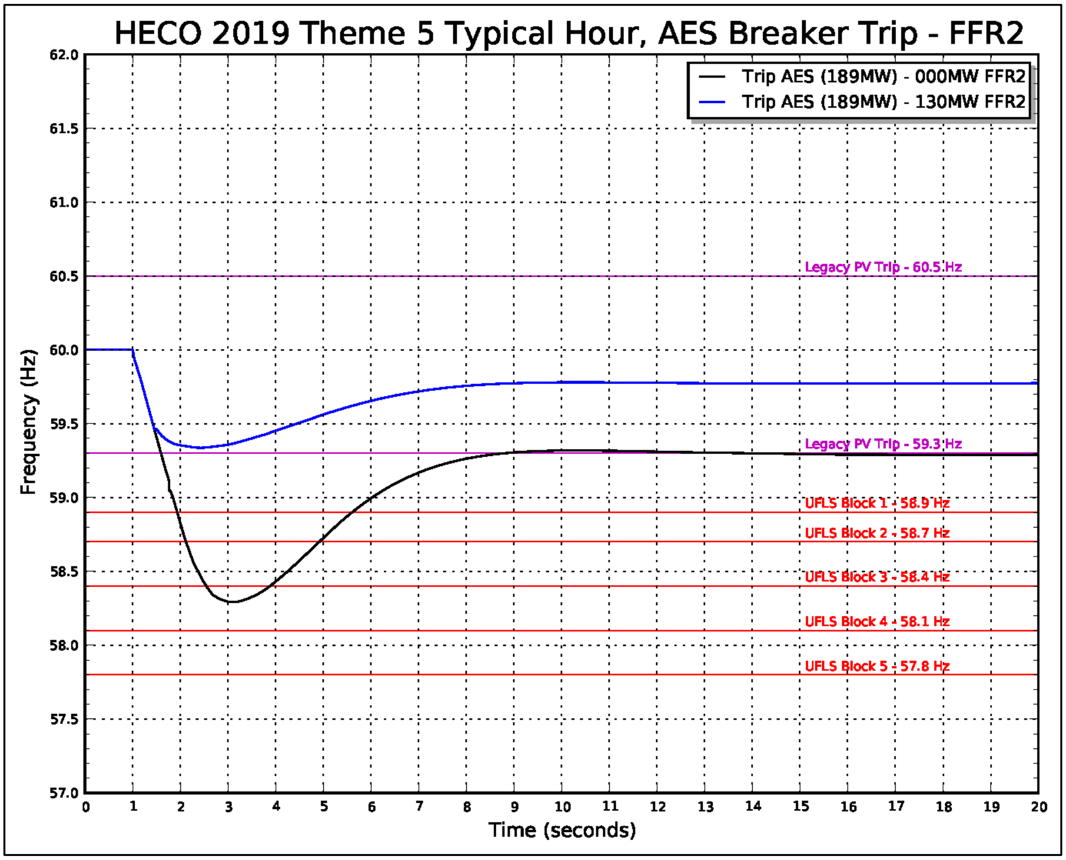

Figure O-20. Frequency Response Profile for FFR2 Typical Hour

Figure O-20 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

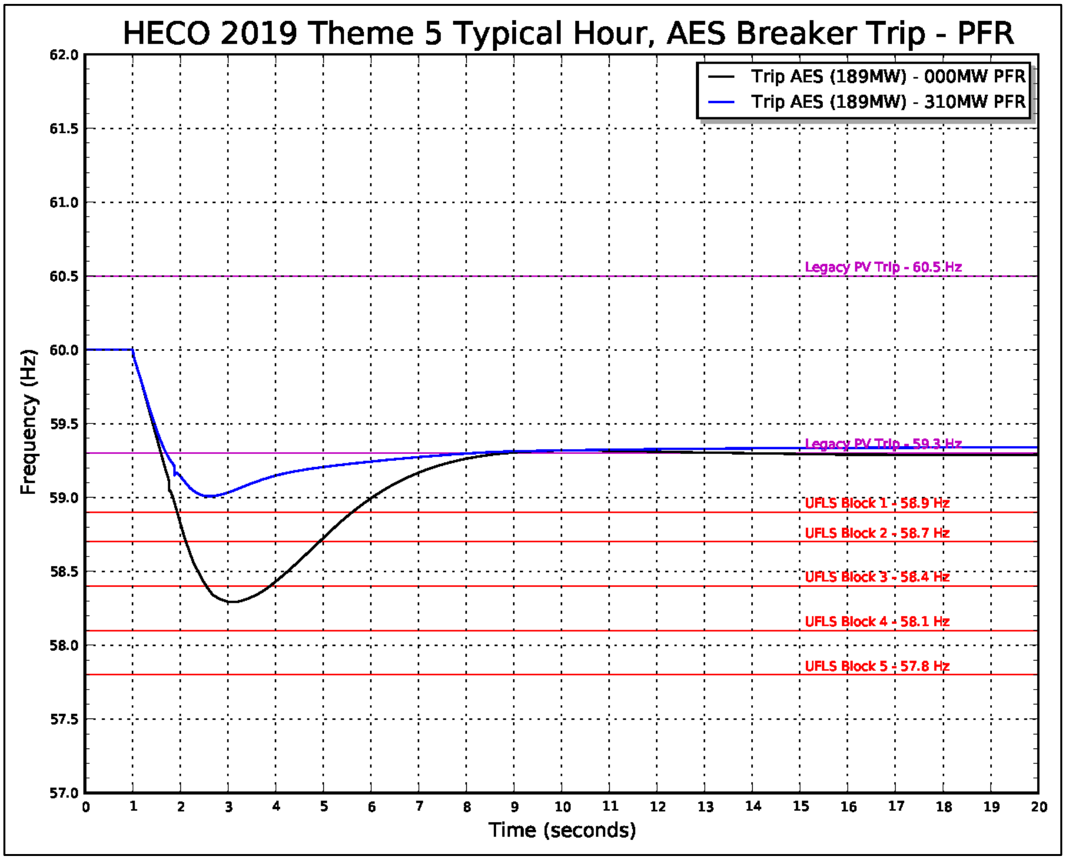

Figure O-21. Frequency Response Profile for PFR Typical Hour

Figure O-21 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 310 MW. This is in addition to the 368 MW of upward regulation from thermal generation.

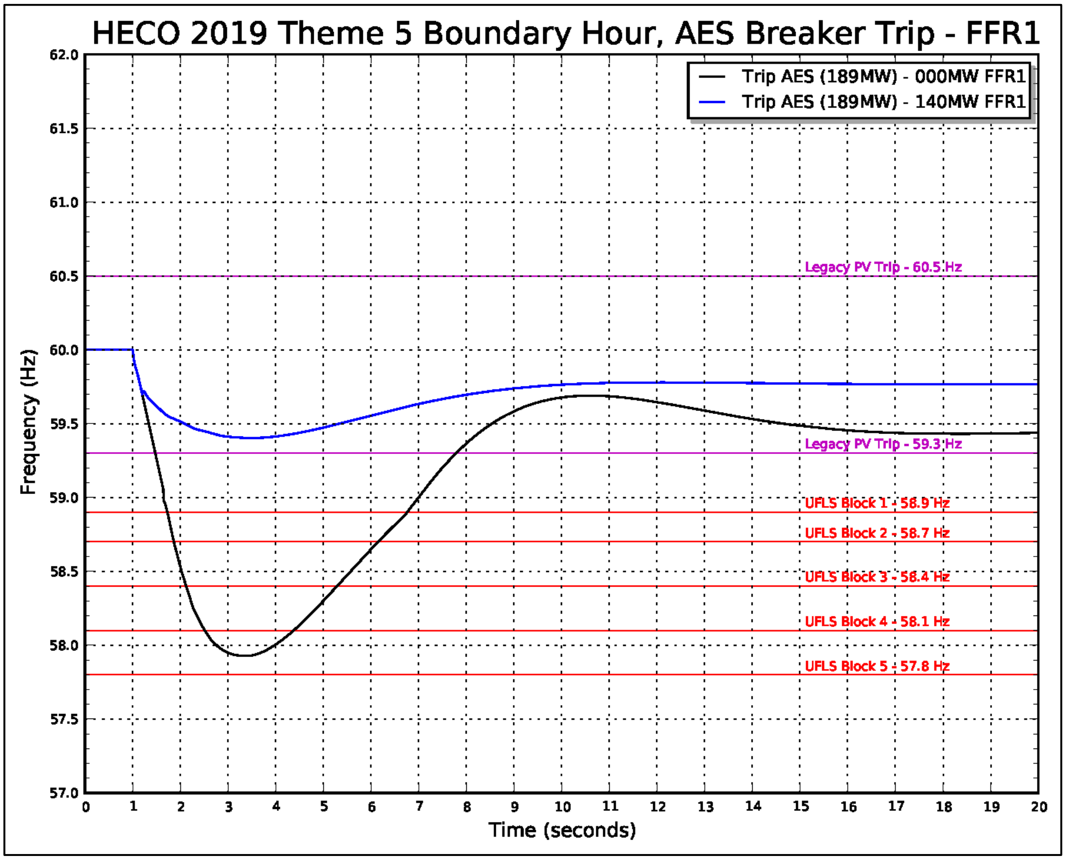

Figure O-22. Frequency Response Profile for FFR1 Boundary Hour

Figure O-22 shows the frequency response profile for an AES trip at 179 MW for a boundary hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.2 MW. With no FFR, the frequency nadir is 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

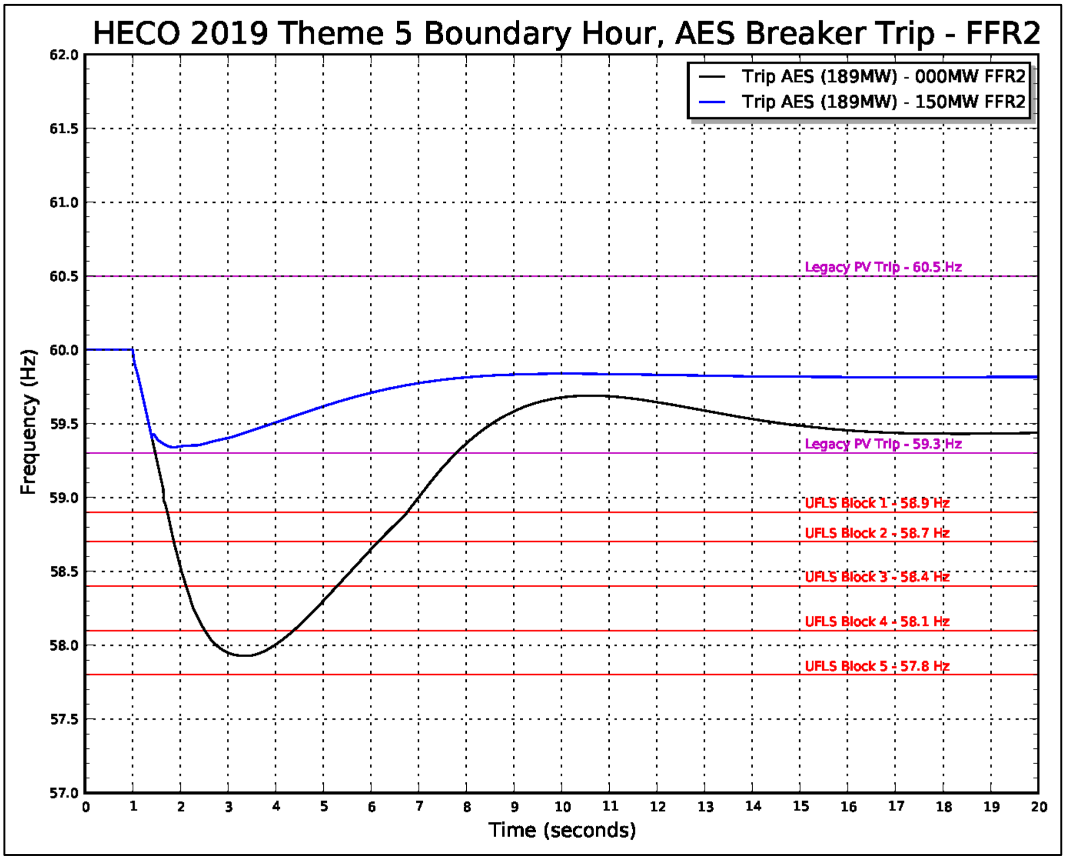

Figure O-23. Frequency Response Profile for FFR2 Boundary Hour

Figure O-23 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

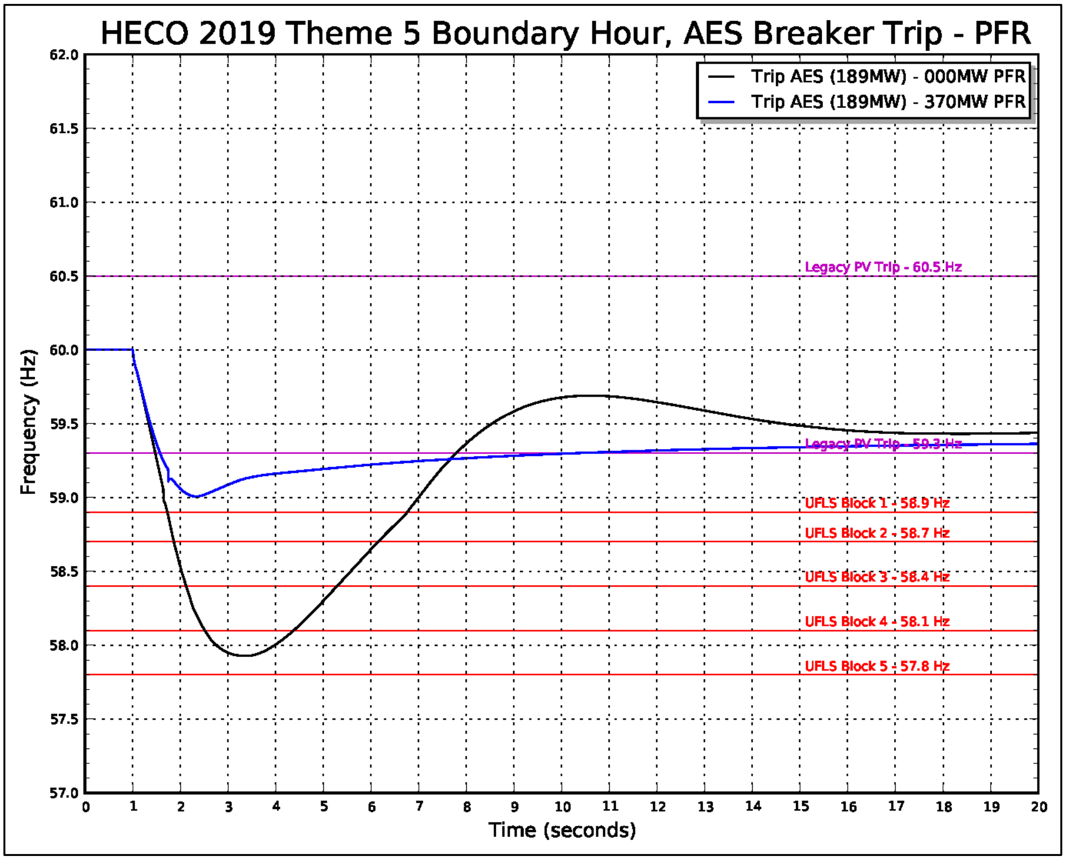

Figure O-24. Frequency Response Profile PFR Boundary Hour

Figure O-24 shows the frequency response profile for the PFR analysis. The capacity of PFR to meet TPL-001 is 370 MW. This is in addition to the 226 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Wed 6/12/19 Hour 11			Theme 5 - K5 Trip Boundary Fri 11/29/19 Hour 12		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	98.0	91.0	35.0	75.0	114.0	12.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	83.8	0.2	54.8	48.7	35.3	19.7
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.9	0.1	29.9	23.2	16.8	13.2
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	83.8	0.2	54.8	48.7	35.3	19.7
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	42.2	44.0	18.5	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	133	0						31			38		
-Kahuku	30	0						3			4		
-Kawailoa	69	0						11			17		
-Na Pua Makani	24	0						15			14		
-CBRE Wind	10	0						2			3		
DG-PV	701	0						261			383		
Station PV	183	0						111			121		
Total Kinetic Energy									4092			3735	
Total Load									975			961	
Total Thermal Generation									571			419	
Total Renewable Generation									404			541	
Total Generation									975			960	
Excess Generation									0			0	
Total Up Regulation									200			267	
Total Down Regulation									337			208	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		27.4	59.3Hz Output		40.2
	60.5Hz Capacity			215.9				60.5Hz Output		80.5	60.5Hz Output		118.0

Table O-18. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-18 shows the unit commitment and dispatch for the typical hour (6/12/19, 11:00 AM) and boundary hour (11/29/19, 12:00 PM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

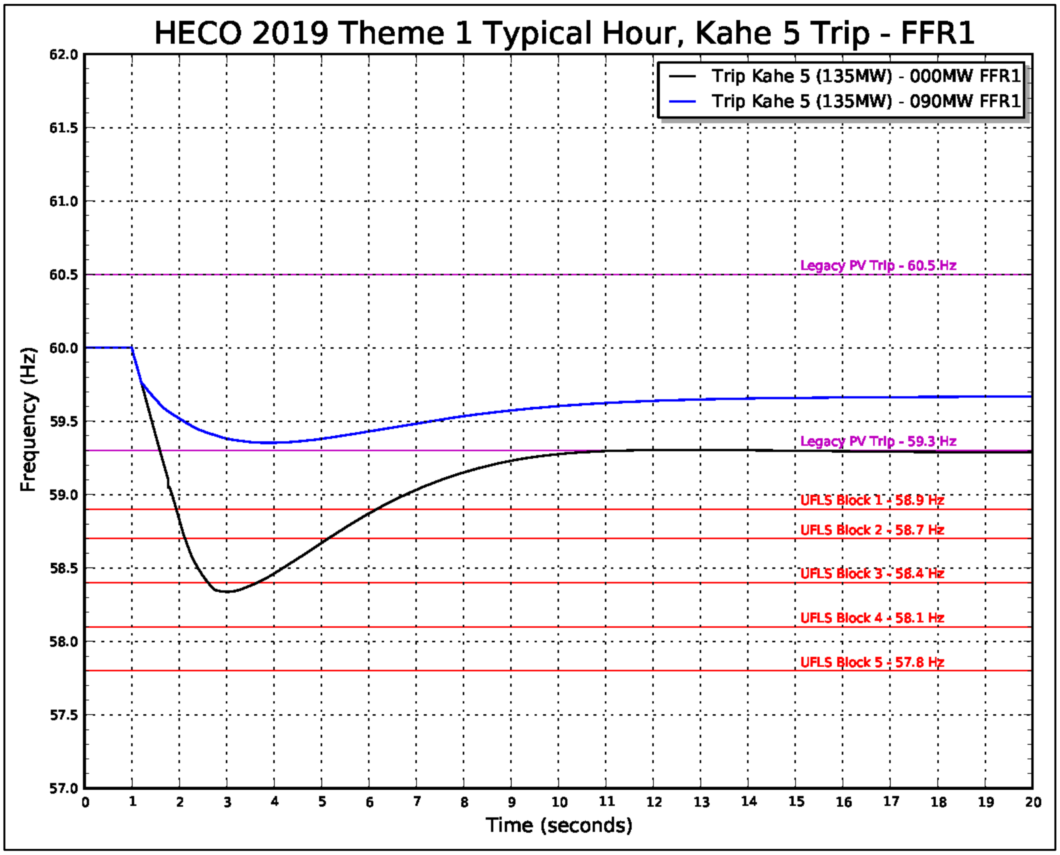

Figure O-25. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-25 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4092 MW-sec and the capacity of legacy PV that will disconnect from the system is 27.4 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW.

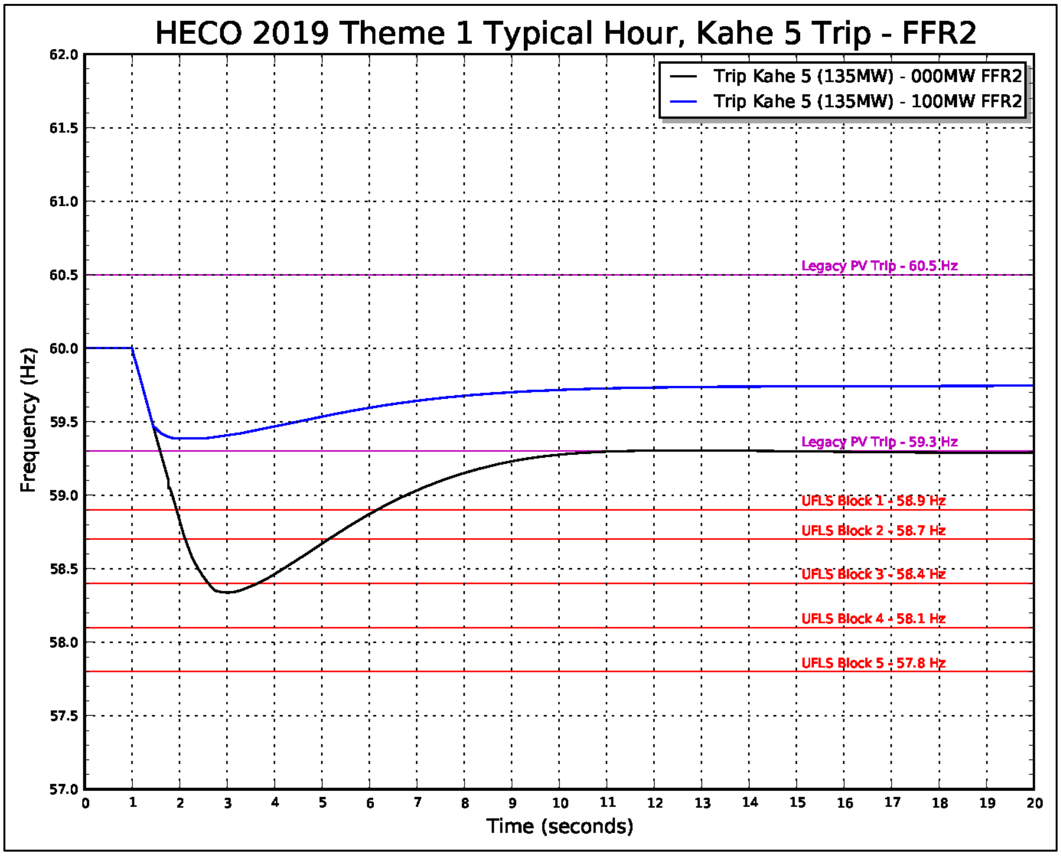

Figure O-26. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-26 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

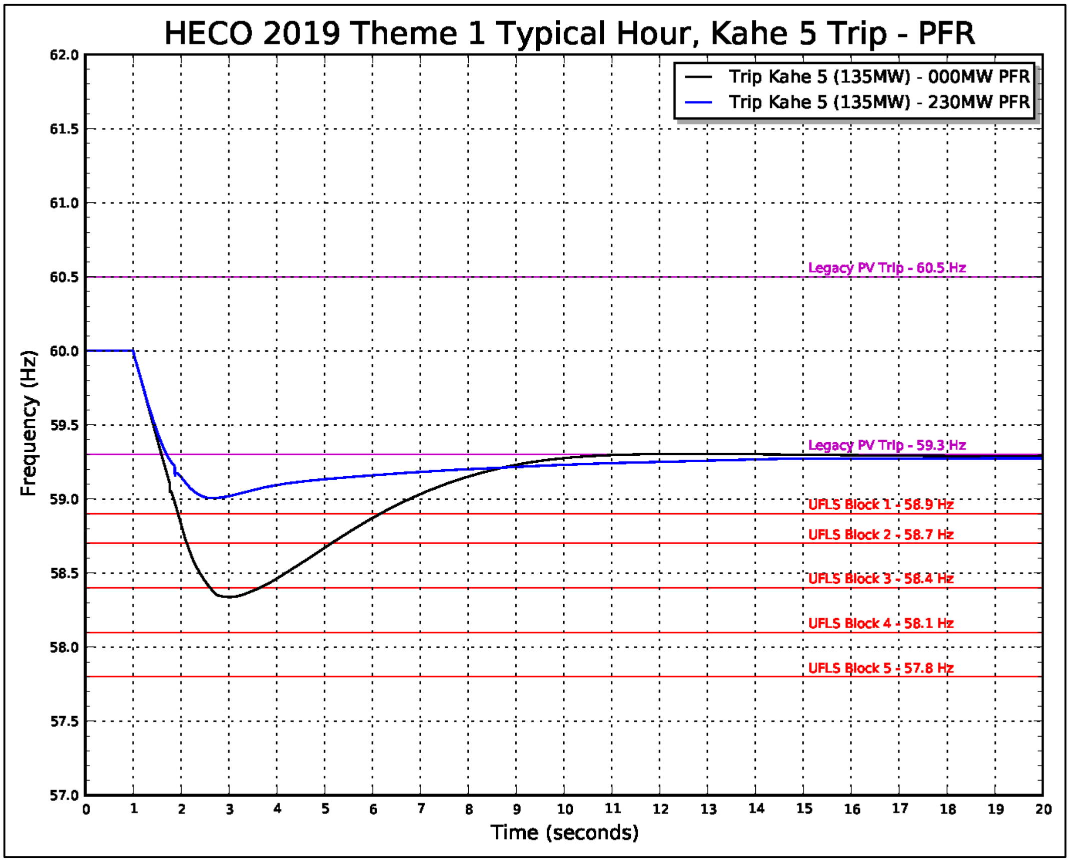

Figure O-27. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-27 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 230 MW. This is in addition to the 216 MW of upward regulation from thermal generation.

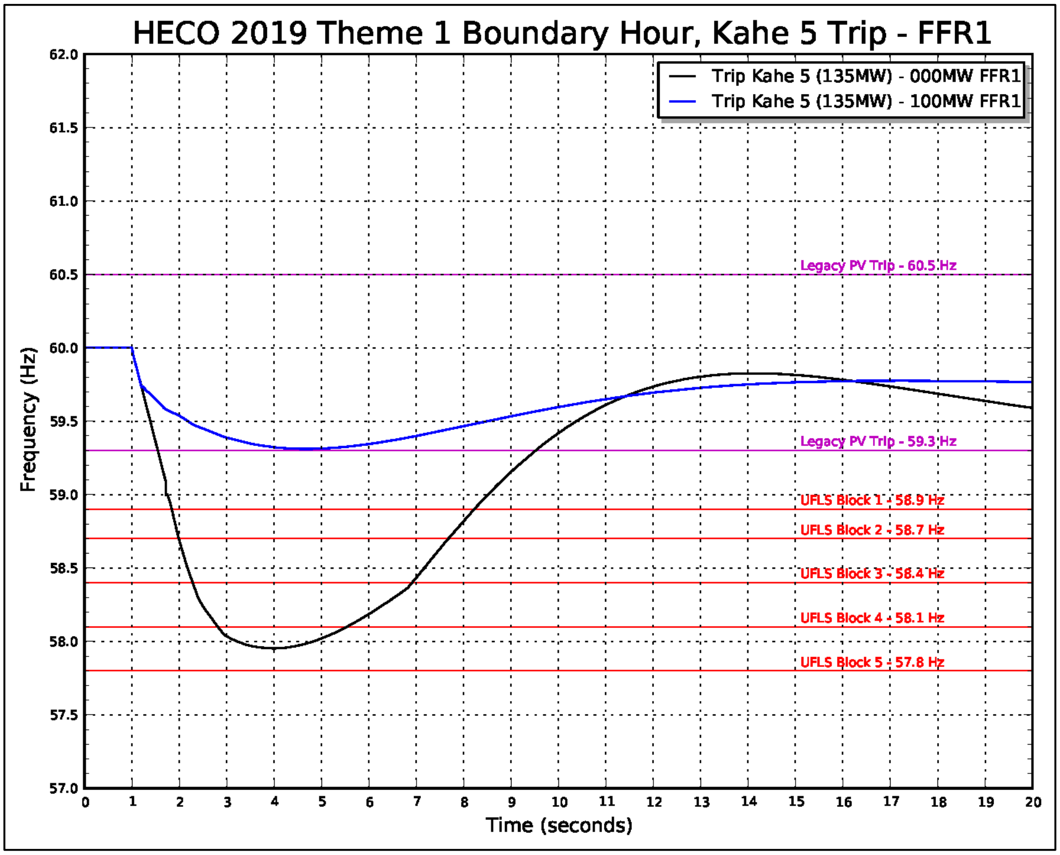

Figure O-28. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-28 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.2 MW. With no FFR, the frequency nadir is 57.9 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

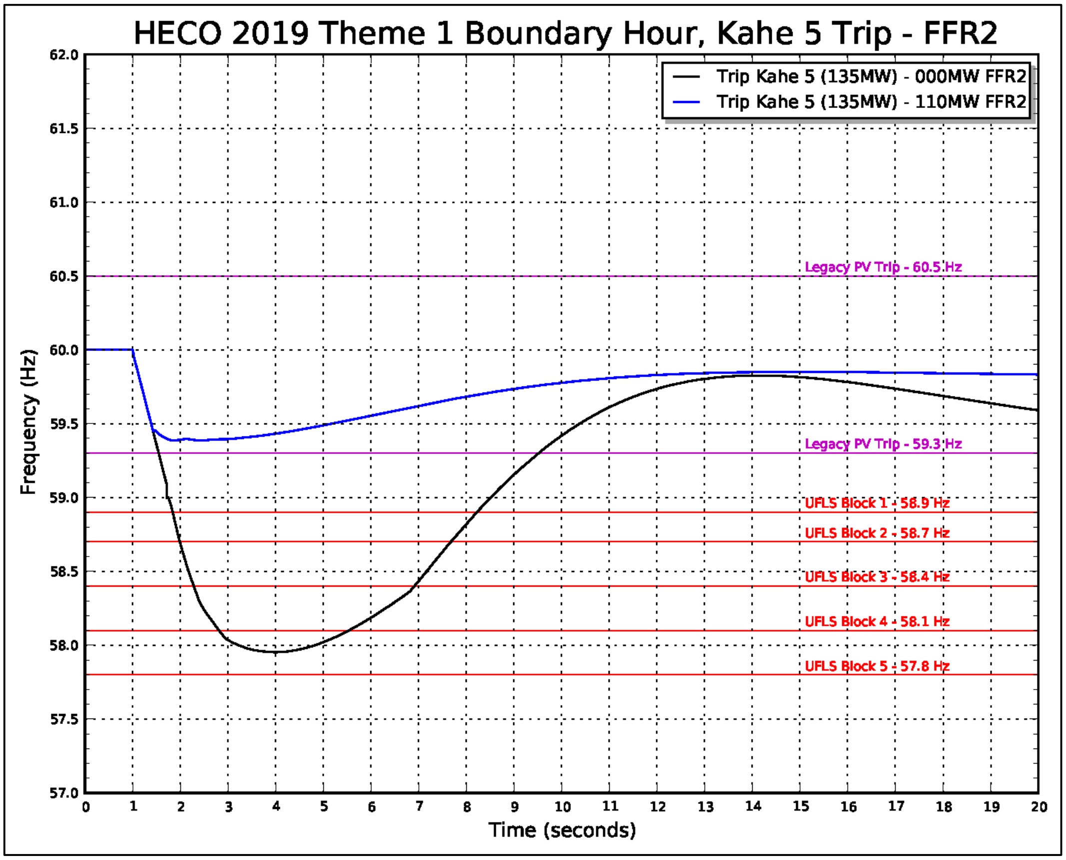

Figure O-29. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-29 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 110 MW.

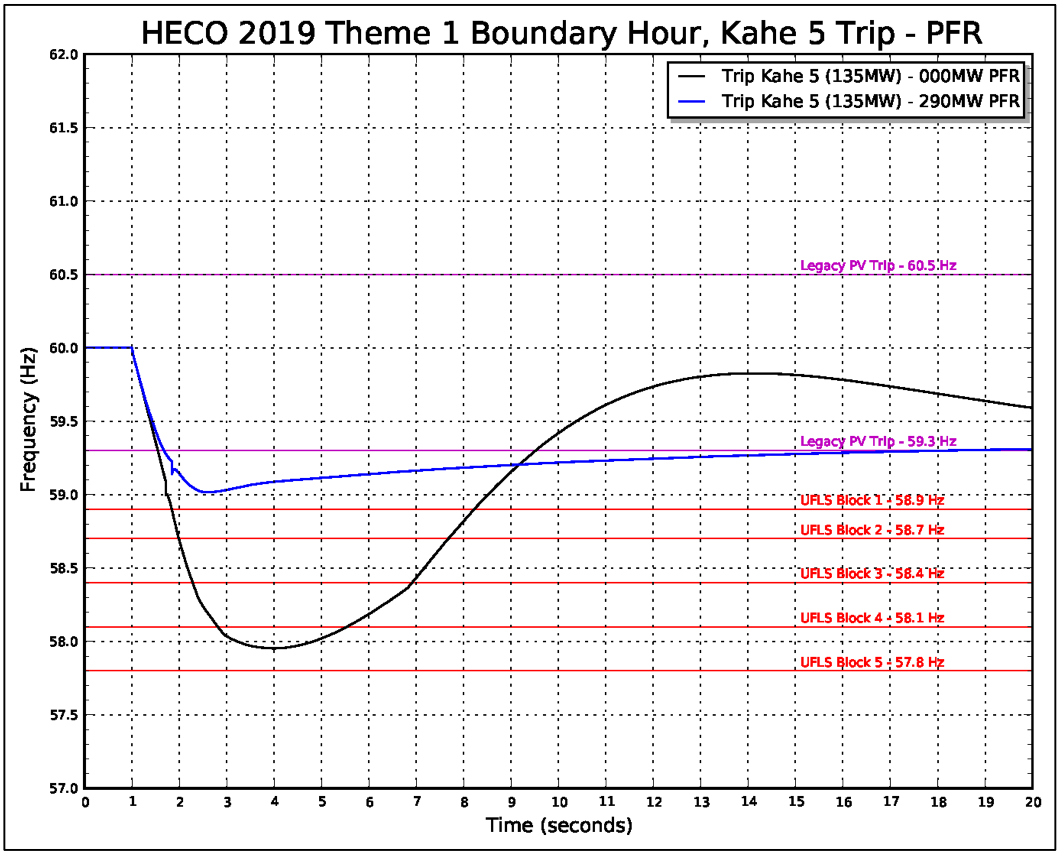

Figure O-30. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-30 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 290 MW. This is in addition to the 226 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							Theme 5 - Fault Sun 6/9/19 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	27.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357			
Kahe 5	134.6	21.0			4.36	158.8	692	21.0	113.6	0.0
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	133	0						58		
-Kahuku	30	0						16		
-Kawailoa	69	0						24		
-Na Pua Makani	24	0						15		
-CBRE Wind	10	0						3		
DG-PV	662	0						529		
Station PV	187	0						158		
Total Kinetic Energy									3144	
Total Load									983	
Total Thermal Generation									238	
Total Renewable Generation									745	
Total Generation									983	
Excess Generation									0	
Total Up Regulation									365	
Total Down Regulation									56	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		58.8
	60.5Hz Capacity			215.9				60.5Hz Output		172.7

Table O-19. Unit Commitment and Dispatch Fault Analysis

Table O-19 shows the unit commitment and dispatch for the fault analysis.

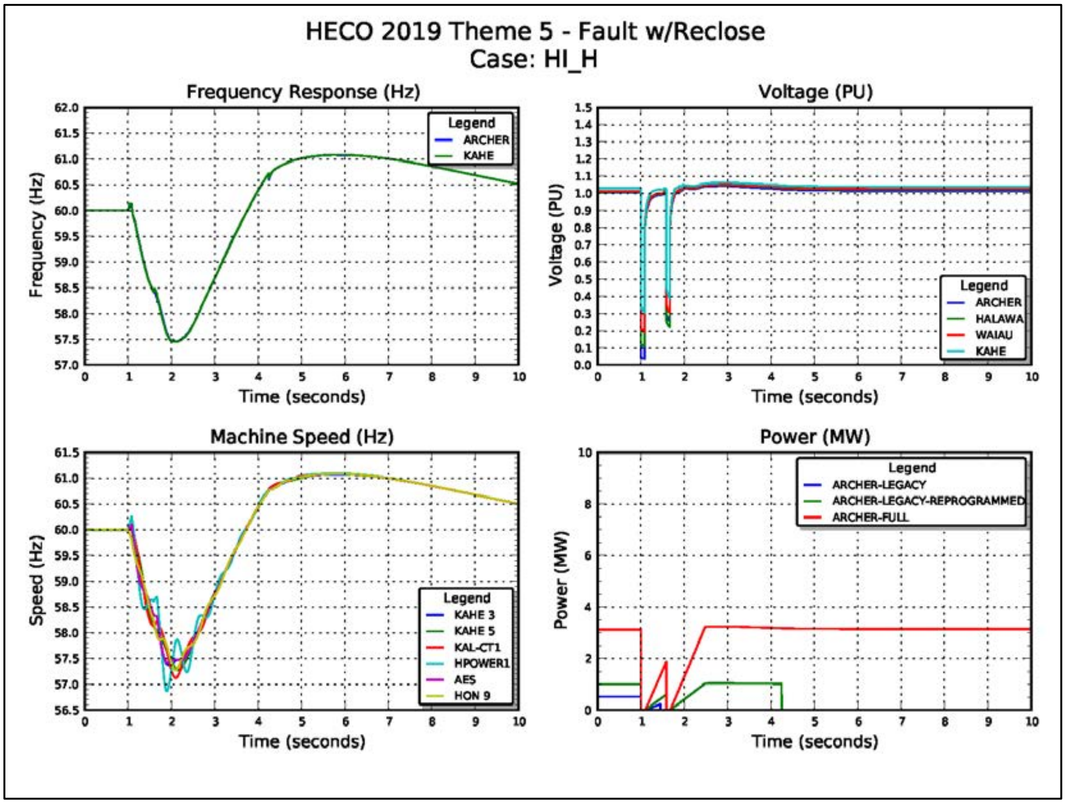

Figure O-31. System Performance for Normally Cleared Fault

Figure O-31 shows the system performance for a normally cleared fault on the Halawa-Iwilei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 687 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from DG-PV is restored but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 57.5 Hz and avoid system collapse but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Archer Substation that is indicative of DG-PV performance across the entire system. The under frequency trip protection for most synchronous units is initiated at 57.0 Hz and the frequency nadir for this contingency is 57.5 Hz, providing a 0.5 Hz margin.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet TPL-001.

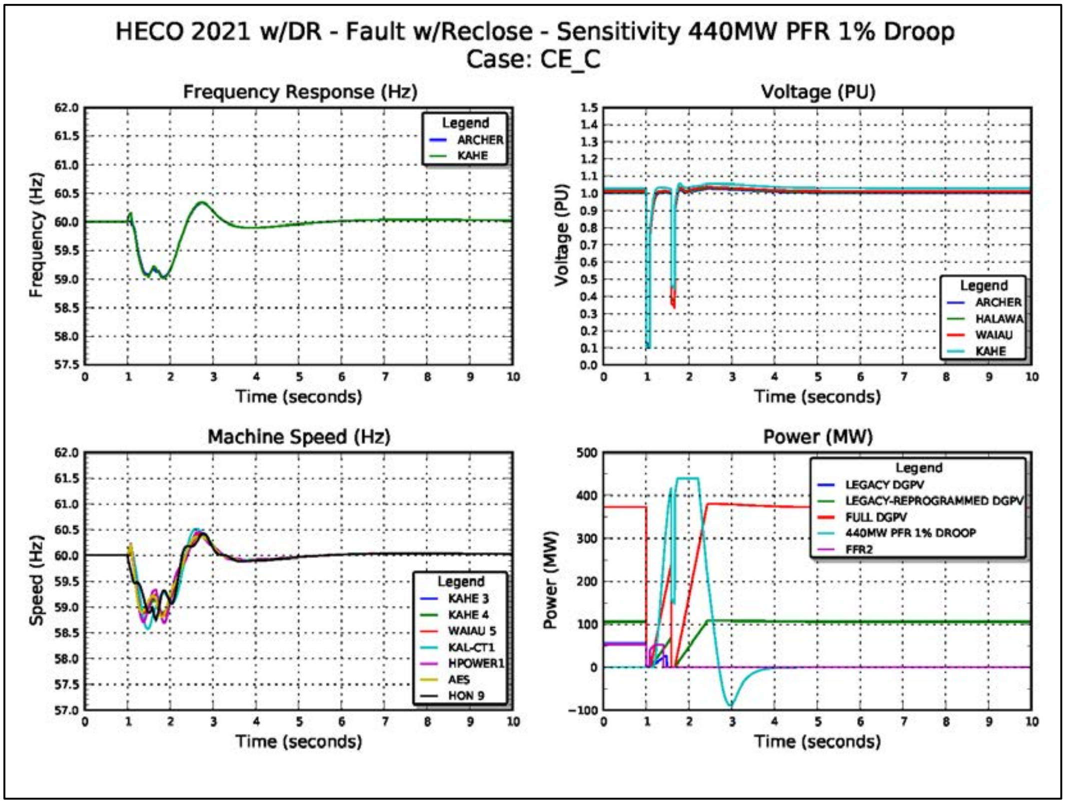

Figure O-32. Normally Cleared Fault Sensitivity 440 MW PFR

Figure O-32 shows system performance with the addition of 440 MW of PFR at 1% droop response. For the purpose of this analysis, a 440 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, demand response, 440 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

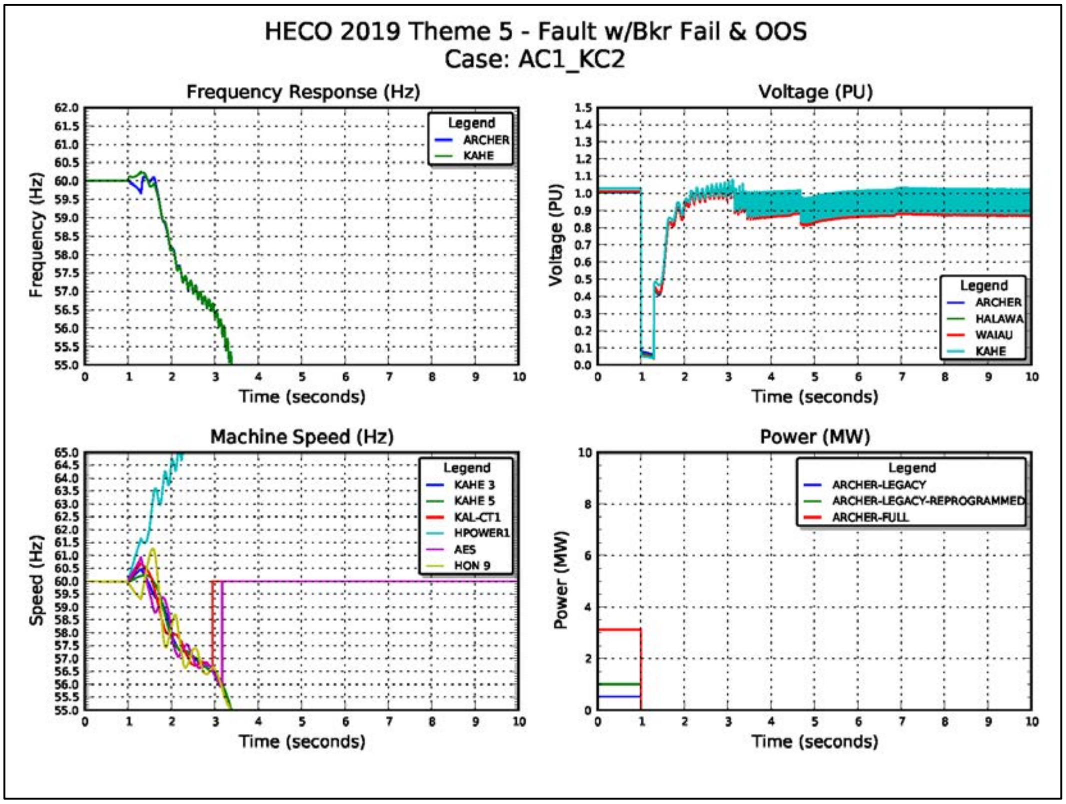

Figure O-33. System Performance for Breaker Failure Analysis

Figure O-33 shows four plots that illustrate system performance for a fault on the AES-CEIP 1 circuit and BKR 276 fails to operate. A breaker failure initiates the backup protection scheme to clear the fault, isolating the Kahe-CEIP2 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through setting for longer than 0.5 seconds, causing 687 MW of inverter-based generation to trip offline. System frequency decays below 56.0 Hz so the remaining synchronous generators trip offline on under frequency protection, causing the system to collapse. Note that HPOWER 1 loses synchronism almost immediately after the fault, indicating the delayed clearing exceeded its critical clearing time for stability. Further analysis is required to determine if HPOWER 1 requires out-of-step protection.

Fifteen breaker failure simulations resulted in system instability and/or collapse. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize system frequency. The analysis was performed for AES-CEIP 1 circuit only.

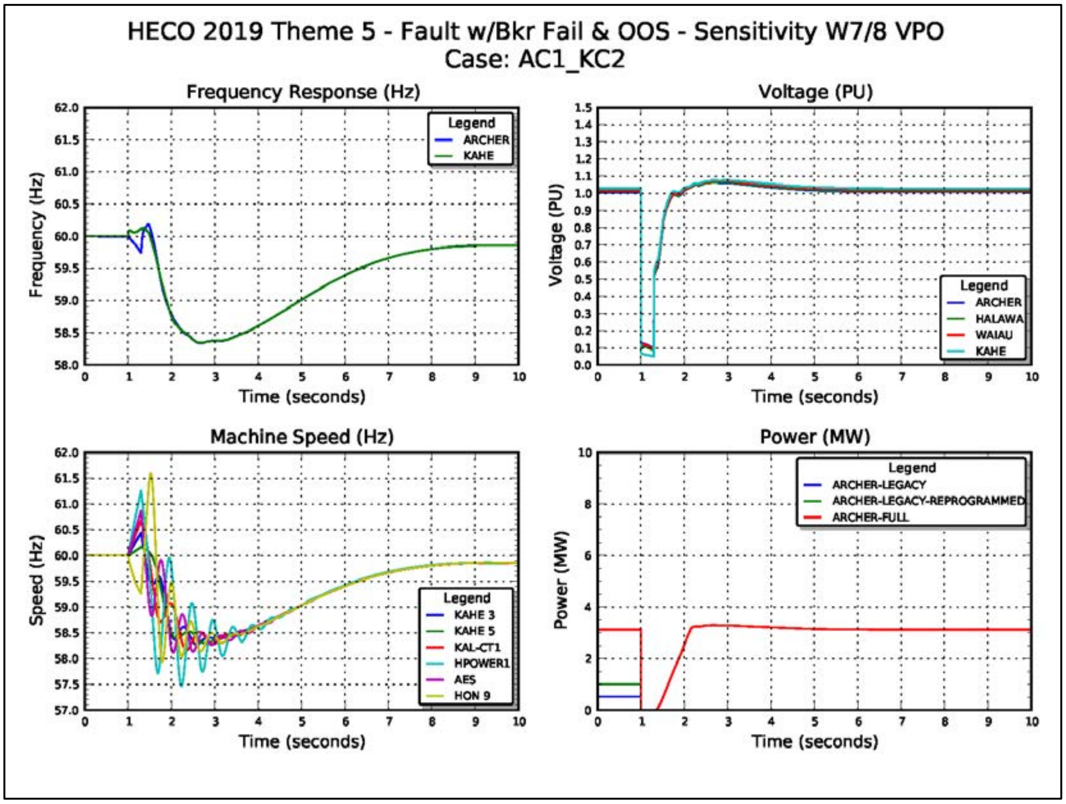

Figure O-34. Breaker Failure Sensitivity VPO Units

Figure O-34 shows system performance with the Waiau Units 7 and 8 operating in VPO. This adds inertia, short circuit current, voltage support/MVAR capability, and increases the magnetic strength of the system. A unit committed in VPO provides limited frequency response reserves.

System voltage is momentarily suppressed but recovers above the 0.5 PU threshold before the 0.5 second trip setting. The aggregate response from synchronous units, the restoration of full ride-through DG-PV generation, and four blocks of UFLS stabilizes system frequency at 58.4 Hz. The system is stable but does not meet the requirements of TPL-001. Further analysis is required to determine an optimal strategy to address this issue.

2019 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Fault Hour Condition	Waiau 7/8 VPO Mitigation
AES-CEIP 1	AES	320	15	AES-HP	Unstable	Stable
AES-HP	AES	320	15	AES-CEIP 1	Unstable	Stable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Unstable
AES-Kalaeloa	AES	456	15	CIP Gen	Unstable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Unstable	Stable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Unstable	Stable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Unstable	Stable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Unstable	Stable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Unstable	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Unstable	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Unstable	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Unstable	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Unstable	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Unstable	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Unstable	Unstable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-20. Summary of Results Breaker Failure Analysis

Table O-20 is the summary of results for the breaker failure analysis. Fifteen simulations resulted in system instability where HPOWER 1 lost synchronism and/or system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to trip. Committing Waiau 7 and 8 in VPO stabilized all but two breaker failure simulations.

Multiple blocks of UFLS were required to stabilize system frequency for normally cleared faults. The system requires 440 MW of PFR at 1% droop response to meet TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O'ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko'olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							Theme 5 - QV Dispatch Mon 10/5/20 Hour 16		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	35.0	5.0	25.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	82.0	2.0	53.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	44.0	38.2	20.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	44.0	38.2	20.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	47.0	39.2	23.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	55.0	30.3	31.4
Kahe 5	134.6	21.0			4.36	158.8	692	107.0	27.6	86.0
Kahe 6	133.8	40.0			4.36	158.8	692	71.0	62.8	31.0
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163.0	0.0						24.0		
-Kahuku	30.0	0.0						0.0		
-Kawailoa	69.0	0.0						8.0		
-Na Pua Makani	24.0	0.0						0.0		
-CBRE Wind	10.0	0.0						4.0		
-Future Wind	30.0	0.0						12.0		
-Offshore Wind	0.0	0.0								
Total Station PV	362.2	0.0						208.0		
-KS2	5.0	0.0						2.0		
-KREP	5.0	0.0						1.0		
-Waianae	27.6	0.0						12.0		
-Kawailoa PV	49.0	0.0						23.0		
-Mililani 2	14.7	0.0						8.0		
-Waiawa	45.9	0.0						24.0		
-Westloch	20.0	0.0						14.0		
-CBRE PV	15.0	0.0						10.0		
-Future PV	180.0	0.0						114.0		
DG-PV	749.0	0.0						214.0		
Total Kinetic Energy									5637	
Total Load									1247	
Total Thermal Generation									801	
Total Renewable Generation									446	
Total Generation									1247	
Excess Generation									0	
Total Up Regulation									269	
Total Down Regulation									479	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		21.0
	60.5Hz Capacity			215.9				60.5Hz Output		61.7

Table O-21. Unit Commitment and Dispatch 2020 QV Analysis

Table O-21 shows the unit commitment and dispatch for the 2020 QV analysis.

Unit	Unit Ratings		Theme 5 - QV MVAR Capability Mon 10/5/20 Hour 16		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	5.4	30.6	-5.4
HPOWER-2	28.0	-16.0	5.4	22.6	-21.4
AES	99.4	-49.8	34.1	65.3	-83.9
Kalaeloa CT-1	84.5	-35.9	20.2	64.3	-56.1
Kalaeloa ST	84.5	-35.8	20.2	64.3	-56.0
Kalaeloa CT-2	42.1	-16.7	20.2	21.9	-36.9
Kahe 1	62.9	-49.7	20.4	42.5	-70.1
Kahe 2	62.9	-49.7	20.4	42.5	-70.1
Kahe 3	68.3	-18.3	20.4	47.9	-38.7
Kahe 4	60.6	-16.3	20.4	40.2	-36.7
Kahe 5	91.9	-61.3	94.9	-3.0	-156.2
Kahe 6	106.6	-61.3	38.6	68.0	-99.9
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	26.0	25.0	-59.0
Hon 9 (Sync Cond)	51.0	-33.0	26.0	25.0	-59.0
Total Wind	96.7	-120.3	13.4	49.1	-100.3
-Kahuku	17.9	-17.9			
-Kawailoa	50.0	-74.5	13.3	36.7	-87.8
-Na Pua Makani	16.4	-15.4			
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.1	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	234.4	-234.4	22.8	211.6	-257.2
-KS2	1.6	-1.6	1.3	0.4	-2.9
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	2.5	12.0	-17.0
-Kawailoa PV	36.8	-36.8	-0.9	37.7	-35.8
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.4
-Waiawa	32.9	-32.9	1.2	31.6	-34.1
-Westloch	6.3	-6.3	3.3	3.0	-9.5
-CBRE PV	4.7	-4.7	0.0	4.6	-4.7
-Future PV	125.0	-125.0	13.6	111.4	-138.6
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			372.7		
Total Renewable MVAR Generation			36.2		
Total Cap Bank MVAR			184.2		
Charging MVAR			76.5		
Total MVAR Supply			669.5		
Total MVAR Load			404.6		
Total MVAR Losses			264.9		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				817.8	
Total MVAR Absorb Capability					-1207.0

Table O-22. MVAR Capability 2020 QV Analysis

Table O-22 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-23. N-2 Contingencies 2020

Table O-23 shows the N-2 contingencies that were simulated in the QV analysis. These contingencies have the biggest impact to MVAR requirements for the critical busses.

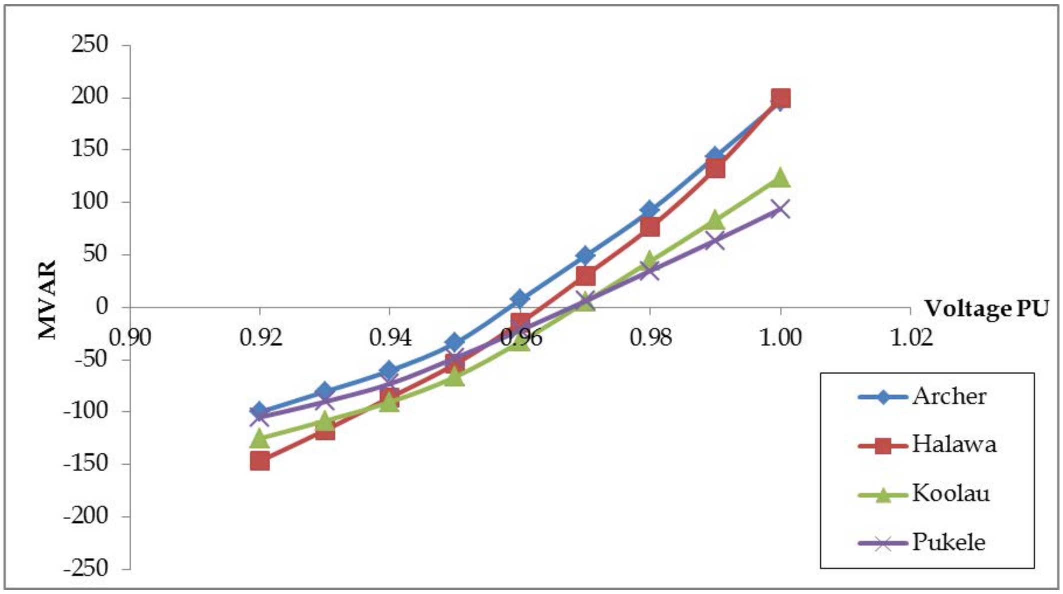

Figure O-35. QV Curves 2020

Figure O-35 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. The unit commitment and dispatch with Honolulu 8 and 9 synchronous condensers meets the reactive power requirements of the system under N-2 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	196	125	144	125	92	154	49	154	7	154	-34	135	-60	135	-80	135	-100
120	Halawa	125	200	125	132	154	76	154	30	154	-15	154	-54	154	-86	154	-117	154	-147
150	Koolau	125	124	125	83	125	44	125	5	125	-33	125	-66	316	-90	203	-108	203	-125
170	Pukele	125	94	125	64	125	35	125	6	125	-22	125	-48	125	-73	316	-90	203	-105

Table O-24. Summary of Results 2020 QV Analysis

Table O-24 shows the unit commitment and dispatch with Honolulu 8 and 9 synchronous condensers meets the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Analysis was performed on two hours from the Theme 5 production simulation data that represent a typical and a boundary condition.

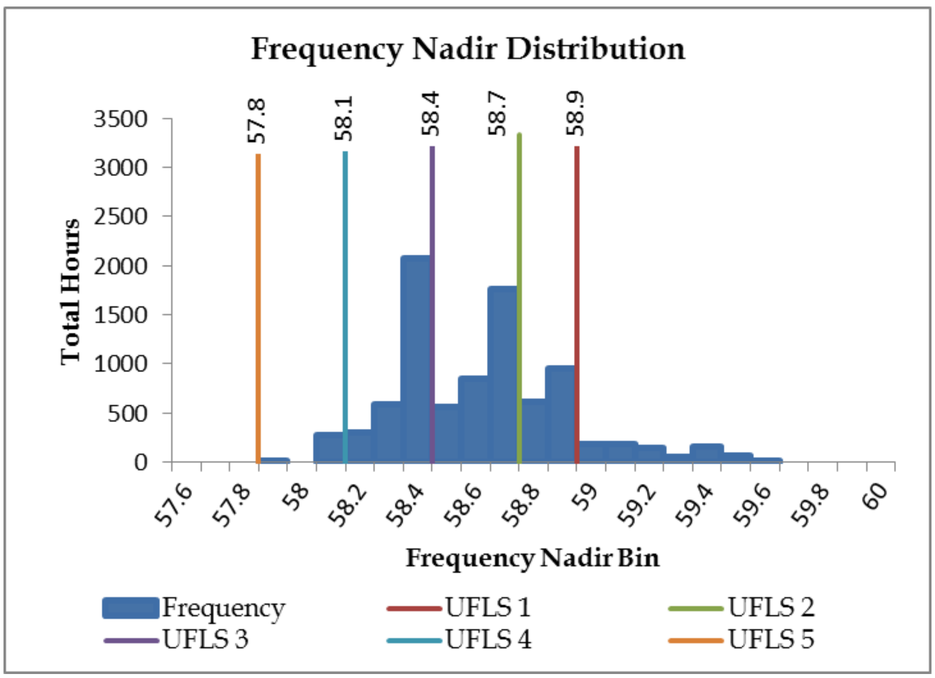

Figure O-36. Frequency Nadir Histogram 2020

Figure O-36 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 2076 hours was 4:00 PM on Monday, August 17. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 271 hours was 10:00 AM on Thursday, December 24. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

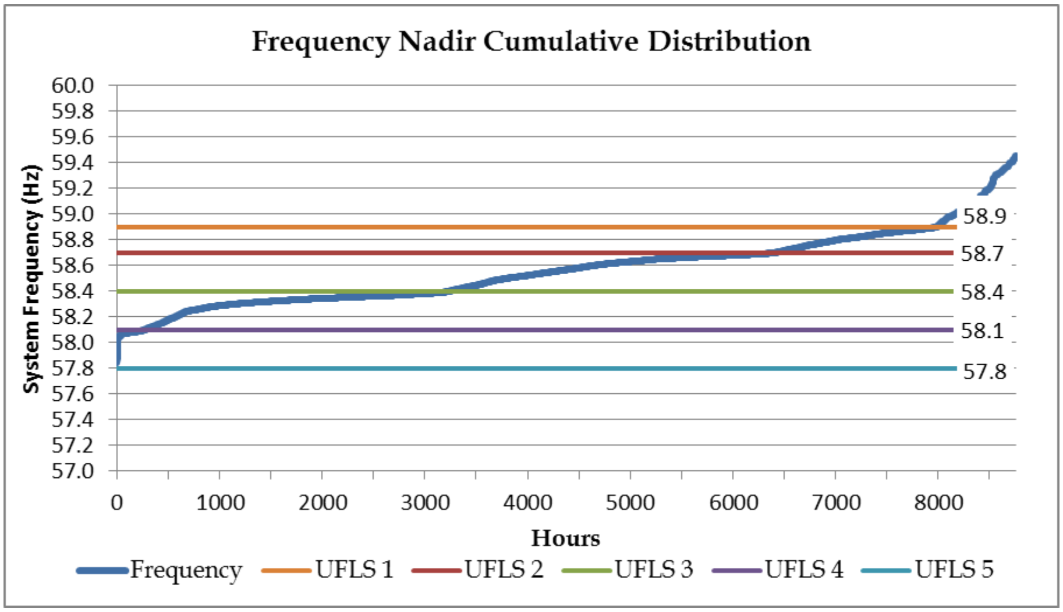

Figure O-37. Frequency Nadir Duration Curve 2020

Figure O-37 shows the frequency nadir duration curve for 2020. The system is at risk of UFLS for 7960 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Mon 8/17/20 Hour 16			Theme 5 - AES Trip Boundary Thu 12/24/20 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kalaeloa ST	40.0	10.0			4.70	61.1	287	28.8	11.2	18.8	22.0	18.0	12.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	26.5	55.7	2.7			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	21.0	113.6	0.0	21.0	113.6	0.0
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						53			16		
-Kahuku	30	0						9			1		
-Kawailoa	69	0						20			7		
-Na Pua Makani	24	0						16			0		
-CBRE Wind	10	0						2			2		
DG-PV	749	0						411			206		
Station PV	363	0						288			214		
Total Kinetic Energy								4161			3378		
Total Load								1226			824		
Total Thermal Generation								474			387		
Total Renewable Generation								752			436		
Total Generation								1226			824		
Excess Generation								0			0		
Total Up Regulation								293			213		
Total Down Regulation								240			200		
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		40.3	59.3Hz Output		20.3
	60.5Hz Capacity			215.9				60.5Hz Output		118.4	60.5Hz Output		59.5

Table O-25. Unit Commitment and Dispatch 2020

Table O-25 shows the unit commitment and dispatch for the typical hour (8/17/20, 4:00 PM) and boundary hour (12/24/20, 10:00 AM).

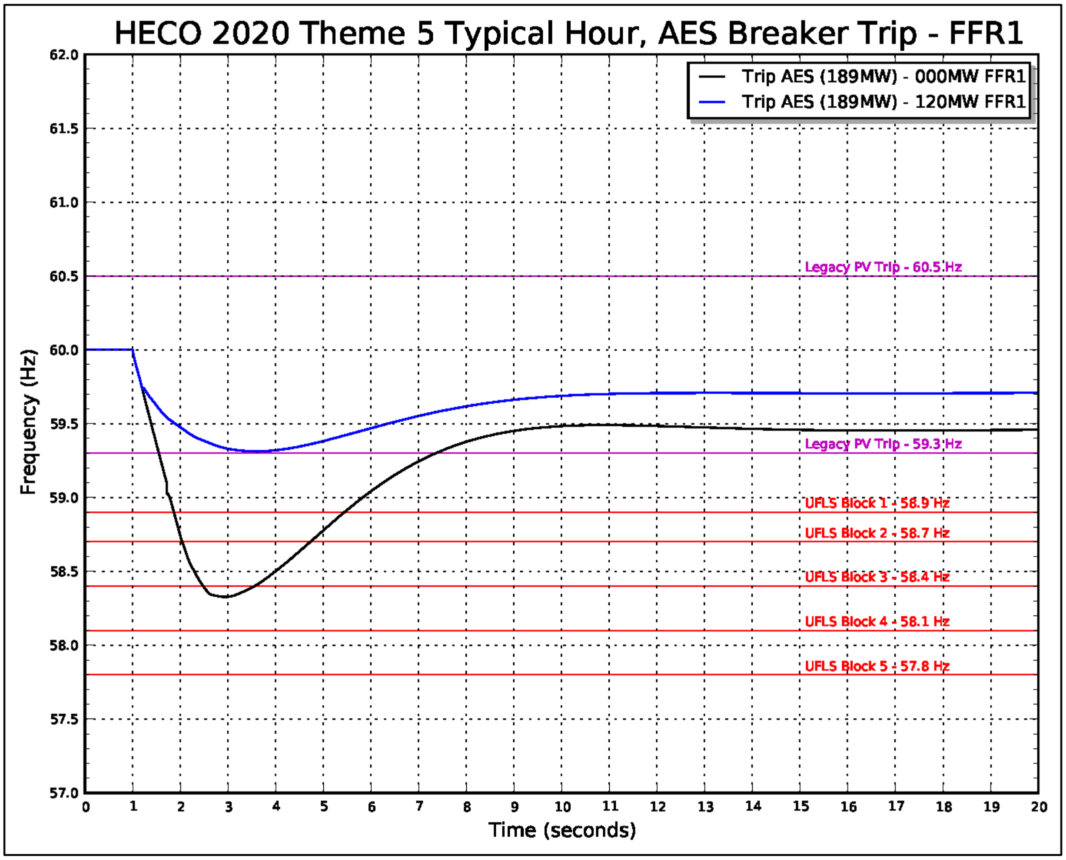

Figure O-38. Frequency Response Profile FFR1 Typical Hour

Figure O-38 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 4161 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.3 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

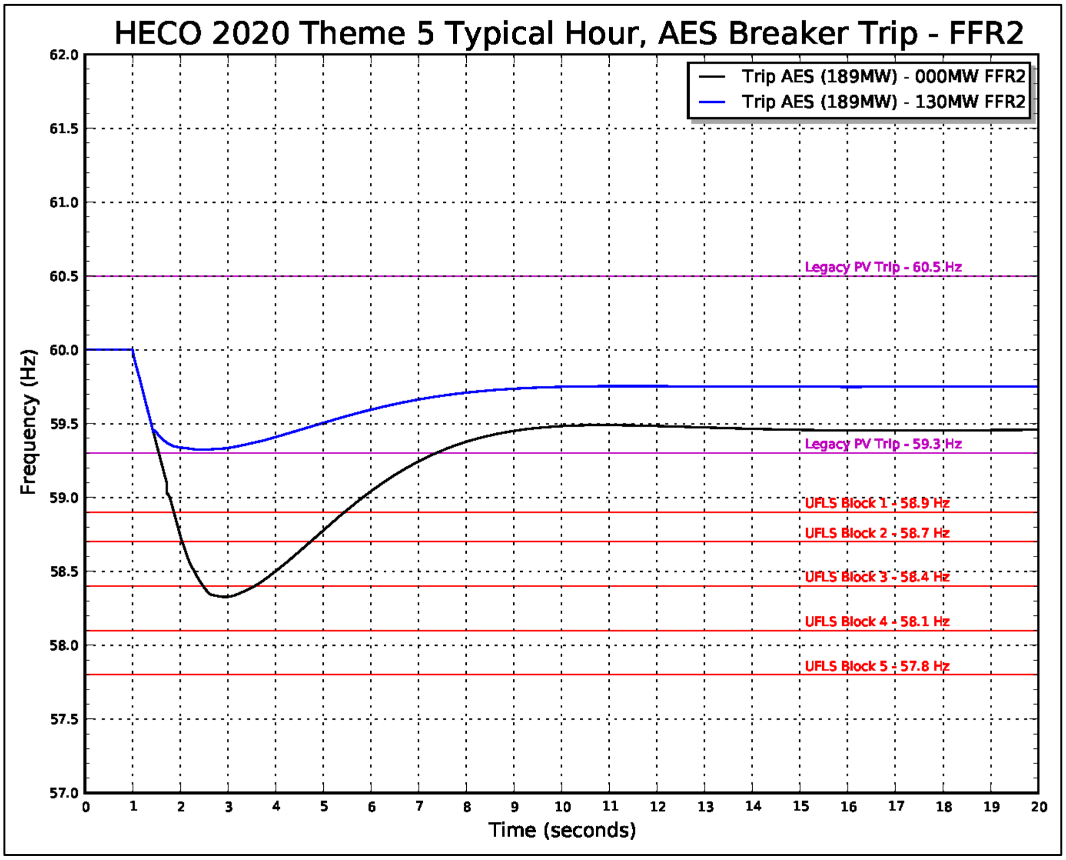

Figure O-39. Frequency Response Profile FFR2 Typical Hour

Figure O-39shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

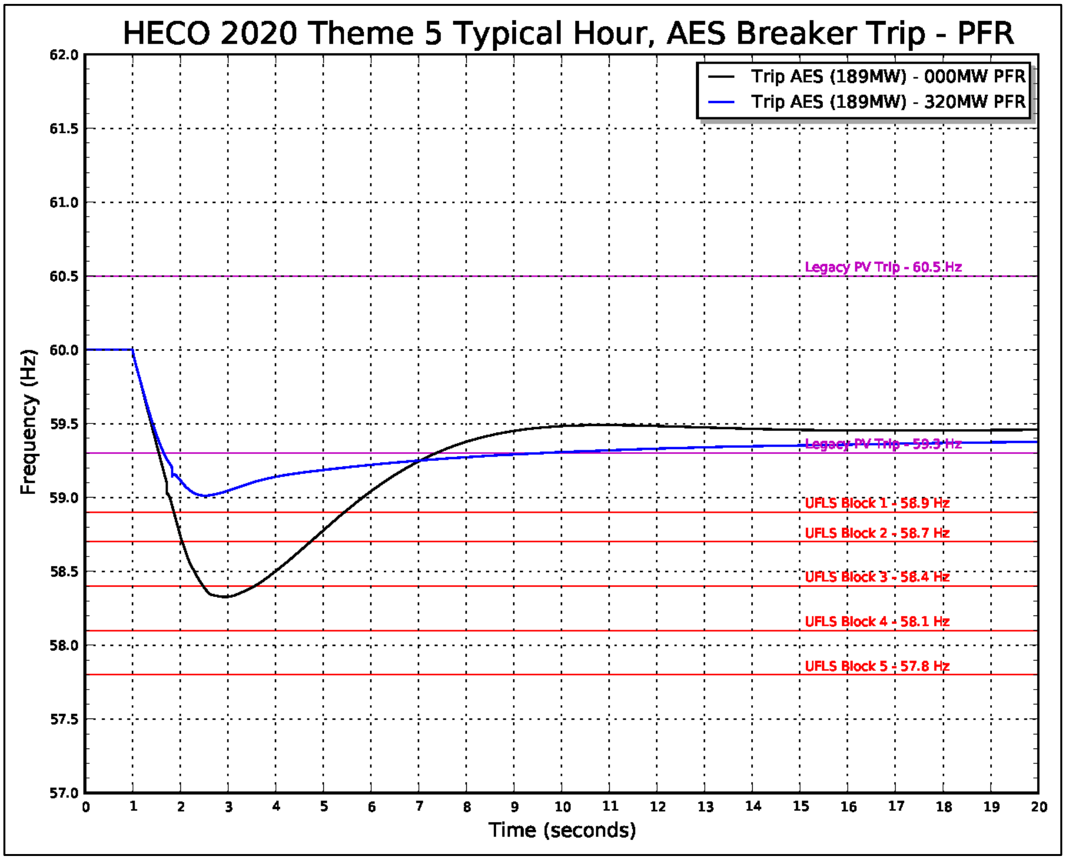

Figure O-40. Frequency Response Profile PFR Typical Hour

Figure O-40 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 320 MW. This is in addition to the 293 MW of upward regulation from thermal generation.

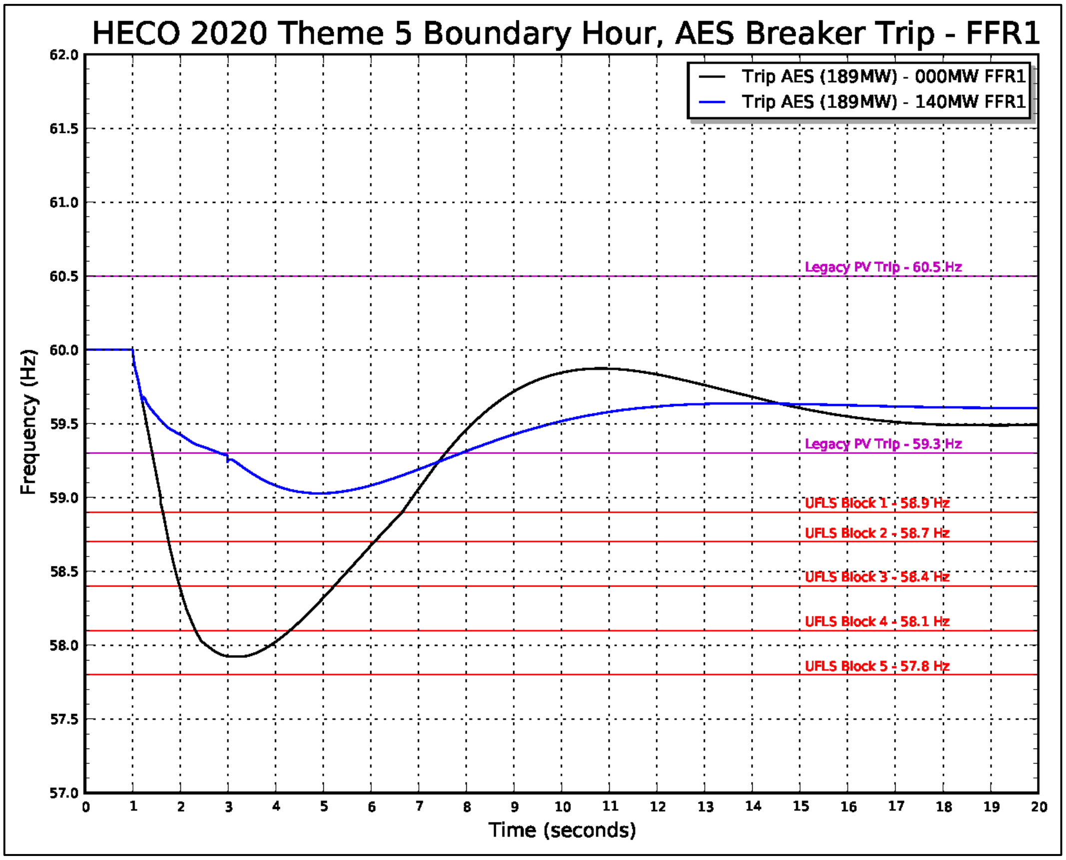

Figure O-41. Frequency Response Profile FFR1 Boundary Hour

Figure O-41 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 20.3 MW. With no FFR, the frequency nadir is 57.9 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

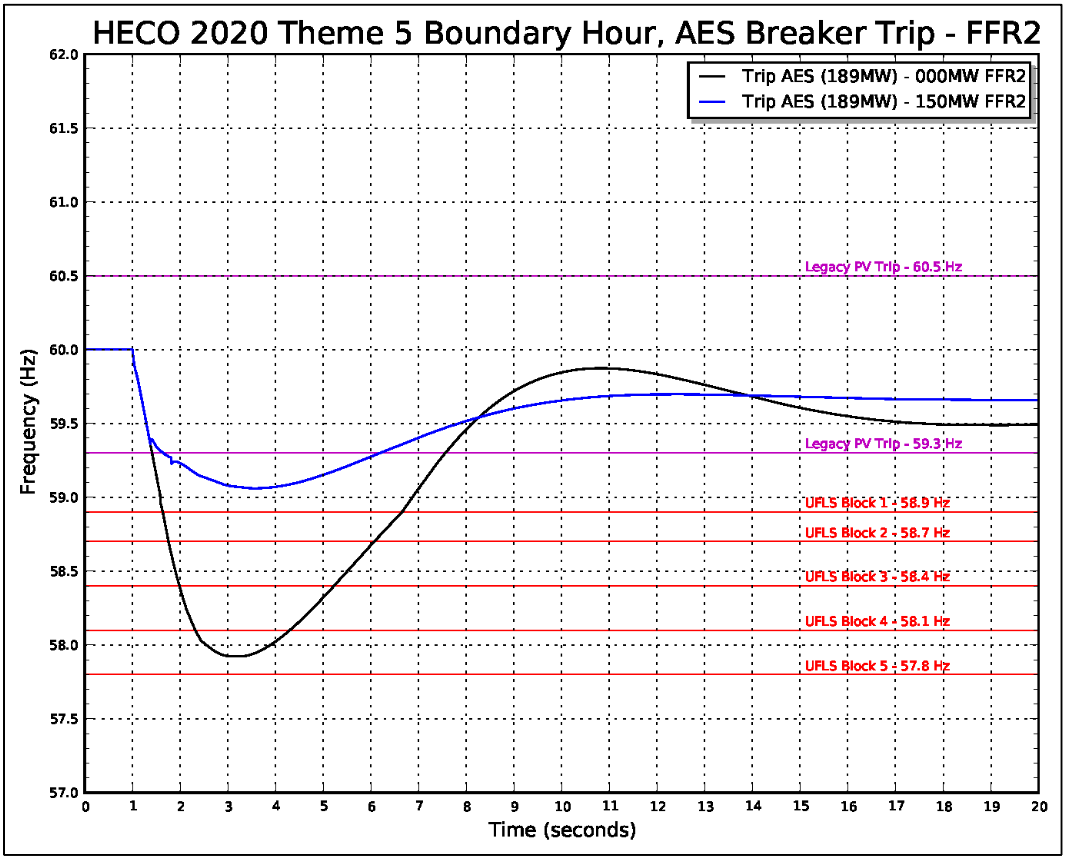

Figure O-42. Frequency Response Profile FFR2 Boundary Hour

Figure O-42 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

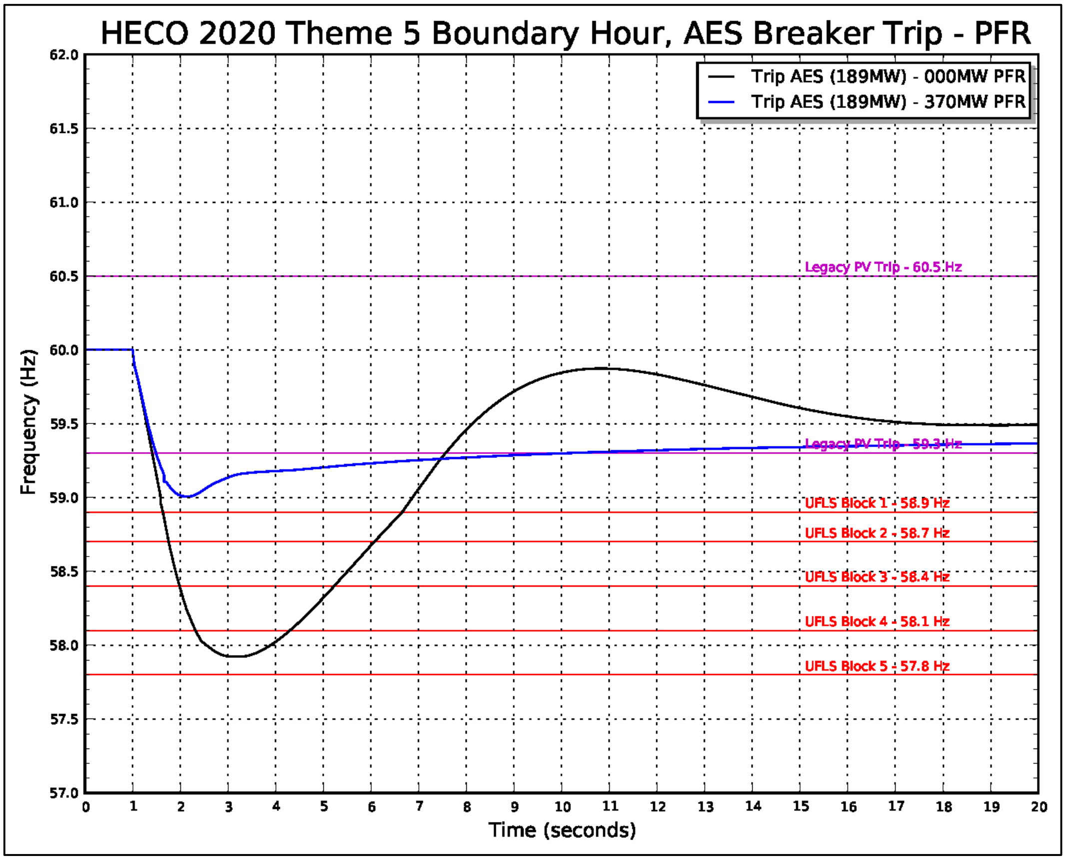

Figure O-43. Frequency Response Profile PFR Boundary Hour

Figure O-43 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 370 MW. This is in addition to the 213 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Mon 8/17/20 Hour 16			Theme 5 - K5 Trip Boundary Thu 12/24/20 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	75.0	114.0	12.0	75.0	114.0	12.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kalaeloa ST	40.0	10.0			4.70	61.1	287	28.8	11.2	18.8	22.0	18.0	12.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	60.5	23.5	31.5	46.2	37.8	17.2
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	26.5	55.7	2.7			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						53			16		
-Kahuku	30	0						9			1		
-Kawailoa	69	0						20			7		
-Na Pua Makani	24	0						16			0		
-CBRE Wind	10	0						2			2		
DG-PV	749	0						411			206		
Station PV	363	0						288			214		
Total Kinetic Energy								4161			3378		
Total Load								1226			824		
Total Thermal Generation								474			387		
Total Renewable Generation								752			436		
Total Generation								1226			823		
Excess Generation								0			0		
Total Up Regulation								294			213		
Total Down Regulation								240			200		
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		40.3	59.3Hz Output		20.3
	60.5Hz Capacity		215.9					60.5Hz Output		118.4	60.5Hz Output		59.5

Table O-26. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-26 shows the unit commitment and dispatch for the typical hour (8/17/20, 4:00 PM) and boundary hour (12/24/20, 10:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

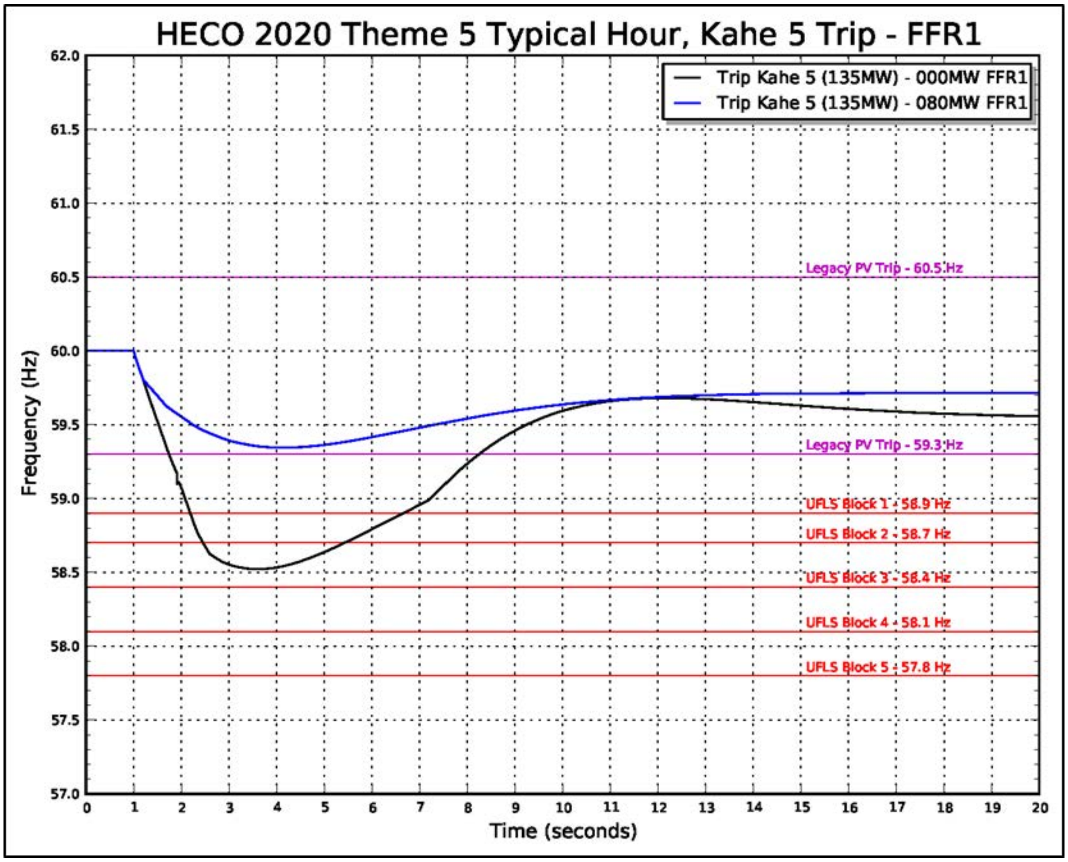

Figure O-44. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-44 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4161 MW-sec and the capacity of legacy PV that will disconnect from the system is 40.3 MW. With no FFR, the frequency nadir approaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 80 MW.

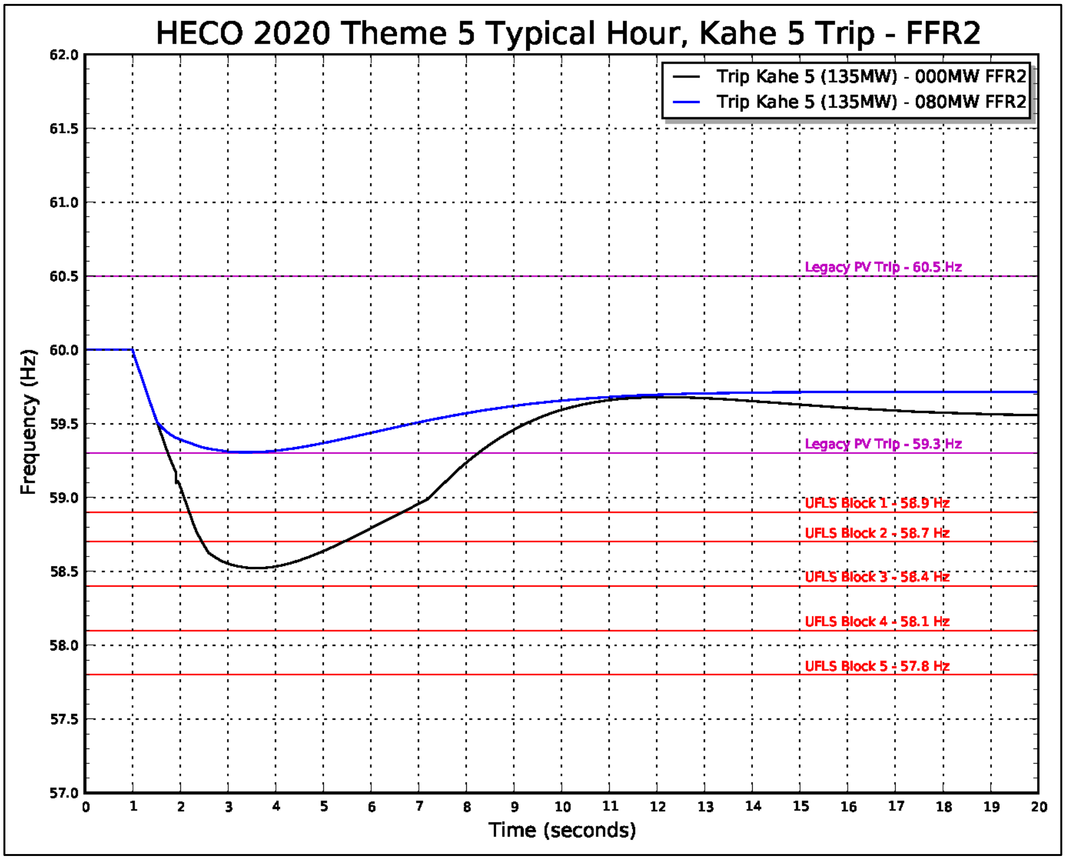

Figure O-45. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-45 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 80 MW.

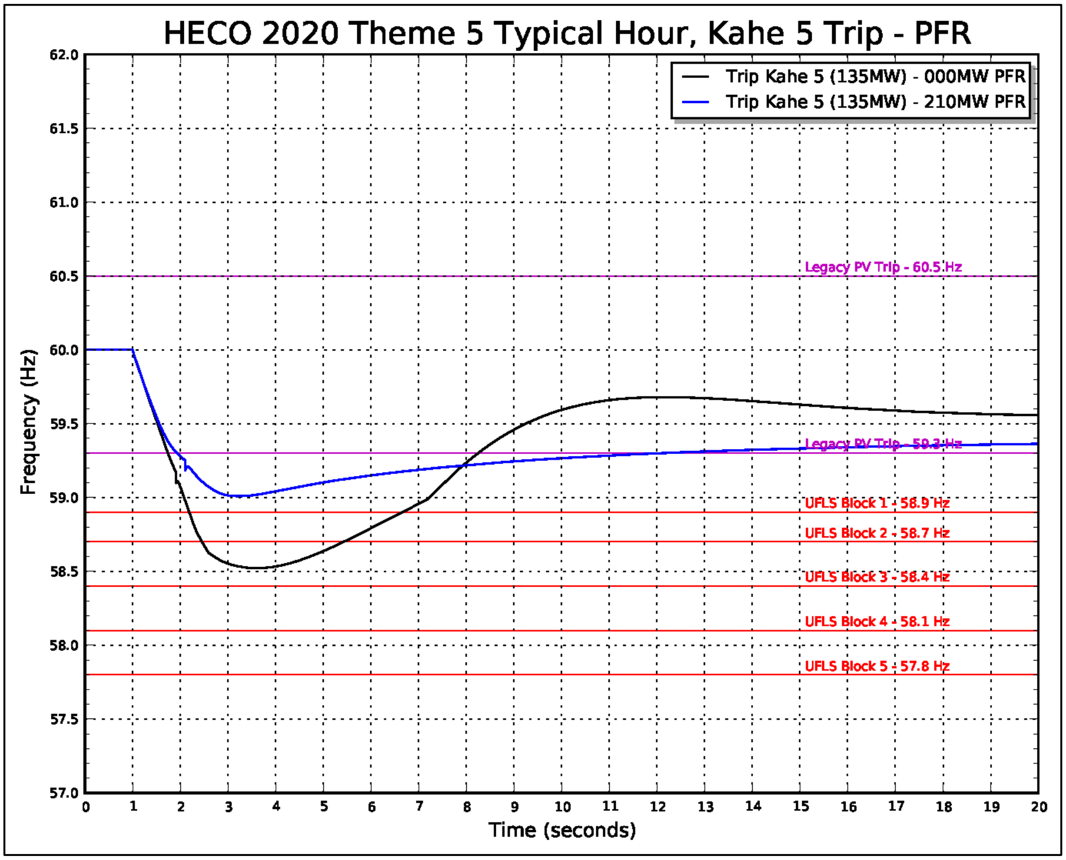

Figure O-46. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-46 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 210 MW. This is in addition to the 294 MW of upward regulation from thermal generation.

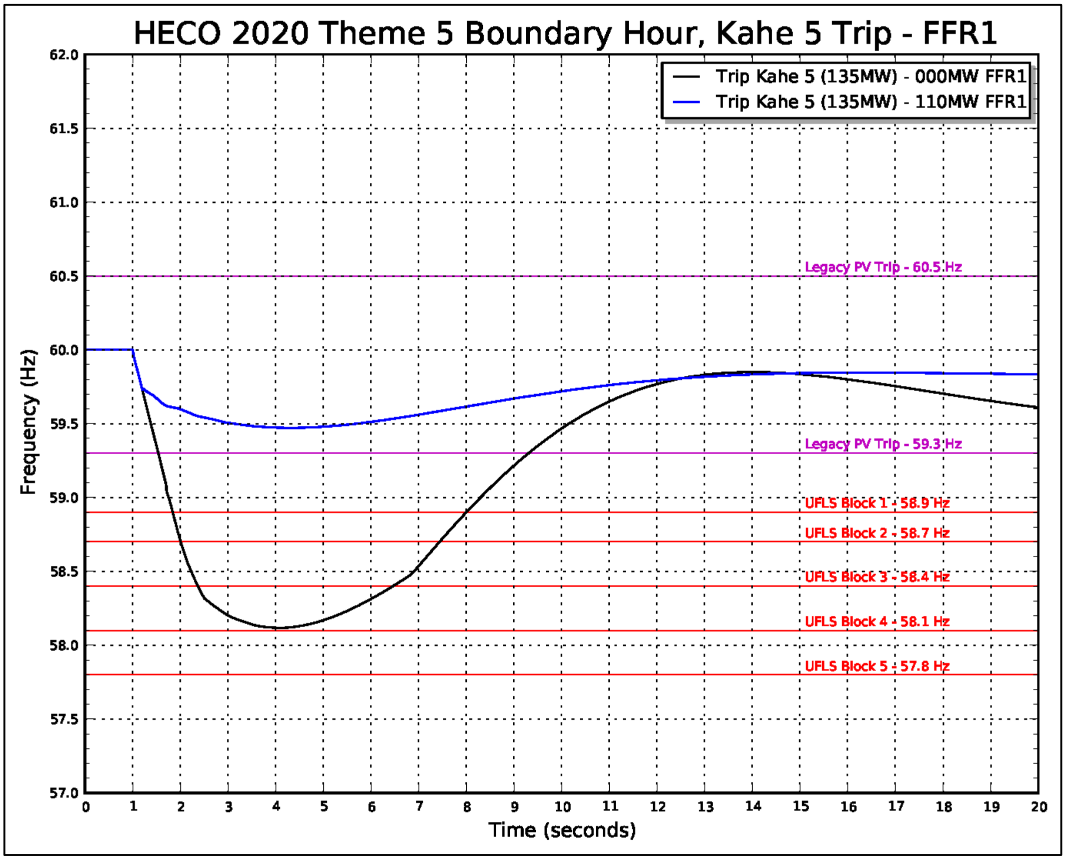

Figure O-47. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-47 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 20.3 MW. With no FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW.

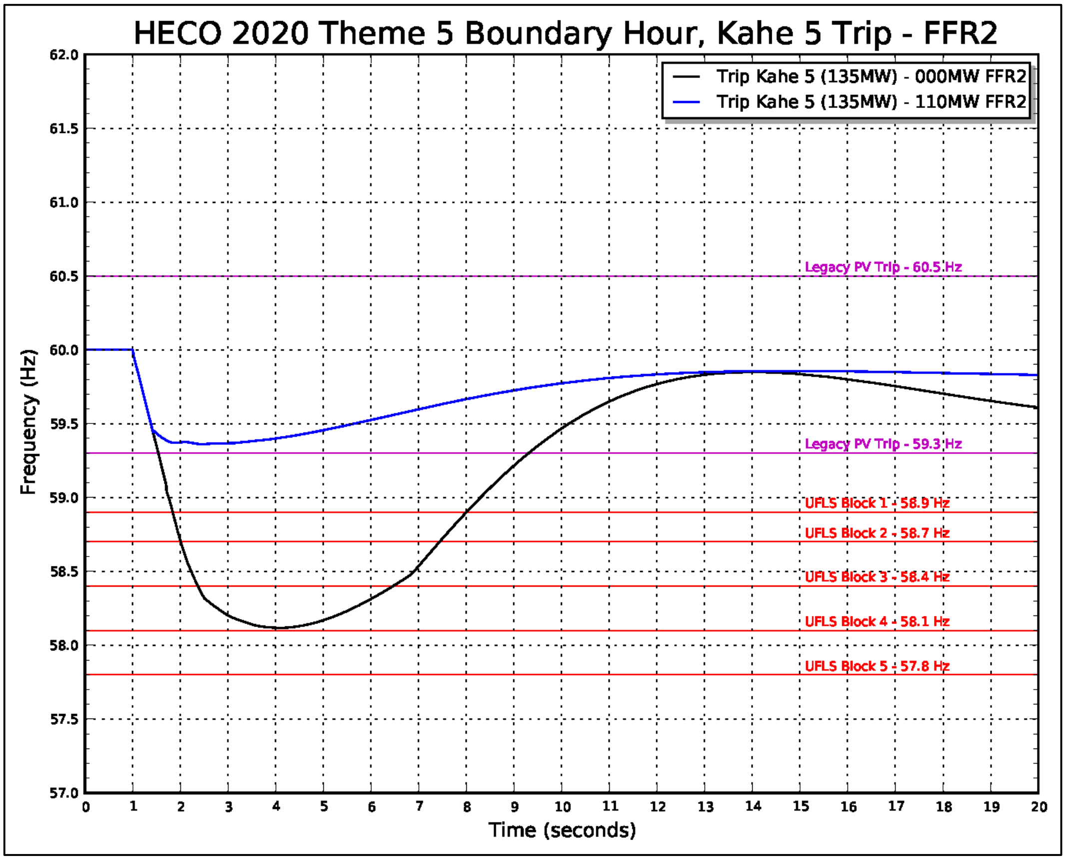

Figure O-48. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-48 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 110 MW.

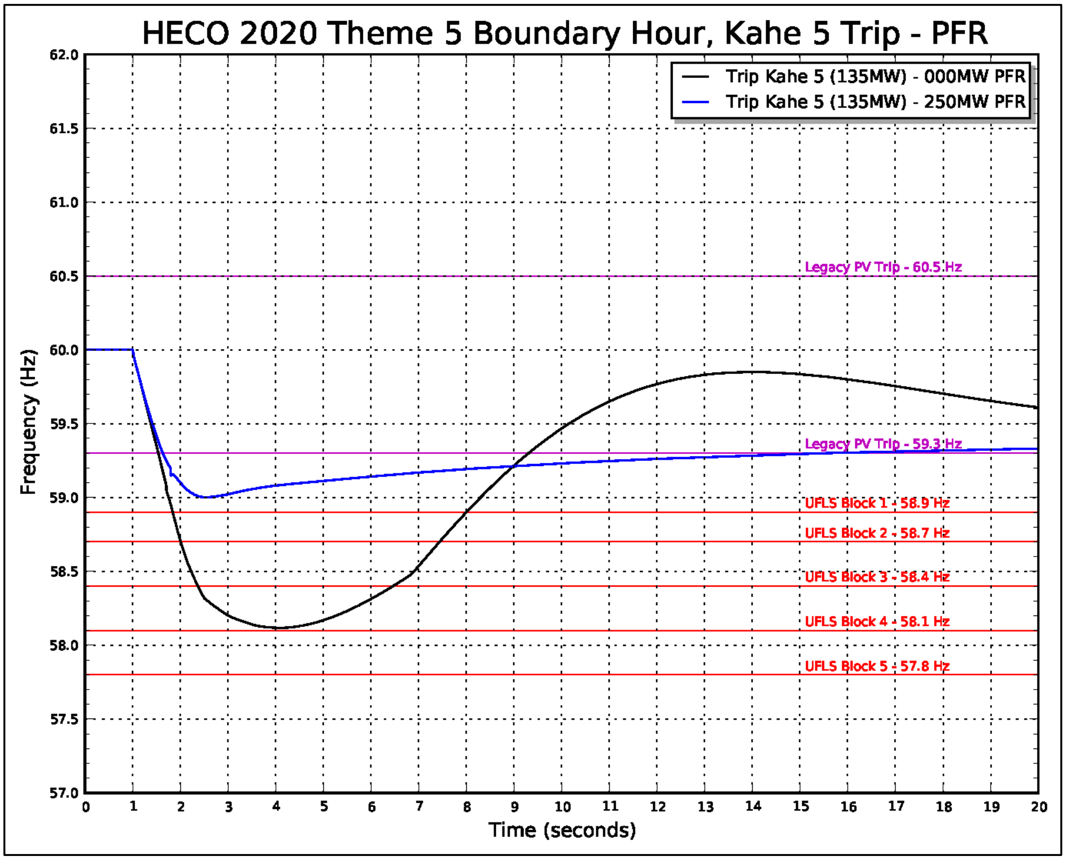

Figure O-49. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-49 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 250 MW. This is in addition to the 213 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							Theme 5 - Fault Sun 6/7/20 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	50.9	33.1	21.9
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.1	27.9	2.1
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357			
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163	0						66		
-Kahuku	30	0						17		
-Kawailoa	69	0						25		
-Na Pua Makani	24	0						15		
-CBRE Wind	10	0						0		
DG-PV	693	0						549		
Station PV	367	0						186		
Total Kinetic Energy									2094	
Total Load									989	
Total Thermal Generation									189	
Total Renewable Generation									800	
Total Generation									989	
Excess Generation									0	
Total Up Regulation									192	
Total Down Regulation									52	
Legacy DG-PV		59.3Hz Capacity		73.5				59.3Hz Output		58.8
		60.5Hz Capacity		215.9				60.5Hz Output		172.7

Table O-27. Unit Commitment and Dispatch Fault Analysis

Table O-27 shows the unit commitment and dispatch for the fault analysis.

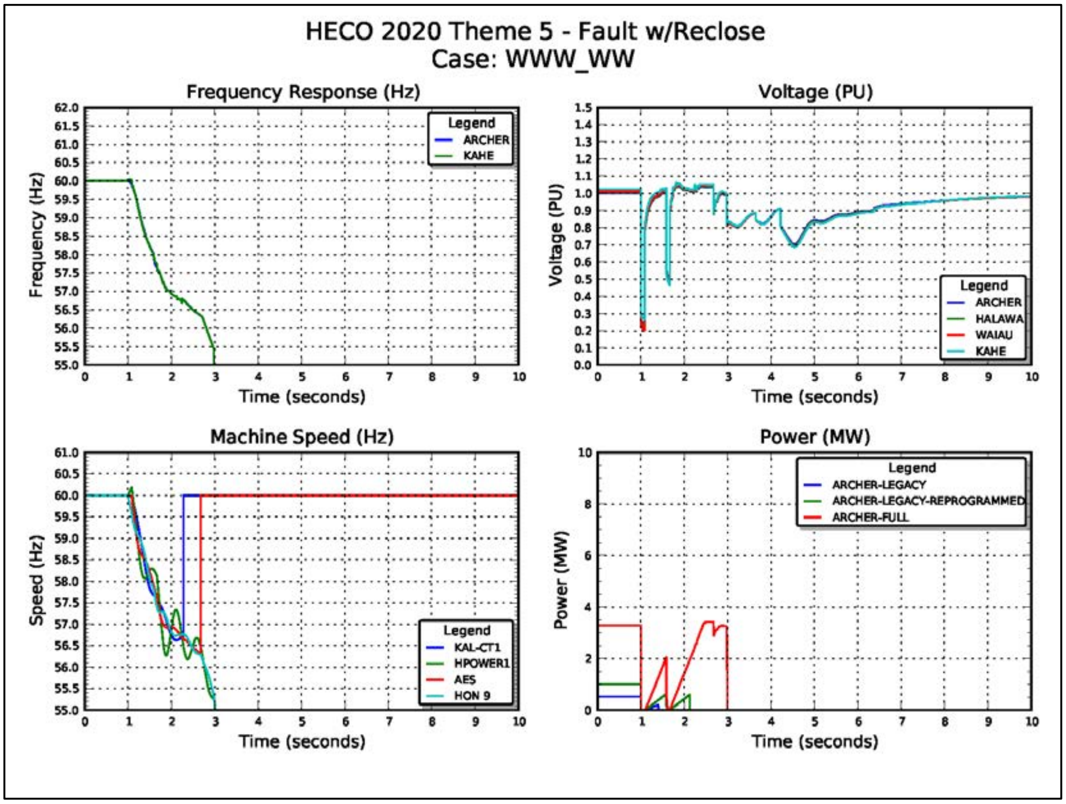

Figure O-50. System Performance for Normally Cleared Fault

Figure O-50 shows the system performance for a normally cleared fault on the Waiau-Wahiawa circuit, which is the only simulation that resulted in system collapse. System voltage is suppressed below the 0.5 PU threshold where the 735 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz. The remaining synchronous units trip on under frequency protection, causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize the system.

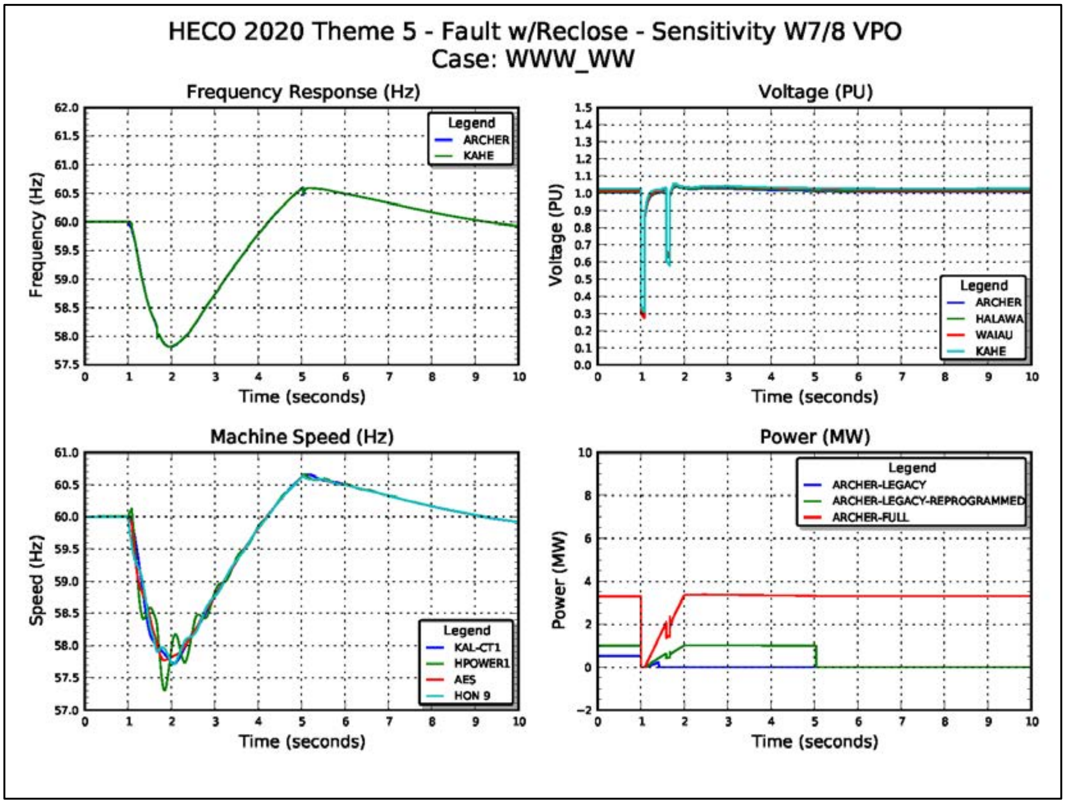

Figure O-51. Normally Cleared Fault Sensitivity Analysis VPO Units

Figure O-51 shows system performance with Waiau Units 7 and 8 operating in VPO. The VPO units add inertia, MVAR/voltage support at the load center, and increases the magnetic strength of the system. With the thermal units remaining online, system voltage recovers and most of the DG-PV generation is restored. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 57.8 Hz.

The system does not meet the requirements of TPL-001. Non-exhaustive sensitivity analyses were performed to bring the system into compliance with TPL-001.

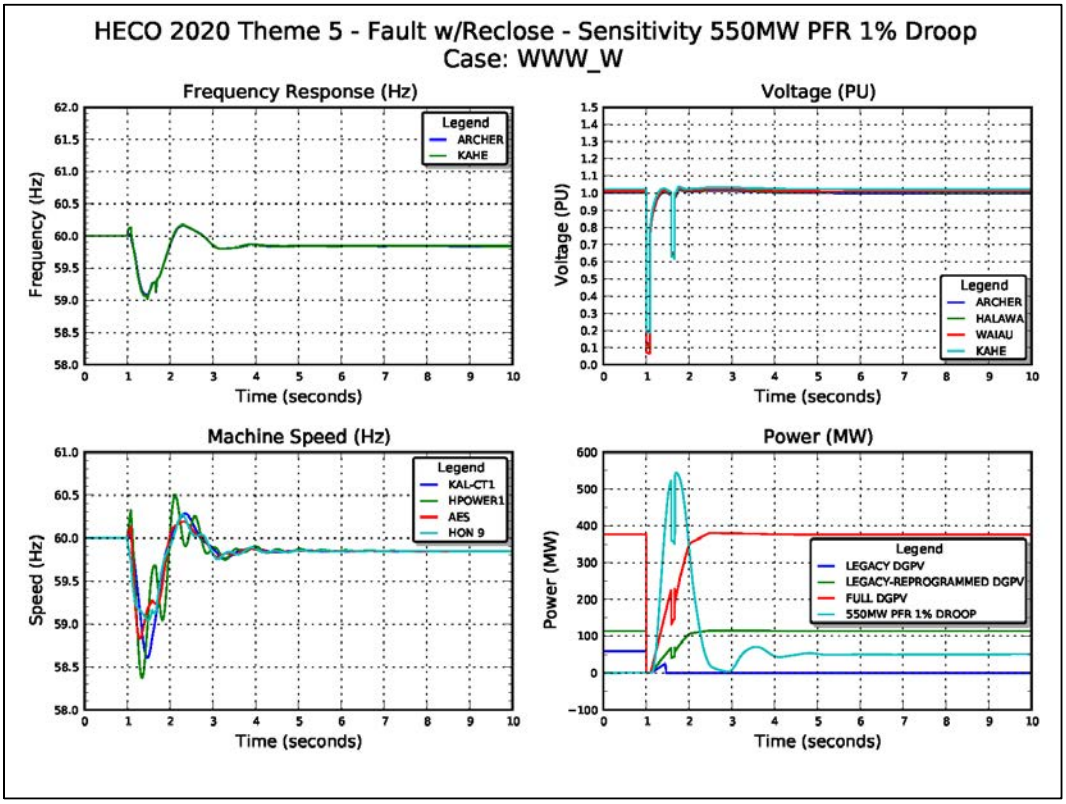

Figure O-52. Normally Cleared Fault Sensitivity Analysis 550 PFR

Figure O-52 shows system performance with the addition of the 550 MW of PFR at 1% droop response. For the purpose of this analysis, a 550 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, 550 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

2020 138 kV Fault Analysis				
Circuit Outage	Reclose TD	System Status	Waiau 7/8 VPO Mitigation	550 MW PFR Mitigation
CEIP-Ewa Nui	30	Stable	Stable	Stable
Halawa-Iwilei	30	Stable	Stable	Stable
Halawa-Koolau	30	Stable	Stable	Stable
Halawa-School	30	Stable	Stable	Stable
Kahe-CEIP 1	30	Stable	Stable	Stable
Kahe-CEIP 2	30	Stable	Stable	Stable
Kalaeloa-Ewa Nui	30	Stable	Stable	Stable
Kahe-Halawa 1	30	Stable	Stable	Stable
Kahe-Halawa 2	30	Stable	Stable	Stable
Kahe-Waiau	30	Stable	Stable	Stable
Makalapa-Airport	30	Stable	Stable	Stable
Waiau-Ewa Nui 1	30	Stable	Stable	Stable
Waiau-Ewa Nui 2	30	Stable	Stable	Stable
Waiau-Koolau 1	30	Stable	Stable	Stable
Waiau-Koolau 2	30	Stable	Stable	Stable
Waiau-Makalapa 1	30	Stable	Stable	Stable
Waiau-Makalapa 2	30	Stable	Stable	Stable
Waiau-Wahiawa	30	Unstable	Stable	Stable

Table O-28. Summary of Results Normal Clearing Fault Analysis

Table O-28 shows the results of the normal clearing fault analysis. A fault on the Waiau-Wahiawa circuit resulted in system instability where system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to disconnect from the system. Committing Waiau Units 7 and 8 in VPO can help stabilize system frequency for this contingency event but multiple blocks of UFLS was also required to stabilize system frequency.

The system requires 550 MW of PFR at 1% droop response to meet TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O'ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko'olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							Theme 5 - QV Dispatch Mon 7/19/21 Hour 17		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	13.0	VPO	VPO
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	40.0	42.2	16.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	42.0	44.2	18.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	53.0	32.3	29.4
Kahe 5	134.6	21.0			4.36	158.8	692	99.0	35.6	78.0
Kahe 6	133.8	40.0			4.36	158.8	692	71.0	62.8	31.0
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163.0	0.0						62.0		
-Kahuku	30.0	0.0						21.0		
-Kawailoa	69.0	0.0						30.0		
-Na Pua Makani	24.0	0.0						3.0		
-CBRE Wind	10.0	0.0						2.0		
-Future Wind	30.0	0.0						6.0		
-Offshore Wind	0.0	0.0								
Total Station PV	462.2	0.0						197.0		
-KS2	5.0	0.0						1.0		
-KREP	5.0	0.0						3.0		
-Waianae	27.6	0.0						15.0		
-Kawailoa PV	49.0	0.0						35.0		
-Mililani 2	14.7	0.0						9.0		
-Waiawa	45.9	0.0						30.0		
-Westloch	20.0	0.0						9.0		
-CBRE PV	15.0	0.0						5.0		
-Future PV	280.0	0.0						90.0		
DG-PV	791.0	0.0						222.0		
Total Kinetic Energy									5637	
Total Load									1241	
Total Thermal Generation									760	
Total Renewable Generation									481	
Total Generation									1241	
Excess Generation									0	
Total Up Regulation									241	
Total Down Regulation									449	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		20.6
	60.5Hz Capacity			215.9				60.5Hz Output		60.6

Table O-29. Unit Commitment and Dispatch 2021 QV Analysis

Table O-29 shows the unit commitment and dispatch for the 2021 QV analysis.

Unit	Unit Ratings		Theme 5 - QV Dispatch Mon 7/19/21 Hour 17		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	5.4	30.6	-5.4
HPOWER-2	28.0	-16.0	5.4	22.6	-21.4
AES	99.4	-49.8	32.4	67.0	-82.2
Kalaeloa CT-1	84.5	-35.9	19.6	64.9	-55.5
Kalaeloa ST	84.5	-35.8	19.6	64.9	-55.4
Kalaeloa CT-2	42.1	-16.7	19.6	22.5	-36.3
Kahe 1	70.2	-52.0	19.6	50.6	-71.6
Kahe 2	64.4	-50.3	19.6	44.8	-69.9
Kahe 3	69.7	-19.7	19.6	50.1	-39.3
Kahe 4	61.5	-16.8	19.6	41.9	-36.4
Kahe 5	95.6	-62.9	94.5	1.1	-157.5
Kahe 6	106.6	-61.3	38.6	68.0	-99.9
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	25.1	25.9	-58.1
Hon 9 (Sync Cond)	51.0	-33.0	25.1	25.9	-58.1
Total Wind	96.7	-120.3	14.9	81.9	-135.2
-Kahuku	17.9	-17.9	6.2	11.7	-24.0
-Kawailoa	50.0	-74.5	8.6	41.4	-83.1
-Na Pua Makani	16.4	-15.4	0.1	16.3	-15.5
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.4	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	234.4	-234.4	20.8	213.6	-255.2
-KS2	1.6	-1.6	1.3	0.3	-2.9
-KREP	2.0	-2.0	2.0	0.0	-4.0
-Waianae	14.5	-14.5	2.5	12.0	-17.0
-Kawailoa PV	36.8	-36.8	-0.5	37.3	-36.2
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.4
-Waiawa	32.9	-32.9	1.3	31.6	-34.2
-Westloch	6.3	-6.3	3.2	3.0	-9.5
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	125.0	-125.0	11.3	113.7	-136.3
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			363.6		
Total Renewable MVAR Generation			35.7		
Total Cap Bank MVAR			184.7		
Charging MVAR			76.7		
Total MVAR Supply			660.6		
Total MVAR Load			402.8		
Total MVAR Losses			257.8		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				876.5	
Total MVAR Absorb Capability					-1237.2

Table O-30. MVAR Capability 2021 QV Analysis

Table O-30 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-31. N-2 Contingencies 2021 QV Analysis

Table O-31 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

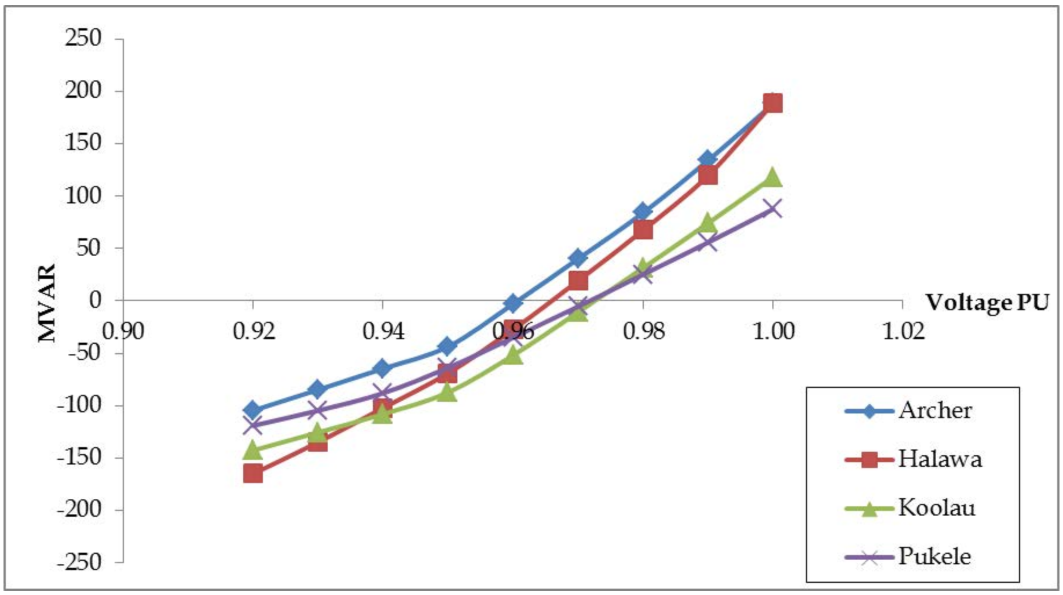

Figure O-53. QV Curves 2021

Figure O-53 shows the QV curves for the Archer, Halawa, Ko‘olau, and Pukele busses for the worst-case N-2 contingency event. The reactive power requirements are met with the additional MVARs from the Honolulu 8 and 9 synchronous condensers.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	188	125	134	154	84	154	40	154	-3	135	-44	135	-65	135	-85	135	-105
120	Halawa	125	189	125	120	154	68	154	19	154	-27	154	-69	154	-102	154	-135	154	-165
150	Koolau	125	118	125	74	125	32	125	-11	125	-52	316	-87	316	-108	203	-126	203	-143
170	Pukele	125	88	125	56	125	25	125	-5	125	-35	125	-64	316	-88	316	-105	203	-119

Table O-32. Summary of Results 2021 QV Analysis

Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

Table O-32 shows the results of the 2021 QV analysis. The unit commitment and dispatch with Honolulu 8 and 9 synchronous condensers meets the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

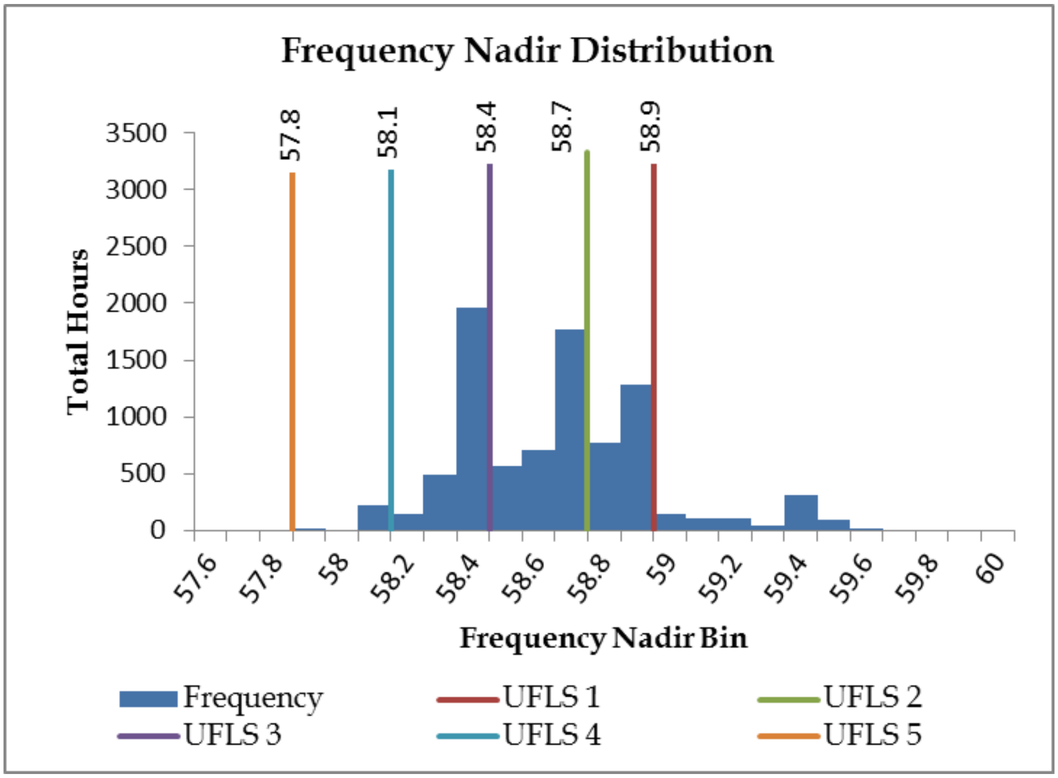

Figure O-54. Frequency Nadir Histogram 2021

Figure O-54 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 1964 hours was 3:00 PM on Wednesday, November 3. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 220 hours was 10:00 AM on Friday, August 6. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

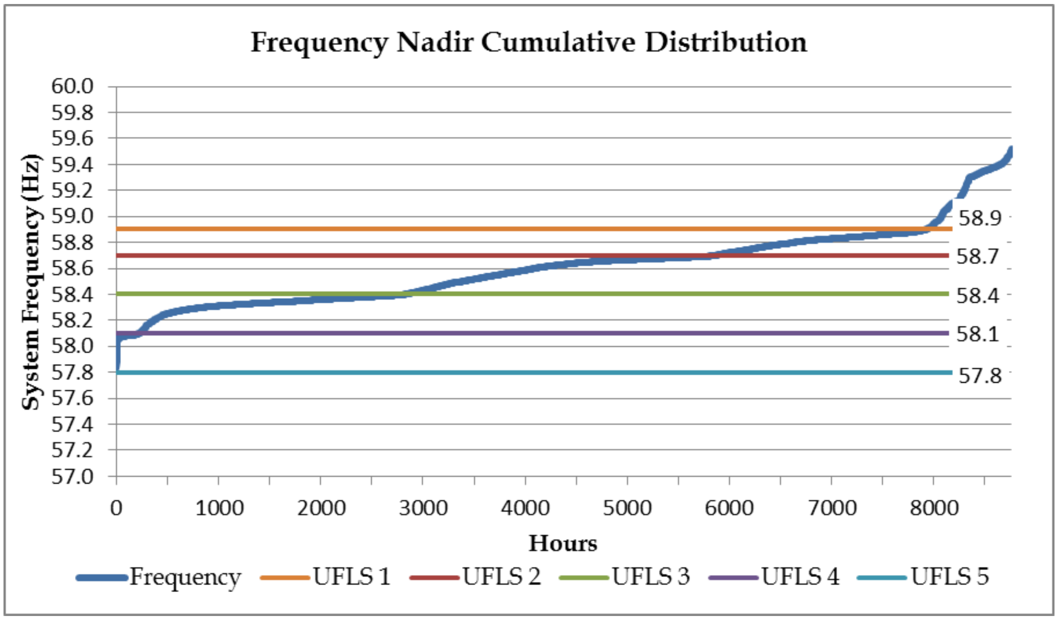

Figure O-55. Frequency Nadir Duration Curve 2021

Figure O-55 shows the frequency nadir duration curve for 2021. The system is at risk of UFLS for 7925 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Wed 11/3/21 Hour 15			Theme 5 - AES Trip Boundary Fri 8/6/21 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	41.5	4.5	16.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kalaeloa ST	40.0	10.0			4.70	61.1	287	27.6	12.4	17.6	32.3	7.7	22.3
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	26.4	108.2	5.4	21.4	113.2	0.4
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						33			41		
-Kahuku	30	0						5			14		
-Kawailoa	69	0						8			21		
-Na Pua Makani	24	0						12			2		
-CBRE Wind	10	0						2			1		
DG-PV	720	0						363			283		
Station PV	467	0						309			146		
Total Kinetic Energy									3735			3378	
Total Load									1152			917	
Total Thermal Generation									448			447	
Total Renewable Generation									704			470	
Total Generation									1152			917	
Excess Generation									0			0	
Total Up Regulation									238			153	
Total Down Regulation									237			260	
Legacy DG-PV	59.3Hz Capacity	73.5						59.3Hz Output		36.7	59.3Hz Output		29.4
	60.5Hz Capacity	215.9						60.5Hz Output		107.9	60.5Hz Output		86.4

Table O-33. Unit Commitment and Dispatch 2021

Table O-33 shows the unit commitment and dispatch for the typical hour 11/3/21, 3:00 PM) and boundary hour (8/6/21, 10:00 AM).

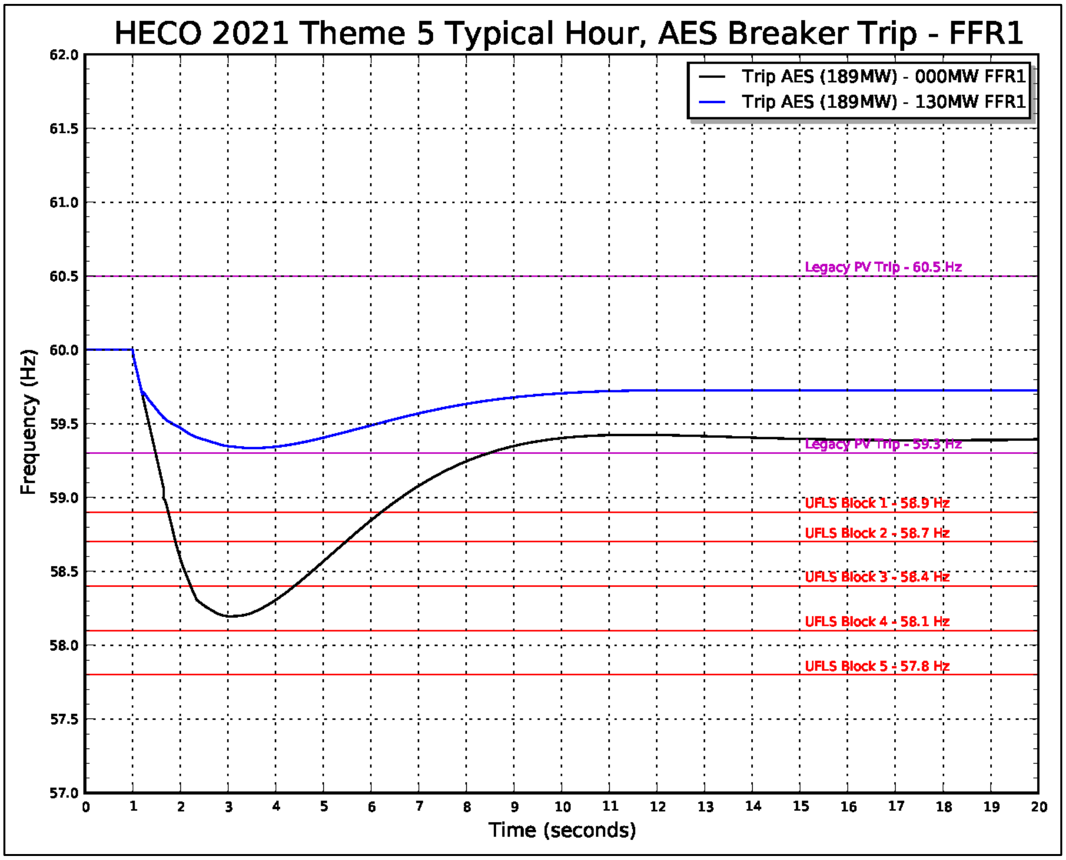

Figure O-56. Frequency Response Profile FFR1 Typical Hour

Figure O-56 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 36.7 MW. With no FFR, the frequency nadir is 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 130 MW.

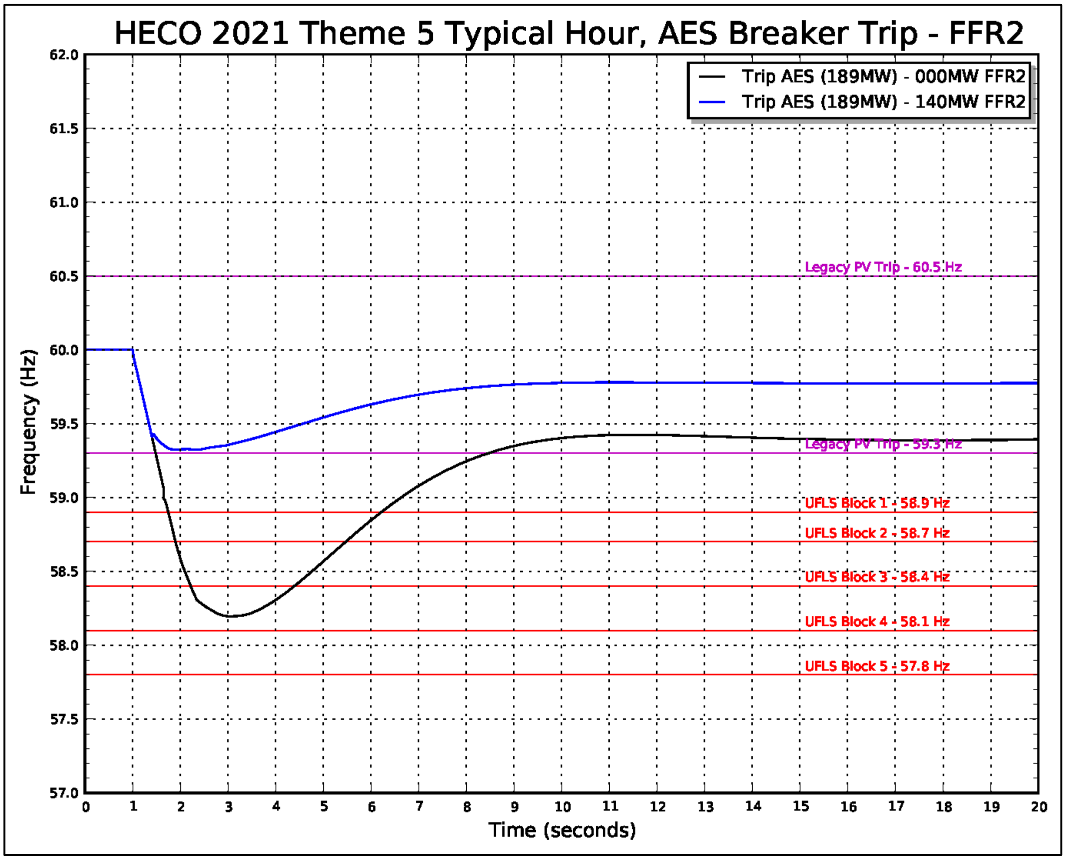

Figure O-57. Frequency Response Profile FFR2 Typical Hour

Figure O-57 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 140 MW.

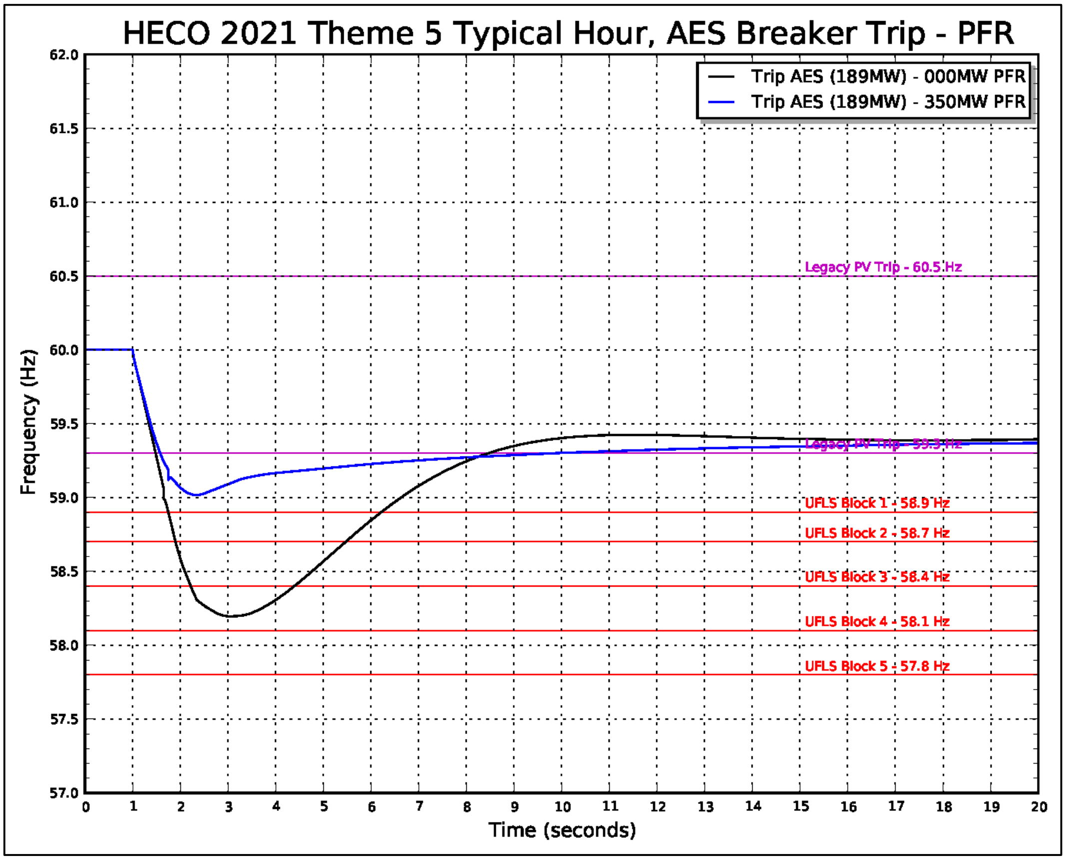

Figure O-58. Frequency Response Profile PFR Typical Hour

Figure O-58 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 350 MW. This is in addition to the 238 MW of upward regulation from thermal generation.

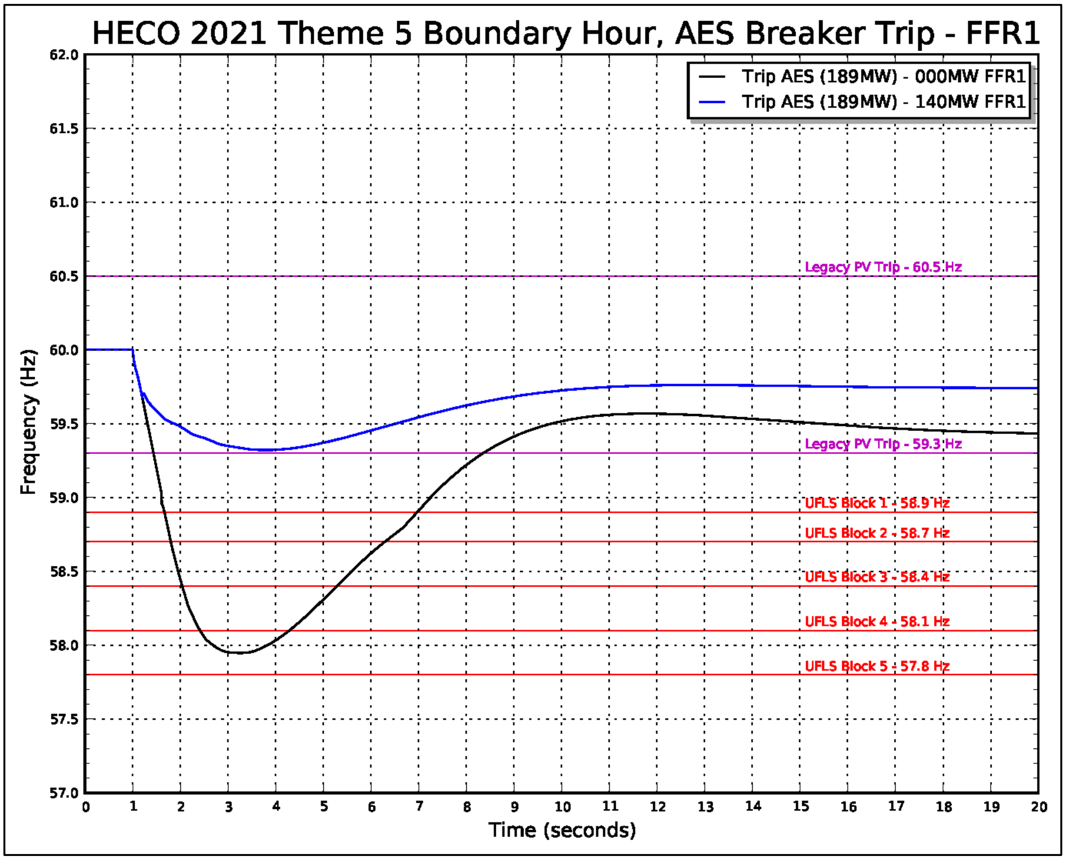

Figure O-59. Frequency Response Profile FFR1 Boundary Hour

Figure O-59 shows the frequency response profile for and AES trip at 189 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 57.9 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

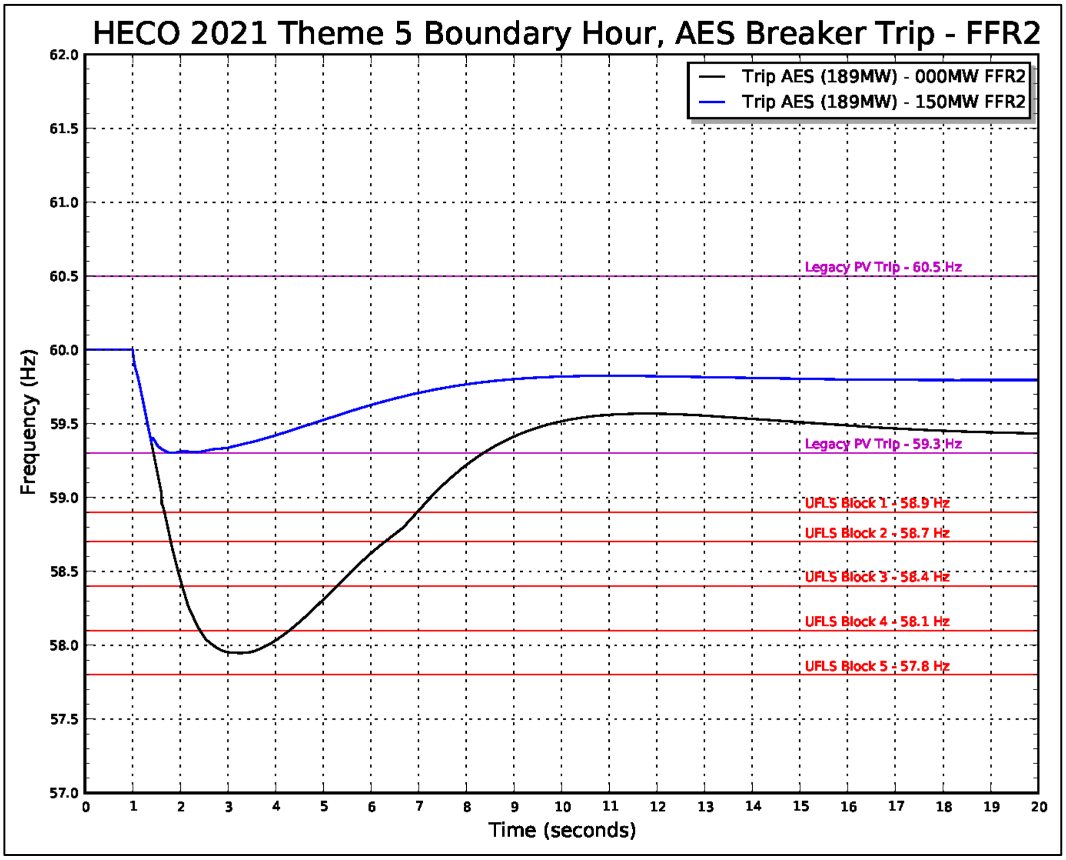

Figure O-60. Frequency Response Profile FFR2 Boundary Hour

Figure O-60 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

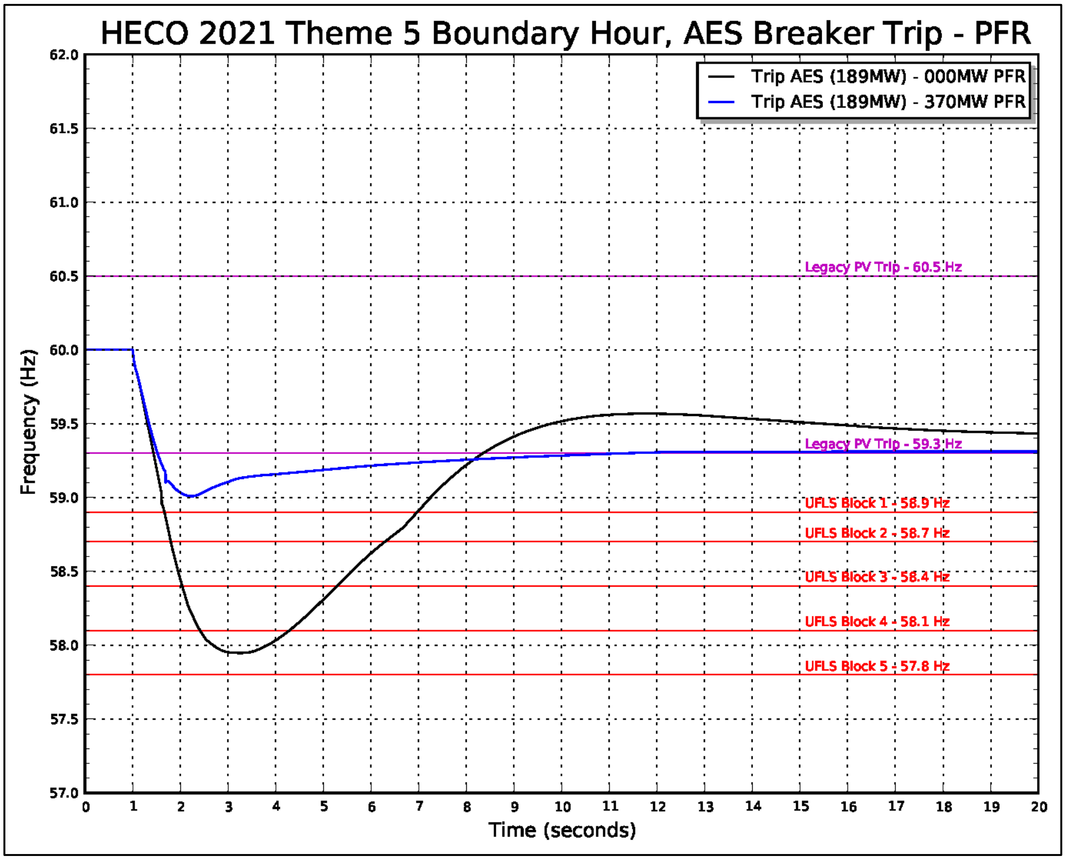

Figure O-61. Frequency Response Profile PFR Boundary Hour

Figure O-61 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 370 MW. This is in addition to the 153 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - Kahe 5 Trip Typical Wed 11/3/21 Hour 15			Theme 5 - K5 Trip Boundary Fri 8/6/21 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	41.5	4.5	16.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	81.0	108.0	18.0	76.0	113.0	13.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kalaeloa ST	40.0	10.0			4.70	61.1	287	27.6	12.4	17.6	32.3	7.7	22.3
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	58.0	26.0	29.0	67.9	16.1	38.9
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						33			41		
-Kahuku	30	0						5			14		
-Kawailoa	69	0						8			21		
-Na Pua Makani	24	0						12			2		
-CBRE Wind	10	0						2			1		
DG-PV	720	0						363			283		
Station PV	467	0						309			146		
Total Kinetic Energy									3735			3378	
Total Load									1152			917	
Total Thermal Generation									448			447	
Total Renewable Generation									704			470	
Total Generation									1152			918	
Excess Generation									0			0	
Total Up Regulation									238			153	
Total Down Regulation									237			260	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		36.7	59.3Hz Output		29.4
	60.5Hz Capacity		215.9					60.5Hz Output		107.9	60.5Hz Output		86.4

Table O-34. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-34 shows the unit commitment and dispatch for the typical hour (11/3/21, 3:00 PM) and boundary hour (8/6/21, 10:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

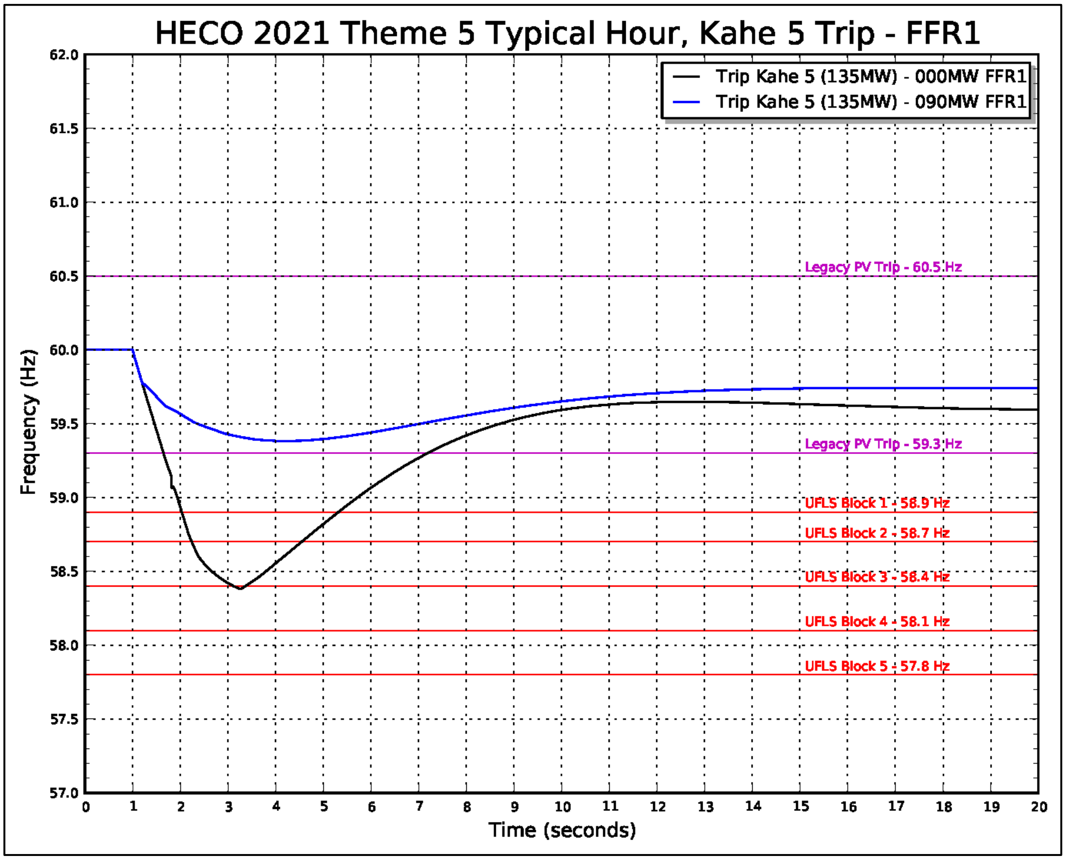

Figure O-62. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-62 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3735 MW-sec and the capacity of legacy PV that will disconnect from the system is 36.7 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW.

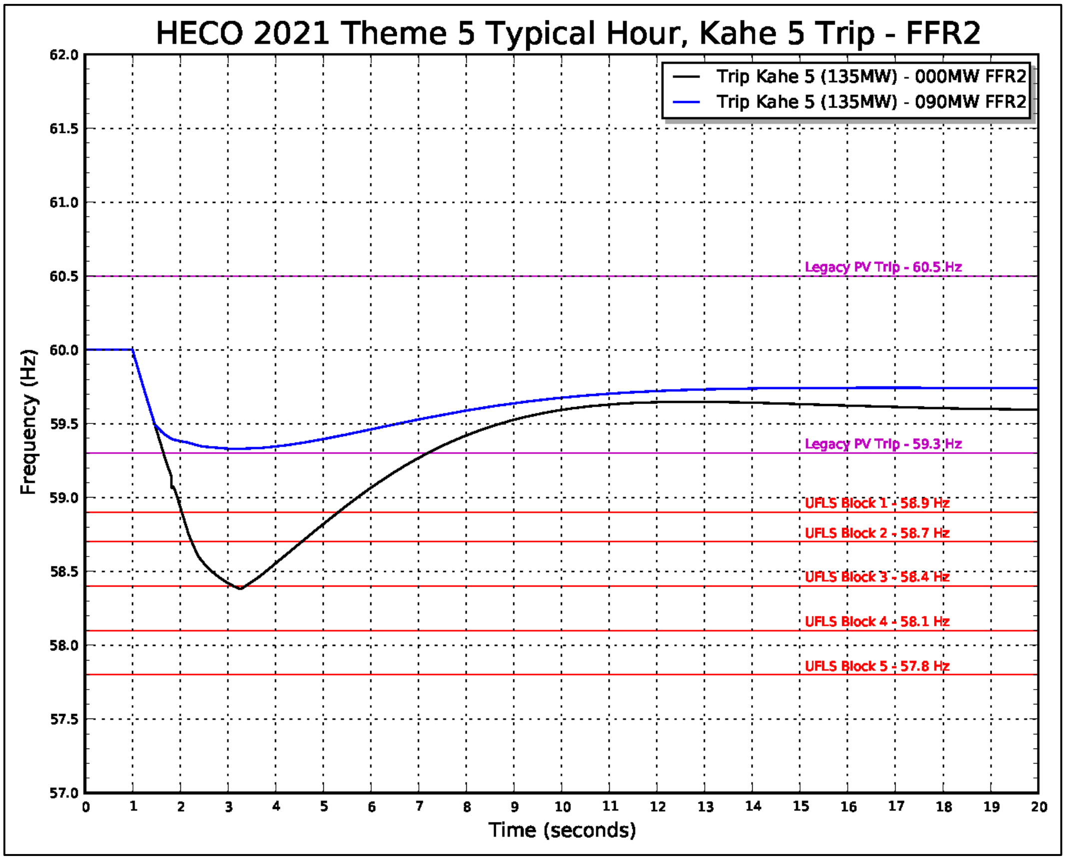

Figure O-63. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-63 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 90 MW.

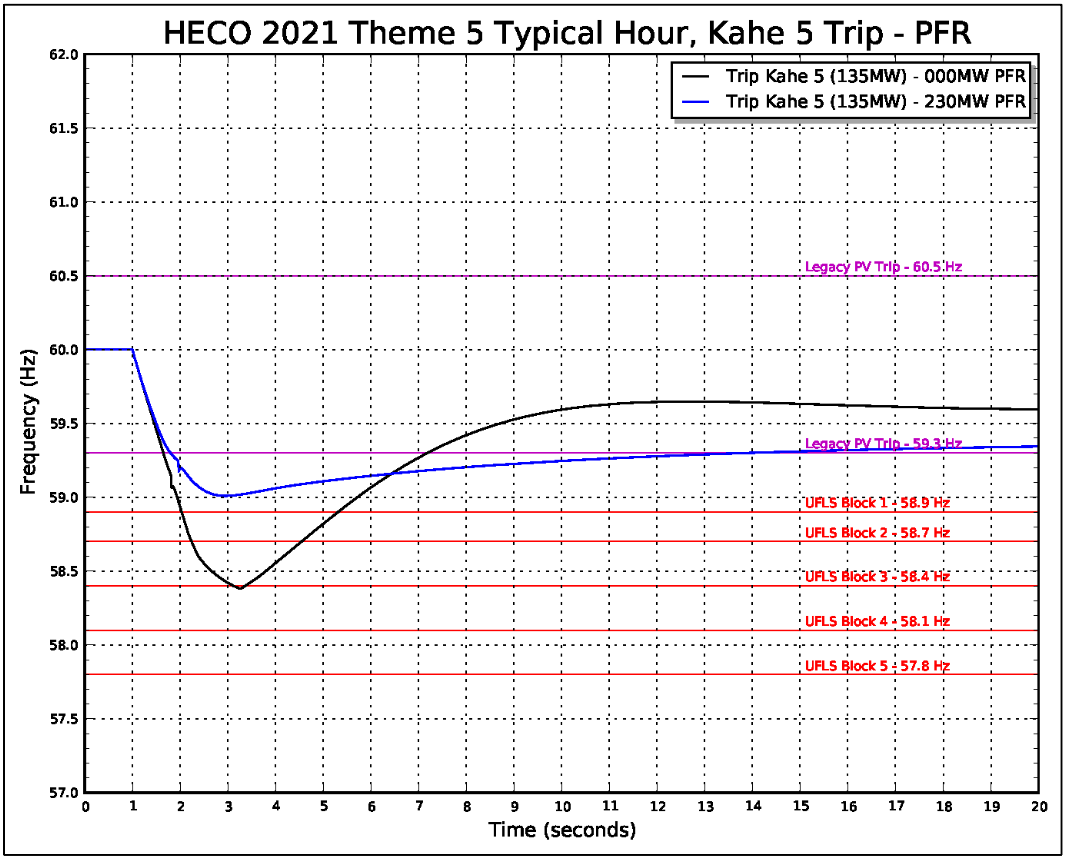

Figure O-64. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-64 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 230 MW. This is in addition to the 238 MW of upward regulation from thermal generation.

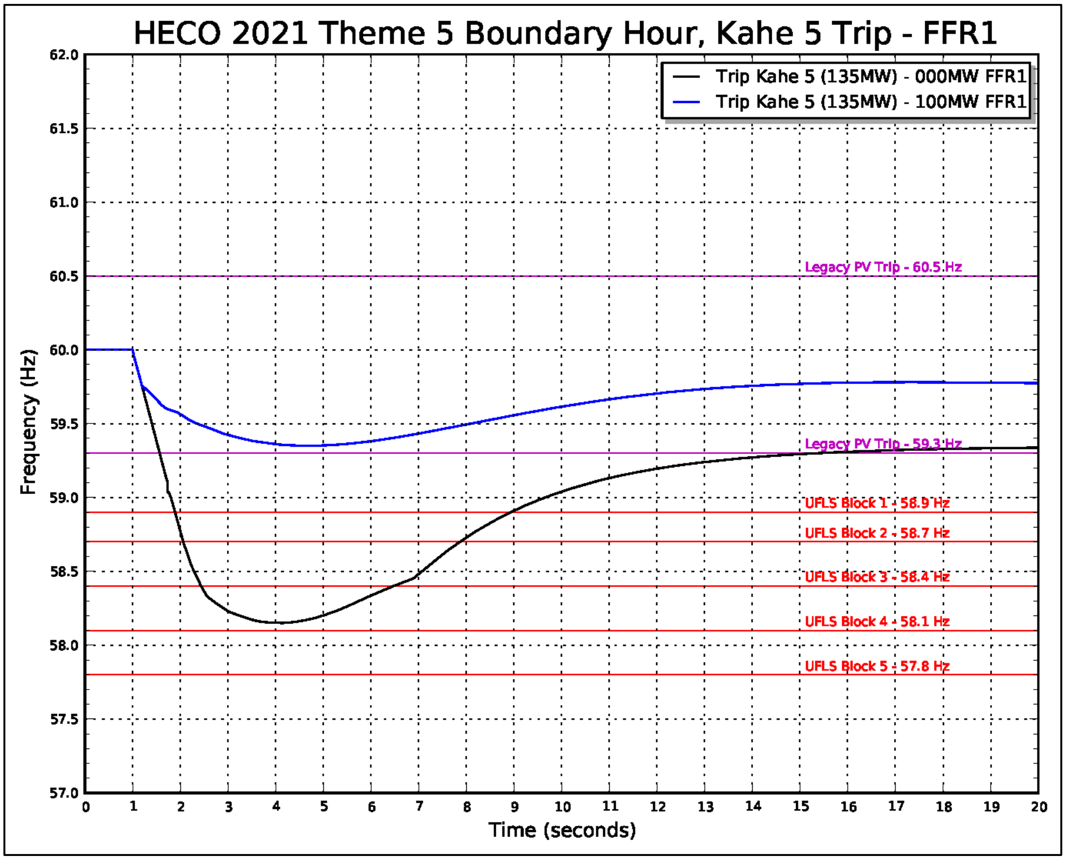

Figure O-65. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-65 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir breaches 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

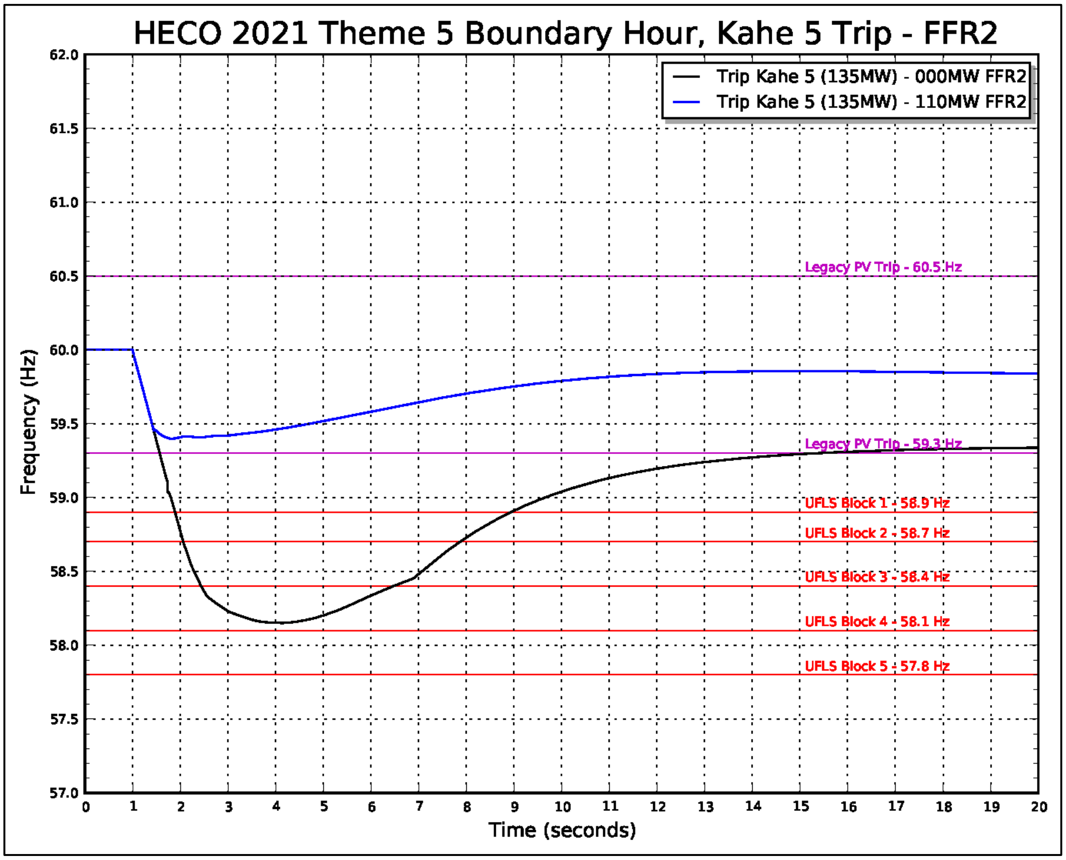

Figure O-66. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-66 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 110 MW.

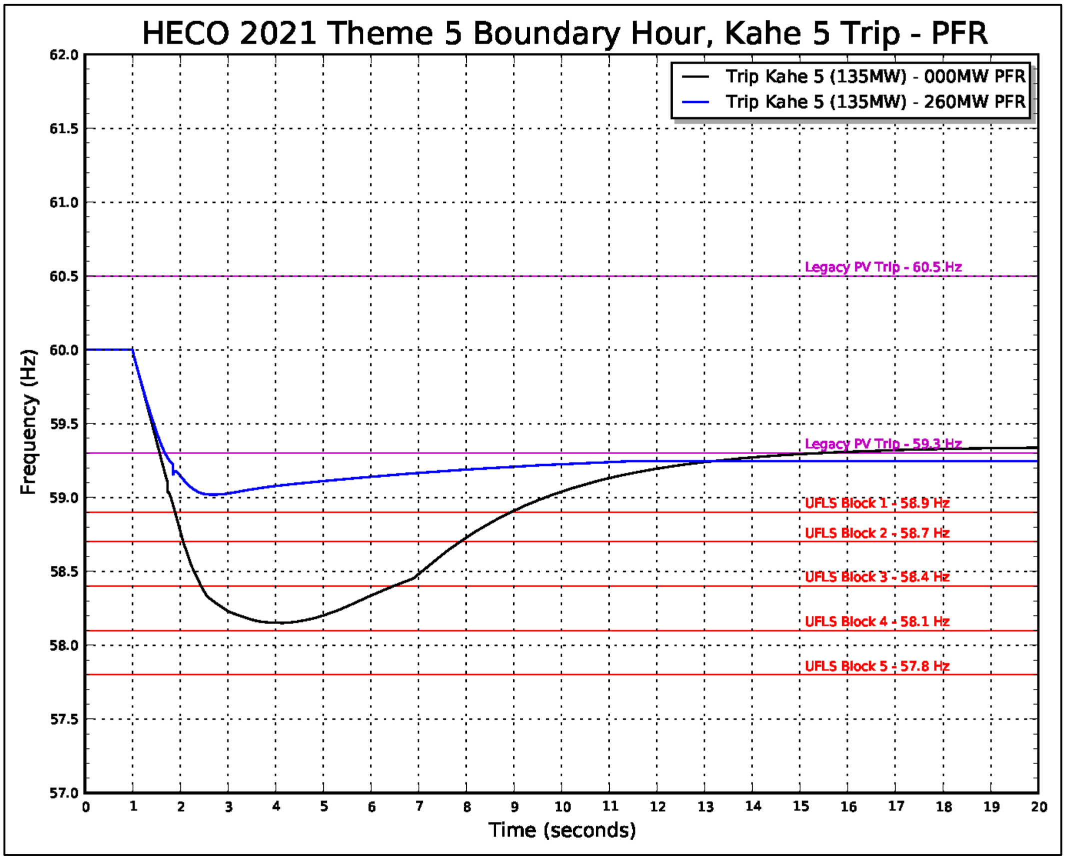

Figure O-67. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-67 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 153 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							Theme 5 - Fault Sun 7/18/21 Hour 14		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	26.6	19.4	1.6
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	27.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357			
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
JBPHH 1	16.8	6.7			0.99	21.8	22			
JBPHH 2	16.8	6.7			0.99	21.8	22			
JBPHH 3	16.8	6.7			0.99	21.8	22			
JBPHH 4	16.8	6.7			0.99	21.8	22			
JBPHH 5	16.8	6.7			0.99	21.8	22			
JBPHH 6	16.8	6.7			0.99	21.8	22			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163	0						46		
-Kahuku	30	0						11		
-Kawailoa	69	0						21		
-Na Pua Makani	24	0						5		
-CBRE Wind	10	0						0		
DG-PV	720	0						575		
Station PV	467	0						218		
Total Kinetic Energy									2094	
Total Load									1003	
Total Thermal Generation									165	
Total Renewable Generation									839	
Total Generation									1003	
Excess Generation									0	
Total Up Regulation									217	
Total Down Regulation									28	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		58.8
	60.5Hz Capacity			215.9				60.5Hz Output		172.7

Table O-35. Unit Commitment and Dispatch Fault Analysis

Table O-35 shows the unit commitment and dispatch for the fault analysis (7/18/2021, 2:00 PM).

Simulations for normally cleared faults were unstable for all 18 transmission circuits. The capacity of inverter-based generation has increased to the point where the margin of stability has been compromised.

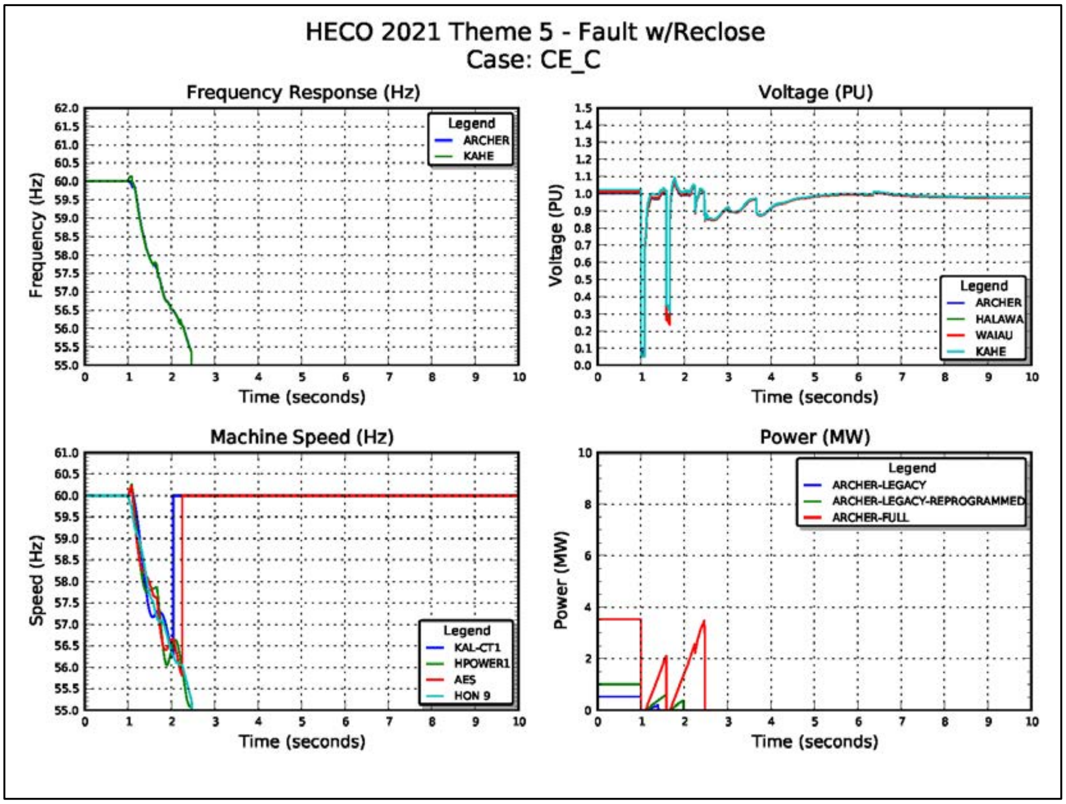

Figure O-68. System Performance Normally-Cleared Fault

Figure O-68 shows four plots that illustrates system performance for a fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation, essentially tripping 793 MW from the system. System frequency decays while system voltage is quickly restored on the breaker reclose. Generation from some DG-PV begins to recover upon restoration of voltage but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS cannot prevent system frequency from breaching 57.0 Hz. The remaining synchronous units trip on under frequency protection, causing the system to collapse. The plot at the bottom right shows the response of DG-PV at Archer Substation that is indicative of DG-PV performance across the entire system.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize the system.

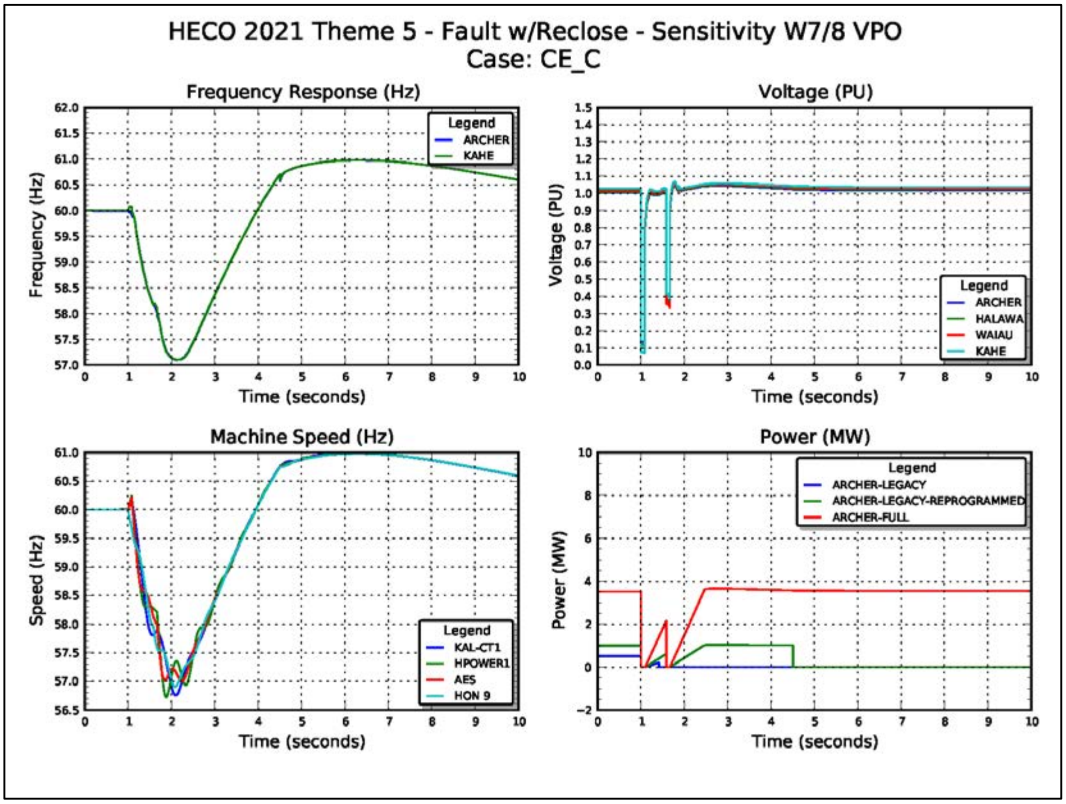

Figure O-69. System Performance Sensitivity Analysis VPO Units

Figure O-69 shows system performance with Waiau Units 7 and 8 operating in VPO. With additional synchronous units at Waiau, system voltage is momentarily suppressed but recovers above the 0.5 PU threshold before the 0.5 second trip setting so generation from full ride-through inverters is restored. The aggregate response of synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 57.2 Hz.

The system does not meet the requirements of TPL-001. Non-exhaustive sensitivity analyses were performed to bring the system into compliance with TPL-001.

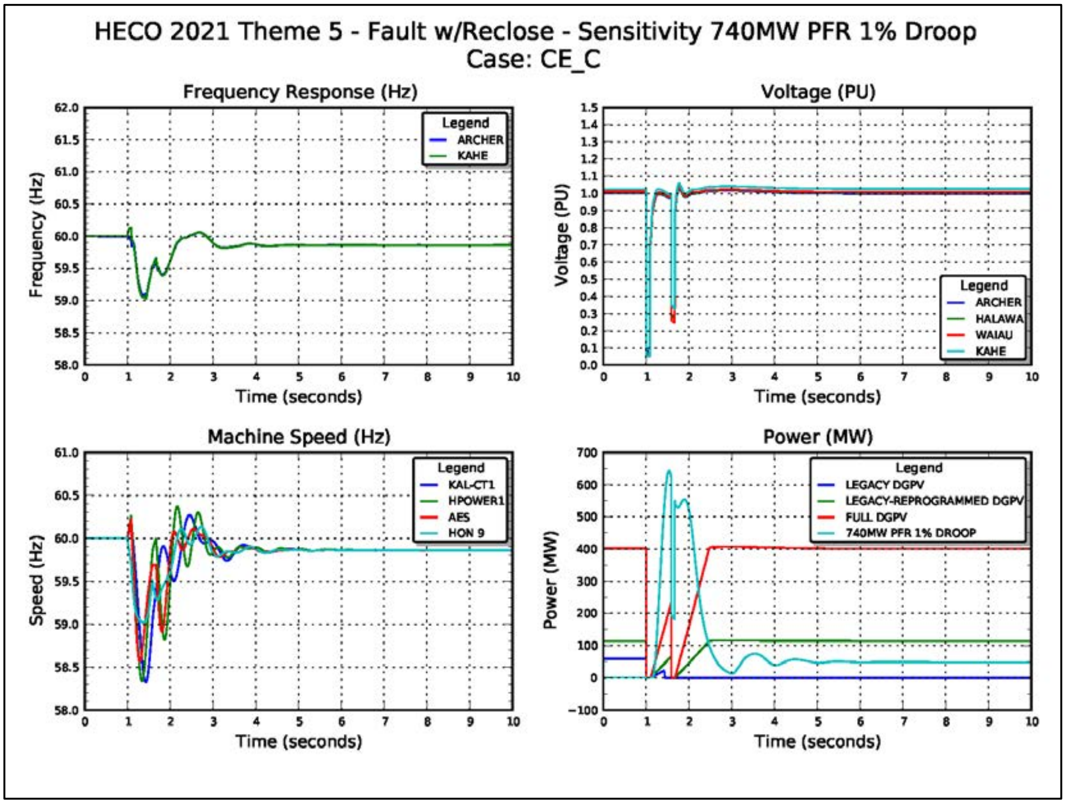

Figure O-70. System Performance Sensitivity Analysis 740 MW PFR

Figure O-70 shows system performance with the addition of the 740 MW of PFR at 1% droop response. For the purpose of this analysis, a 740 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, 740 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

2021 138 kV Fault Analysis				
Circuit Outage	Reclose TD	Fault Hour Condition	Waiau 7/8 VPO Mitigation	740 MW PFR Mitigation
CEIP-Ewa Nui	30	Unstable	Stable	Stable
Halawa-Iwilei	30	Unstable	Stable	Stable
Halawa-Koolau	30	Unstable	Stable	Stable
Halawa-School	30	Unstable	Stable	Stable
Kahe-CEIP 1	30	Unstable	Stable	Stable
Kahe-CEIP 2	30	Unstable	Stable	Stable
Kalaeloa-Ewa Nui	30	Unstable	Stable	Stable
Kahe-Halawa 1	30	Unstable	Stable	Stable
Kahe-Halawa 2	30	Unstable	Stable	Stable
Kahe-Waiau	30	Unstable	Stable	Stable
Makalapa-Airport	30	Unstable	Stable	Stable
Waiau-Ewa Nui 1	30	Unstable	Stable	Stable
Waiau-Ewa Nui 2	30	Unstable	Stable	Stable
Waiau-Koolau 1	30	Unstable	Stable	Stable
Waiau-Koolau 2	30	Unstable	Stable	Stable
Waiau-Makalapa 1	30	Unstable	Stable	Stable
Waiau-Makalapa 2	30	Unstable	Stable	Stable
Waiau-Wahiawa	30	Unstable	Stable	Stable

Table O-36. Summary of Results Normally-Cleared Faults

Table O-36 shows the results of the normal clearing fault analysis. Simulations of a normally cleared fault resulted in system collapse for all transmission circuits. Committing Waiau Units 7 and 8 in VPO can help stabilize system frequency but multiple blocks of UFLS was also required.

The system requires 740 MW of PFR at 1% droop response to meet the requirements of TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2022

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

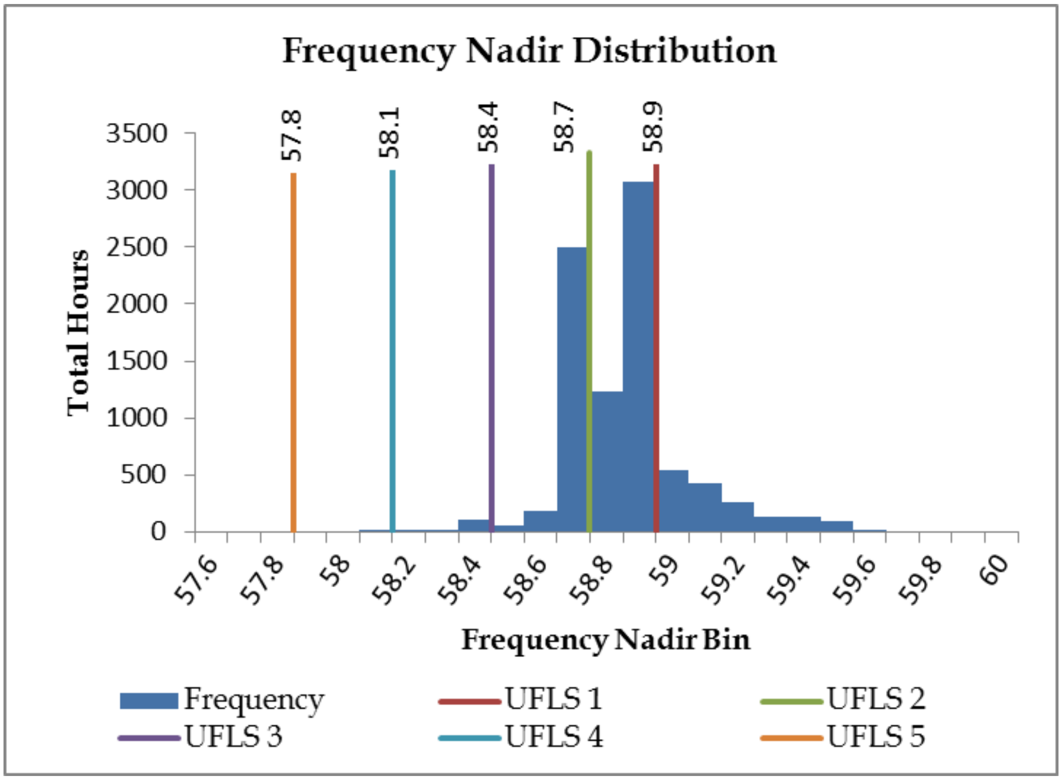

Figure O-71. Frequency Nadir Histogram 2022

Figure O-71 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 1155 hours was 5:00 PM on Tuesday, August 16. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 12 hours was 10:00 AM on Friday, August 5. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

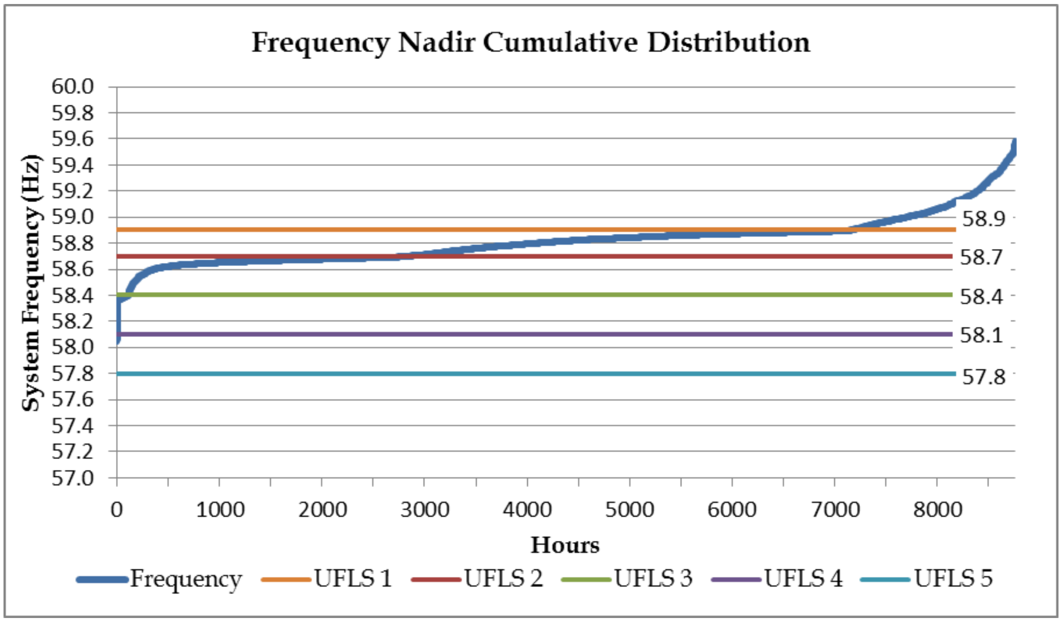

Figure O-72. Frequency Nadir Duration Curve 2022

Figure O-72 shows the frequency nadir duration curve for 2022. The system is at risk of UFLS for 7484 hours of the year.

Unit	Unit Ratings							Theme 5 - AES Trip Typical Tue 8/16/22 Hour 17			Theme 5 - AES Trip Boundary Fri 8/5/22 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	45.5	0.5	20.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	20.7	1.8	10.7	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8	58.5	25.5	29.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.0	1.0	29.0	27.9	12.1	17.9
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8	58.5	25.5	29.5
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	29.3	105.3	8.3			
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						54			45		
-Kahuku	30	0						10			14		
-Kawailoa	69	0						16			21		
-Na Pua Makani	24	0						16			2		
-CBRE Wind	10	0						3			2		
DG-PV	740	0						294			297		
Station PV	547	0						317			163		
Total Kinetic Energy									3378			2686	
Total Load									1151			909	
Total Thermal Generation									487			402	
Total Renewable Generation									664			506	
Total Generation									1151			909	
Excess Generation									0			0	
Total Up Regulation									113			63	
Total Down Regulation									300			236	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		29.4	59.3Hz Output		29.4
	60.5Hz Capacity			215.9				60.5Hz Output		86.4	60.5Hz Output		86.4

Table O-37. Unit Commitment and Dispatch 2022

Table O-37 shows the unit commitment and dispatch for the typical hour (8/16/22, 5:00 PM) and boundary hour (8/5/22, 10:00 AM).

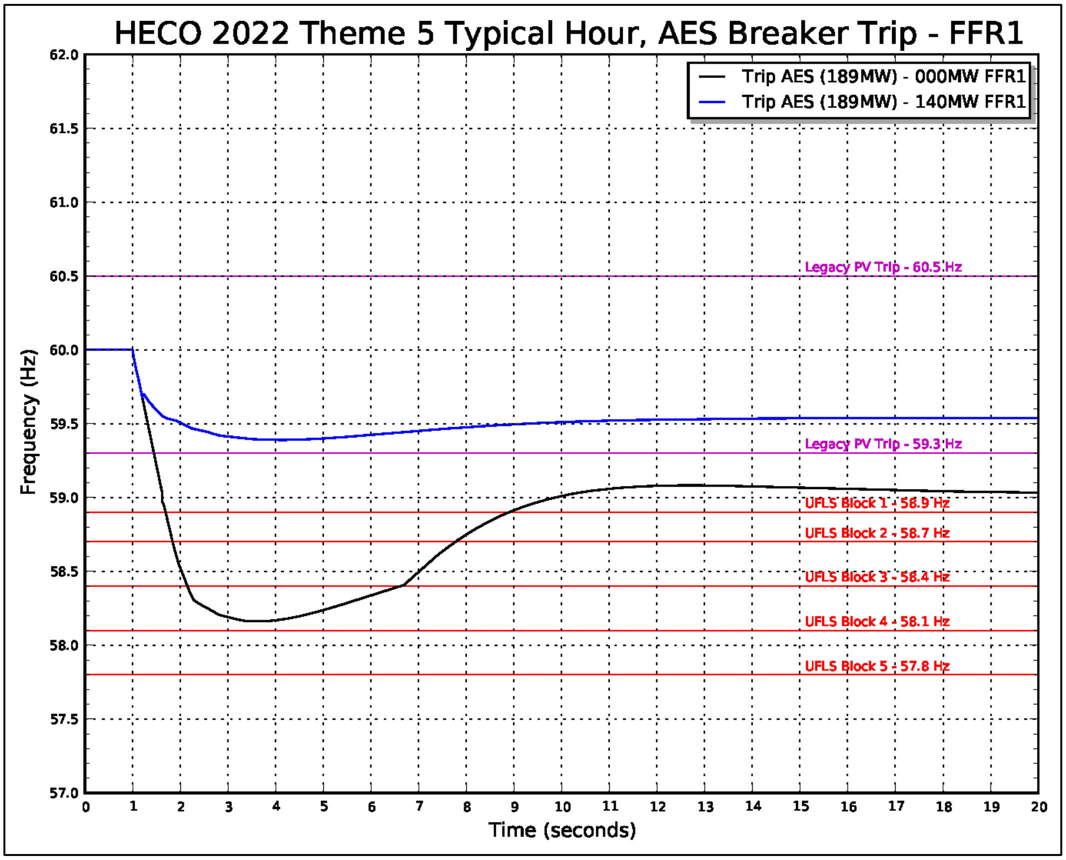

Figure O-73. Frequency Response Profile FFR1 Typical Hour

Figure O-73 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

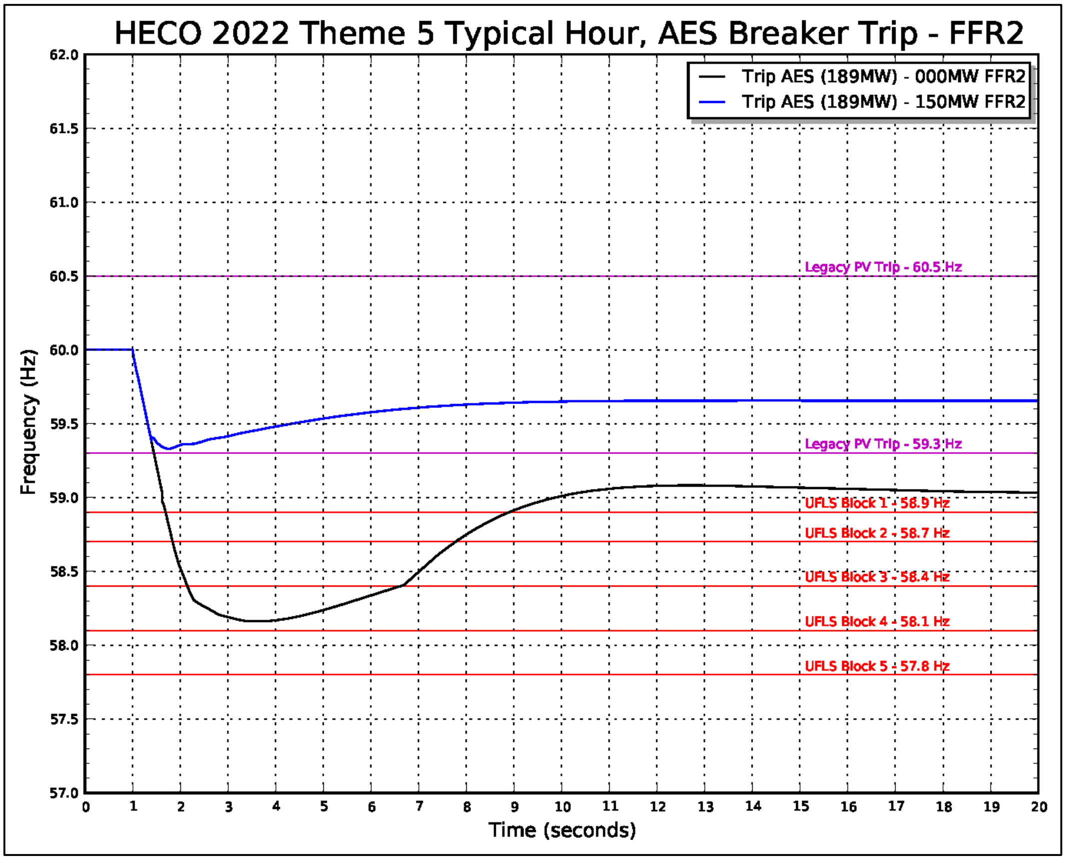

Figure O-74. Frequency Response Profile FFR2 Typical Hour

Figure O-74 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 150 MW.

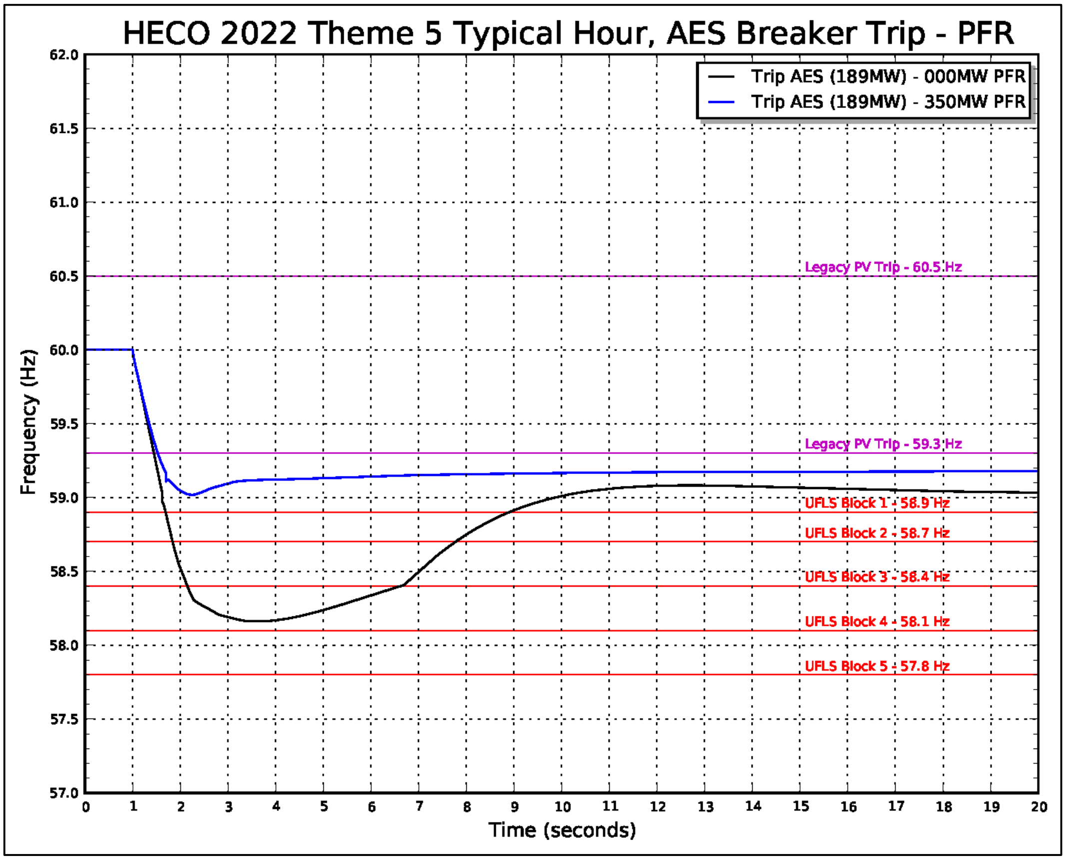

Figure O-75. Frequency Response Profile PFR Typical Hour

Figure O-75 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 350 MW. This is in addition to the 113 MW of upward regulation from thermal generation.

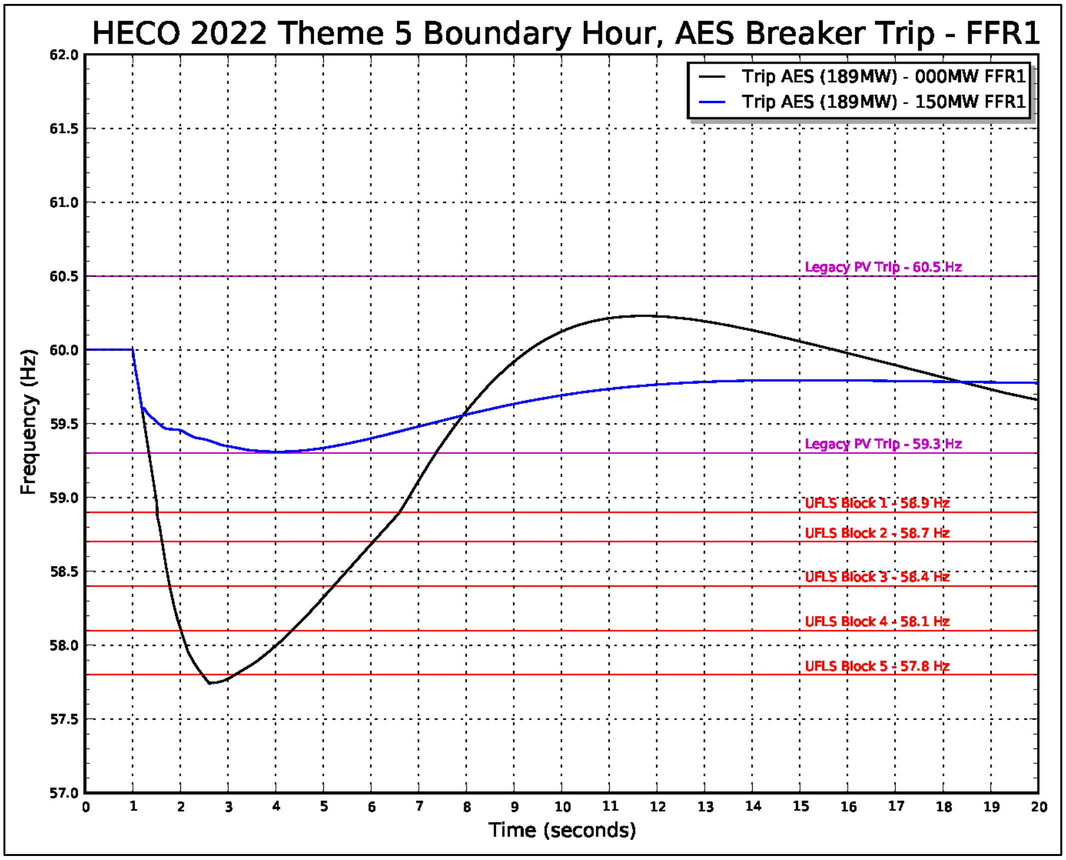

Figure O-76. Frequency Response Profile FFR1 Boundary Hour

Figure O-76 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 2686 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 57.7 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

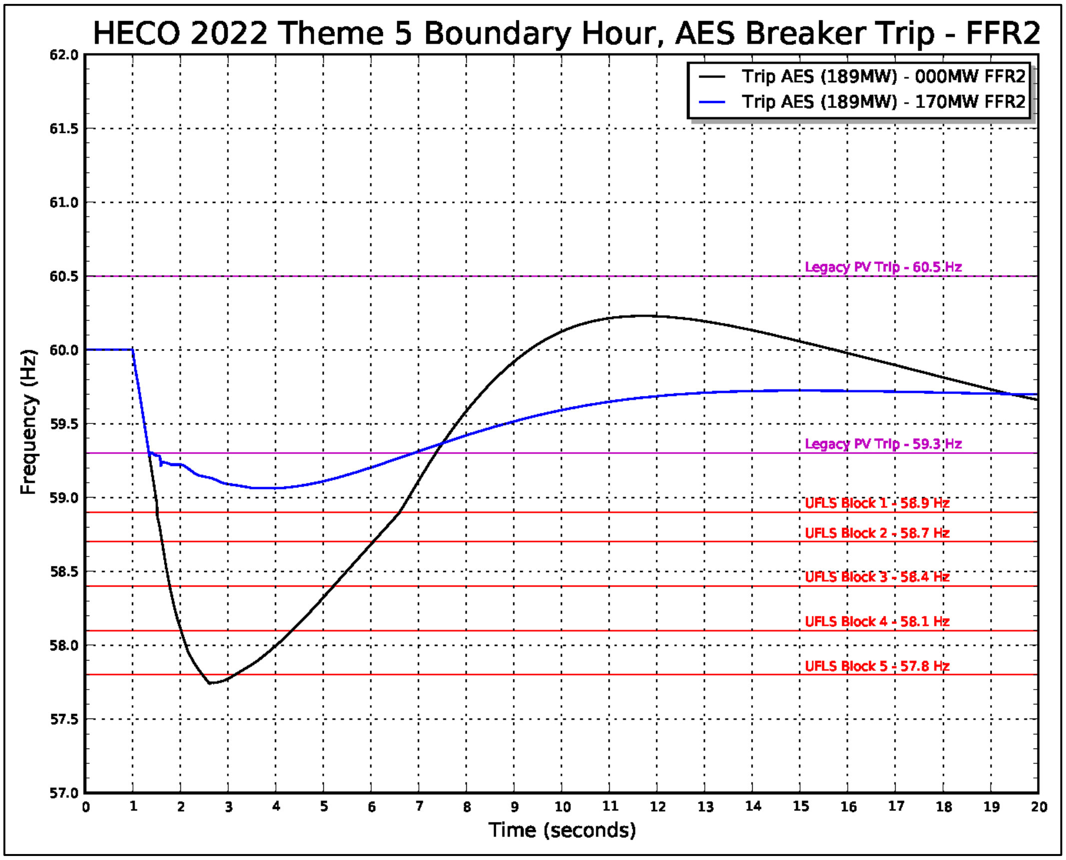

Figure O-77. Frequency Response Profile FFR2 Boundary Hour

Figure O-77 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 170 MW.

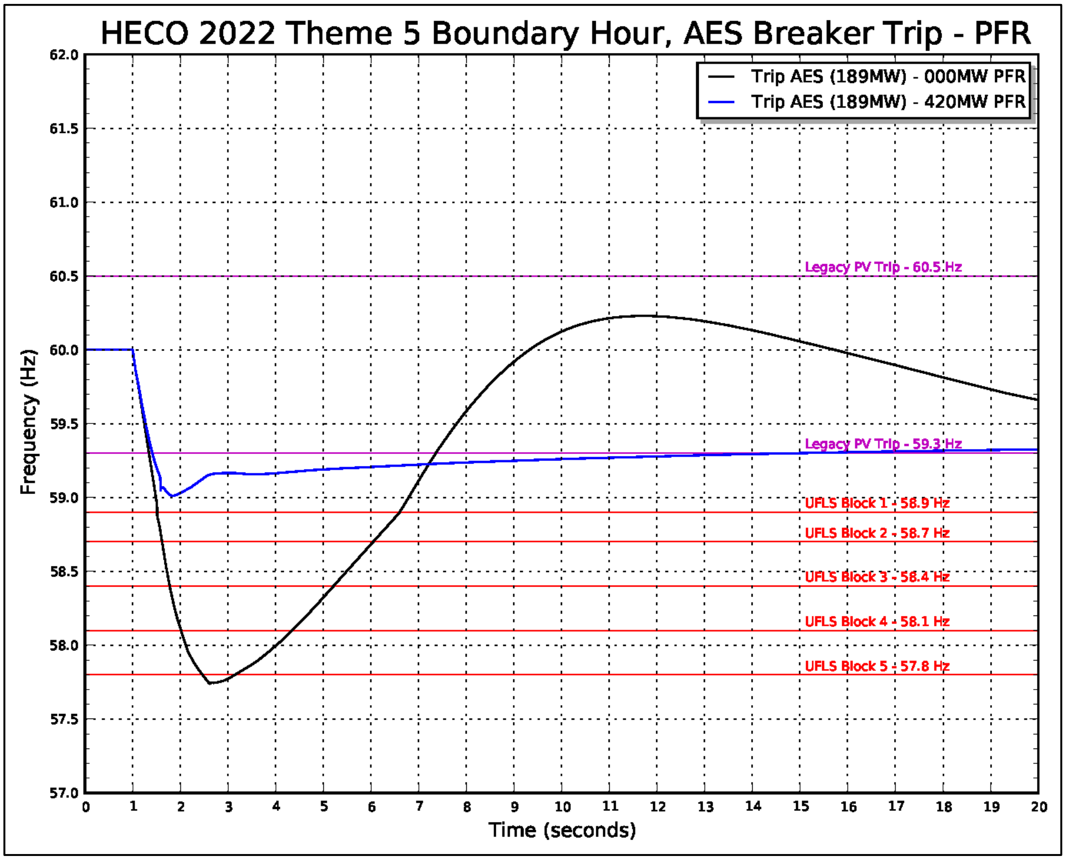

Figure O-78. Frequency Response Profile PFR Boundary Hour

Figure O-78 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 420 MW. This is in addition to the 63 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Tue 8/16/22 Hour 17			Theme 5 - K5 Trip Boundary Fri 8/5/22 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	45.5	0.5	20.5	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	20.7	1.8	10.7	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	84.0	105.0	21.0	95.0	94.0	32.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.0	1.0	29.0	20.0	0.0	10.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	81.8	2.2	52.8			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						54			45		
-Kahuku	30	0						10			14		
-Kawailoa	69	0						16			21		
-Na Pua Makani	24	0						16			2		
-CBRE Wind	10	0						3			2		
DG-PV	740	0						294			297		
Station PV	547	0						317			163		
Total Kinetic Energy									3378			2787	
Total Load									1151			909	
Total Thermal Generation									487			402	
Total Renewable Generation									664			506	
Total Generation									1152			908	
Excess Generation									0			0	
Total Up Regulation									113			94	
Total Down Regulation									300			244	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		29.4	59.3Hz Output		29.4
	60.5Hz Capacity			215.9				60.5Hz Output		86.4	60.5Hz Output		86.4

Table O-38. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-38 shows the unit commitment and dispatch for the typical hour (5/26/22, 3:00 PM) and boundary hour (7/10/2022, 9:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

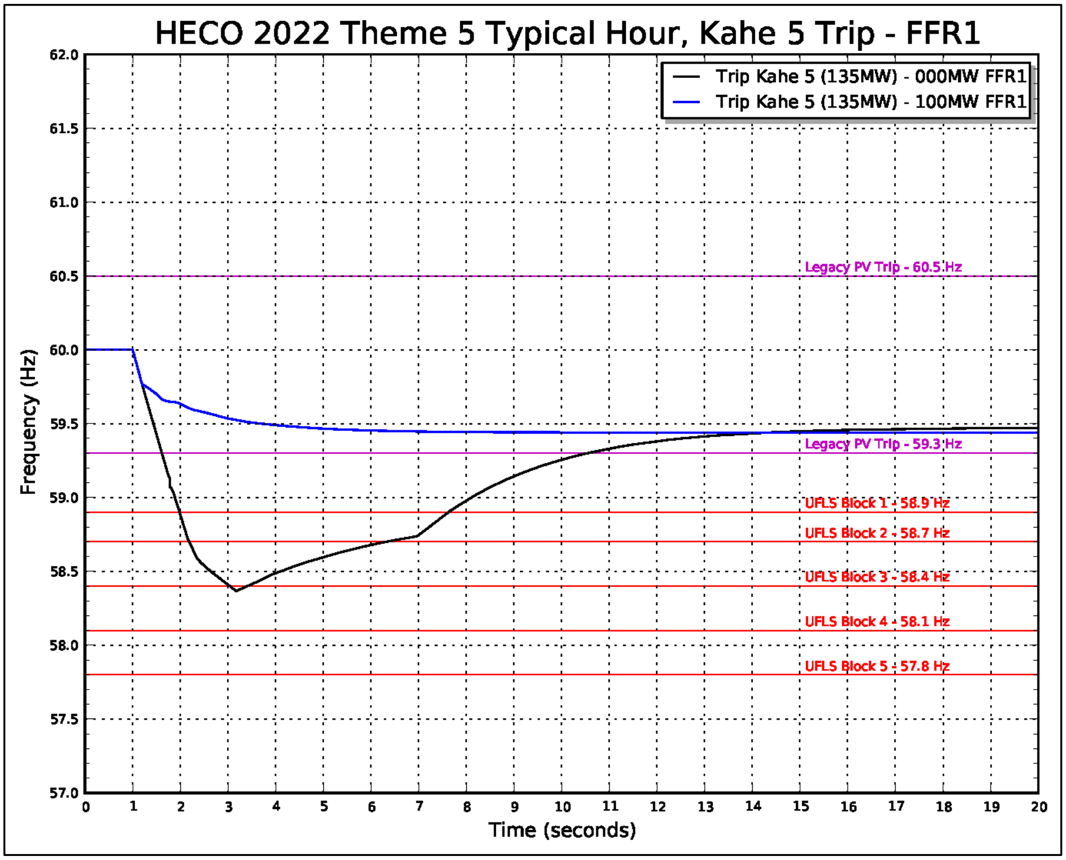

Figure O-79. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-79 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3378 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

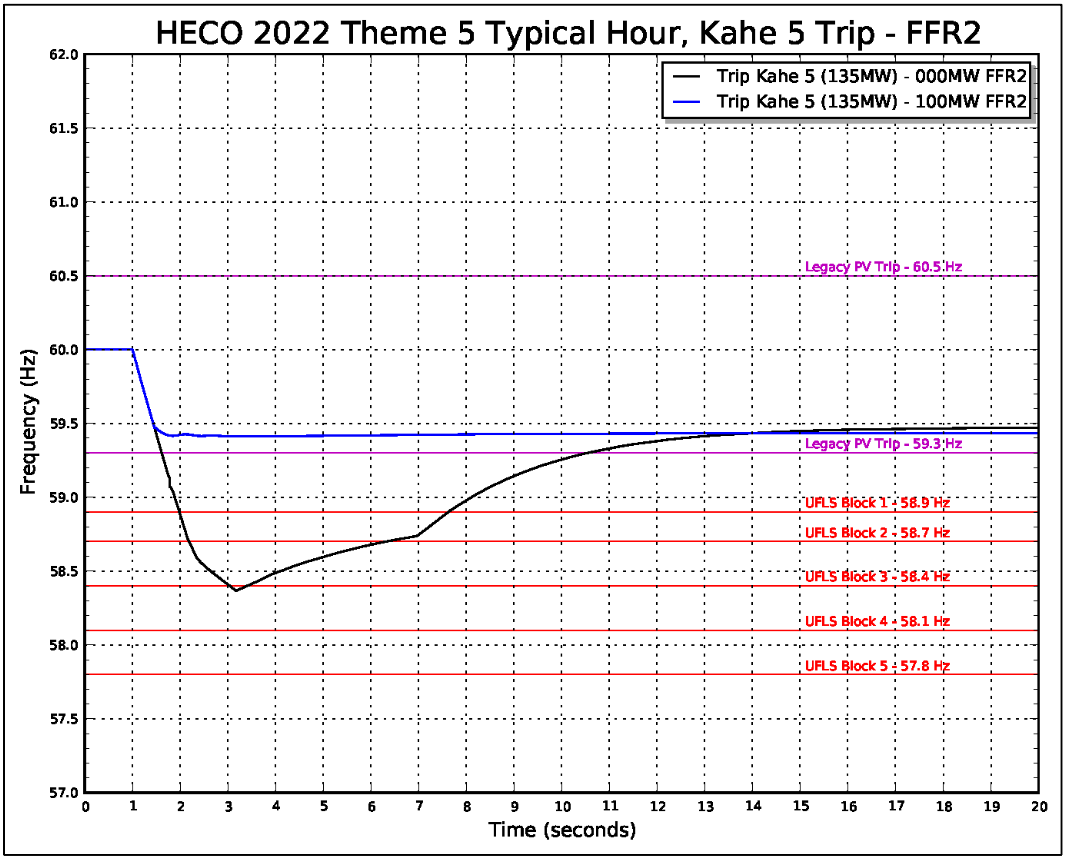

Figure O-80. Frequency Response Profile FFR2 Sensitivity Typical Hour

Figure O-80 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 100 MW.

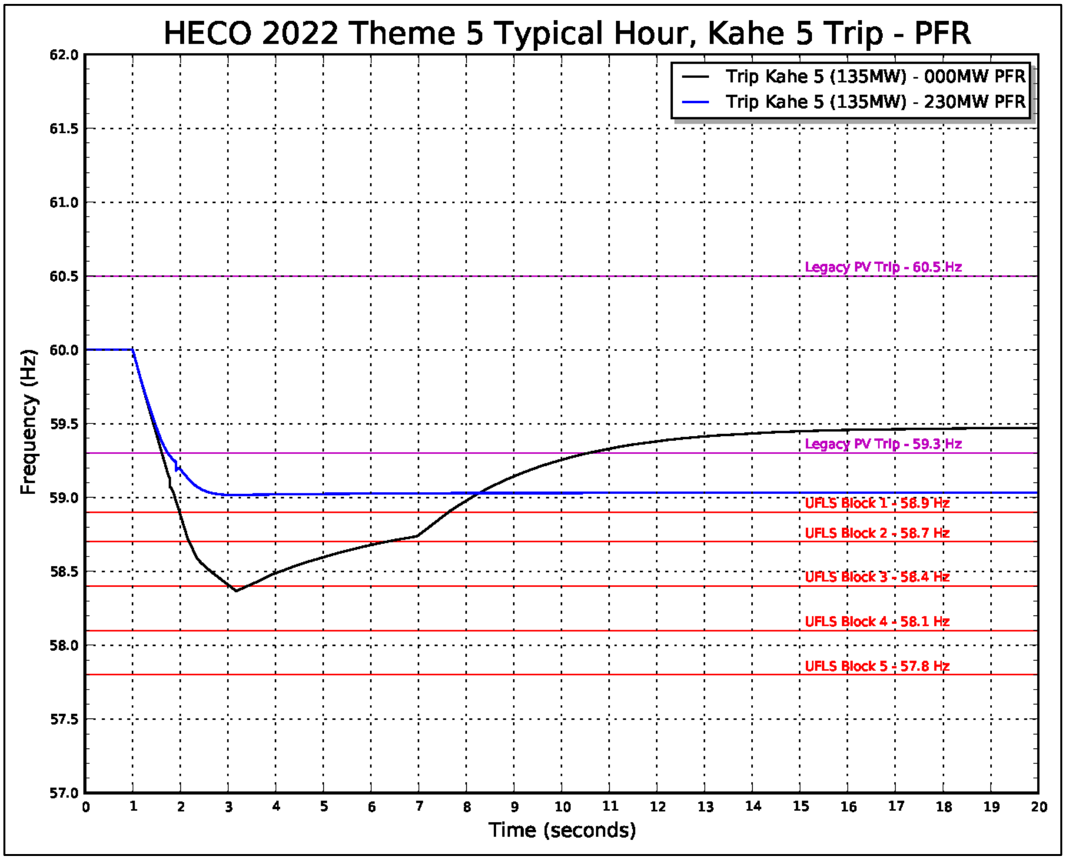

Figure O-81. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-81 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 230 MW. This is in addition to the 113 MW of upward regulation in from thermal generation.

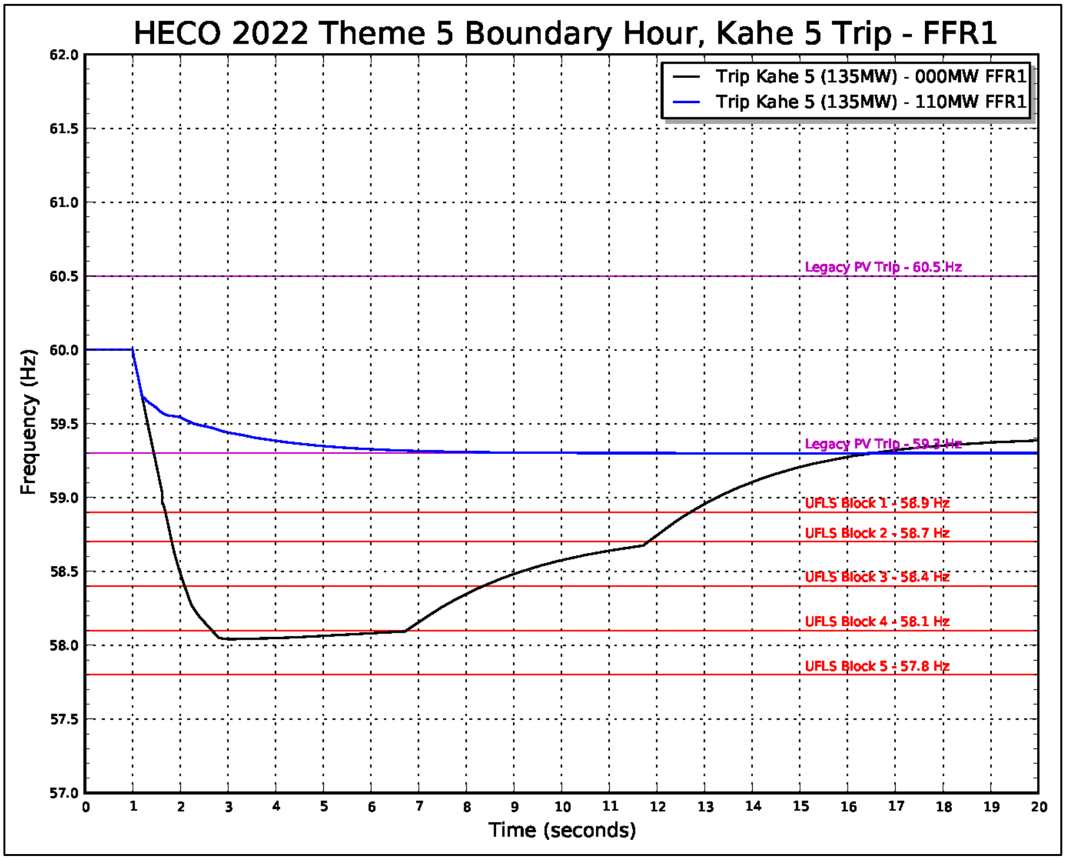

Figure O-82. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-82 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 2787 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW.

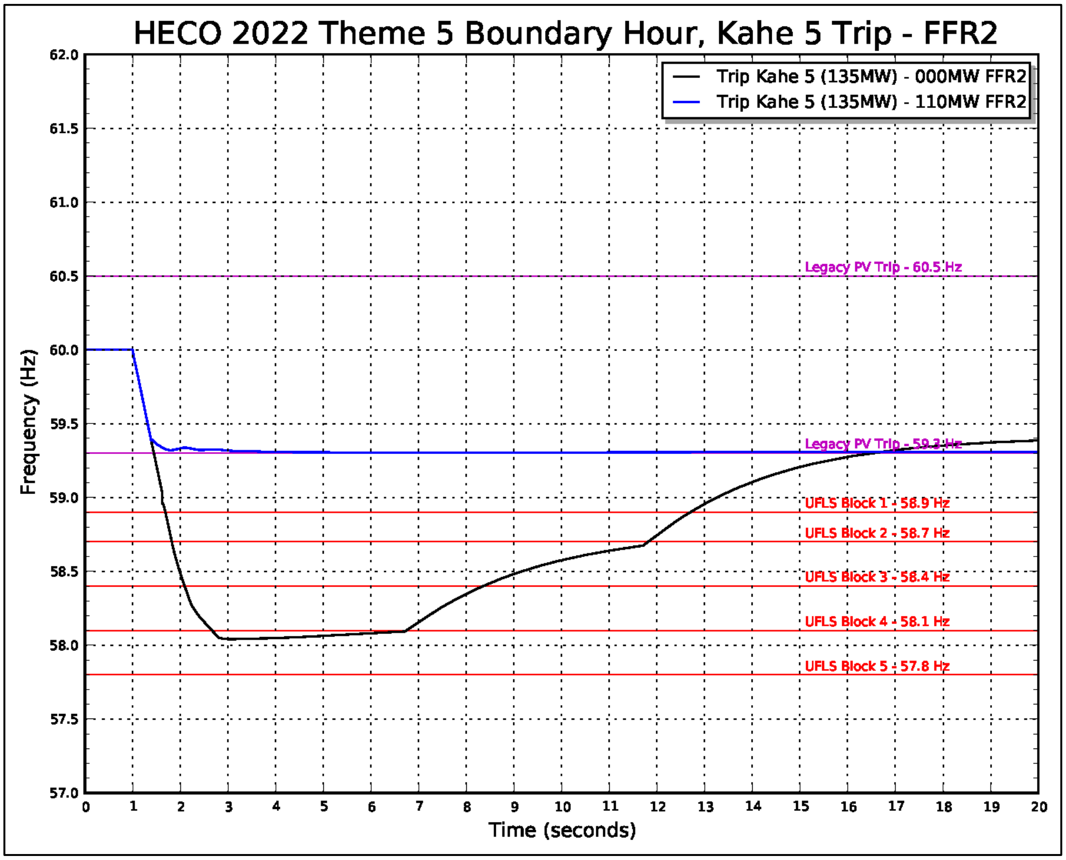

Figure O-83. Frequency Response Profile FFR2 Sensitivity Boundary Hour

Figure O-83 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance is 110 MW.

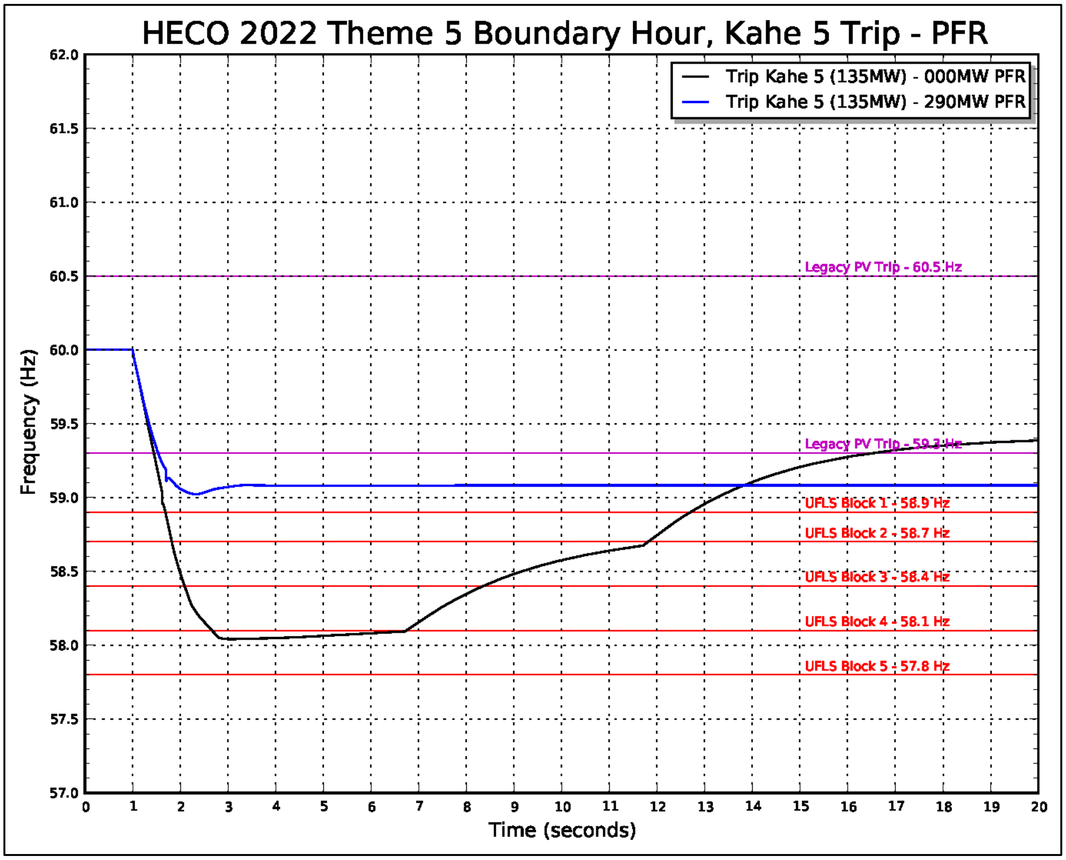

Figure O-84. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-84 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 290 MW. This is in addition to the 63 MW of upward regulation from thermal generation.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

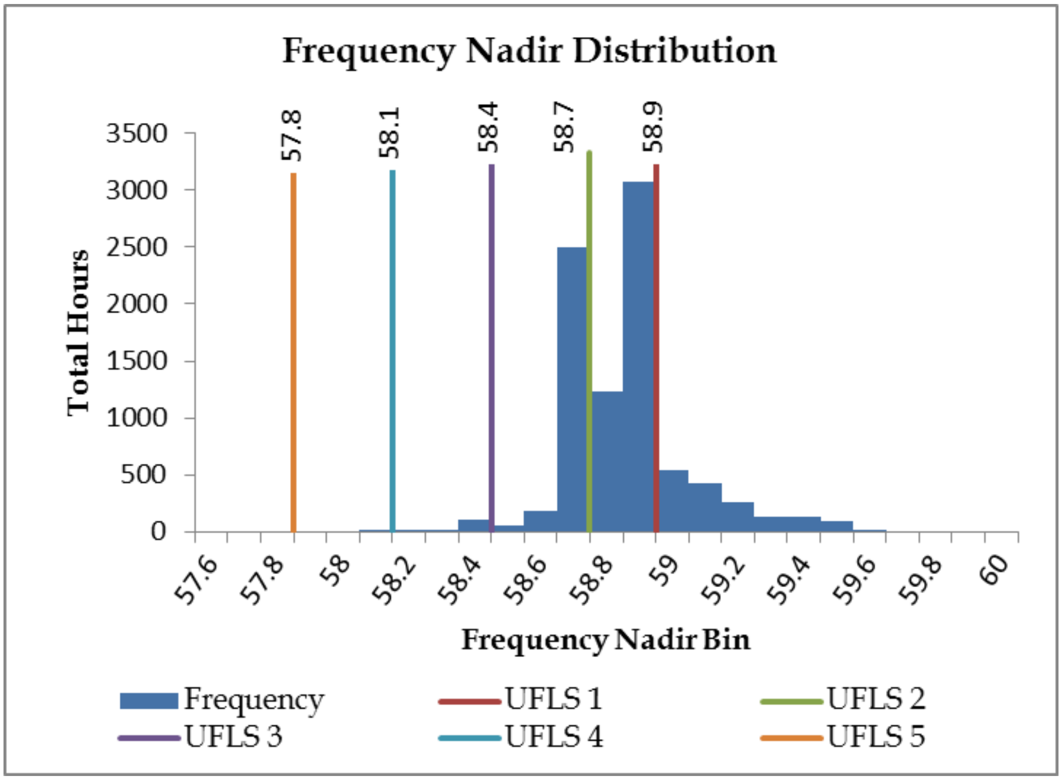

Figure O-85. Frequency Nadir Histogram 2023

Figure O-85 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 2494 hours was 9:00 PM on Friday, July 14. The frequency nadir range for the typical hour is 58.6- 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 1 hour was 10:00 AM on Sunday, January 22. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires four blocks of UFLS to stabilize system frequency.

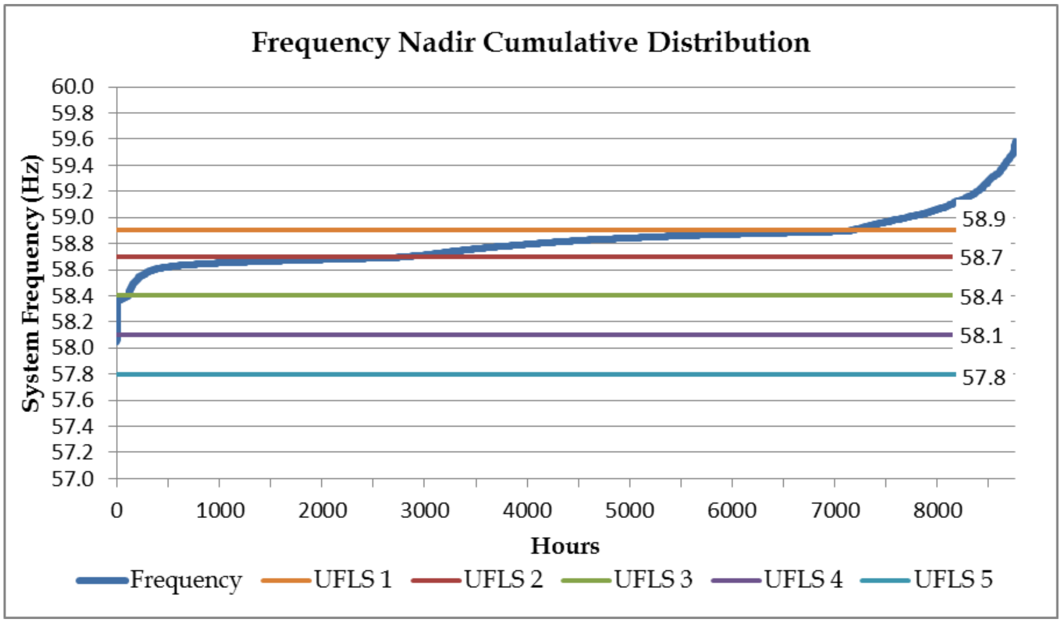

Figure O-86. Frequency Nadir Duration Curve 2023

Figure O-86 shows the frequency nadir duration curve for 2023. The system is at risk of UFLS for 7159 hours of the year.

Unit	Unit Ratings							Theme 5 - K5 Trip Typical Fri 7/14/23 Hour 9			Theme 5 - K5 Trip Boundary Sun 1/22/23 Hour 10		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	41.5	4.5	16.5
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0	22.5	0.0	12.5
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0			
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	63.1	19.1	39.3			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357				71.8	14.4	48.1
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	80.7	4.6	57.1			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	127.7	6.9	106.7
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						70			19		
-Kahuku	30	0						13			5		
-Kawailoa	69	0						24			6		
-Na Pua Makani	24	0						21			0		
-CBRE Wind	10	0						3			2		
DG-PV	755	0						160			288		
Station PV	607	0						212			335		
Total Kinetic Energy									3546			1651	
Total Load									973			906	
Total Thermal Generation									532			263	
Total Renewable Generation									442			642	
Total Generation									973			906	
Excess Generation									0			0	
Total Up Regulation									47			26	
Total Down Regulation									361			184	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		14.7	59.3Hz Output		29.4
	60.5Hz Capacity		215.9					60.5Hz Output		43.2	60.5Hz Output		86.4

Table O-39. Unit Commitment and Dispatch 2023

Table O-39 shows the unit commitment and dispatch for the typical hour (7/14/23, 9:00 AM) and boundary hour (1/22/23, 10:00 AM).

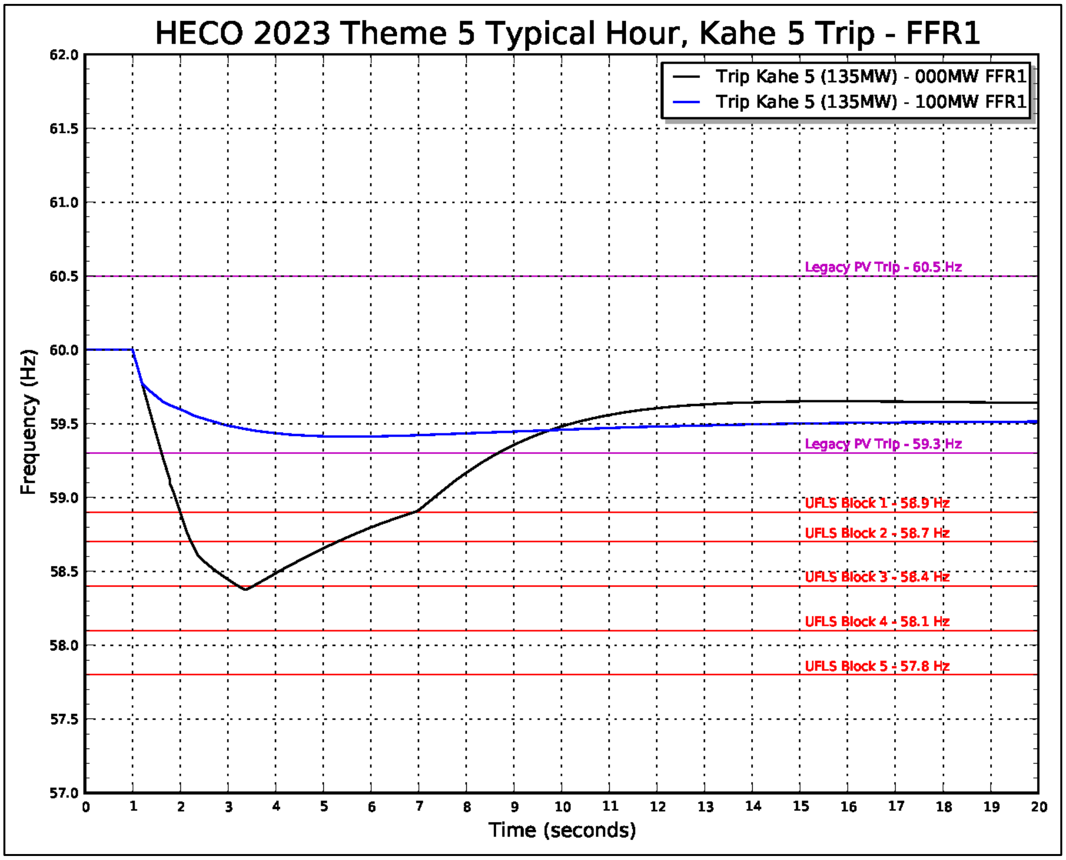

Figure O-87. Frequency Response Profile FFR1 Typical Hour

Figure O-87 shows the frequency response profile for a Kahe 5 trip for a typical hour. System kinetic energy is 3546 MW-sec and the capacity of legacy PV that will disconnect from the system is 14.7 MW. With no FFR, the frequency nadir is 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

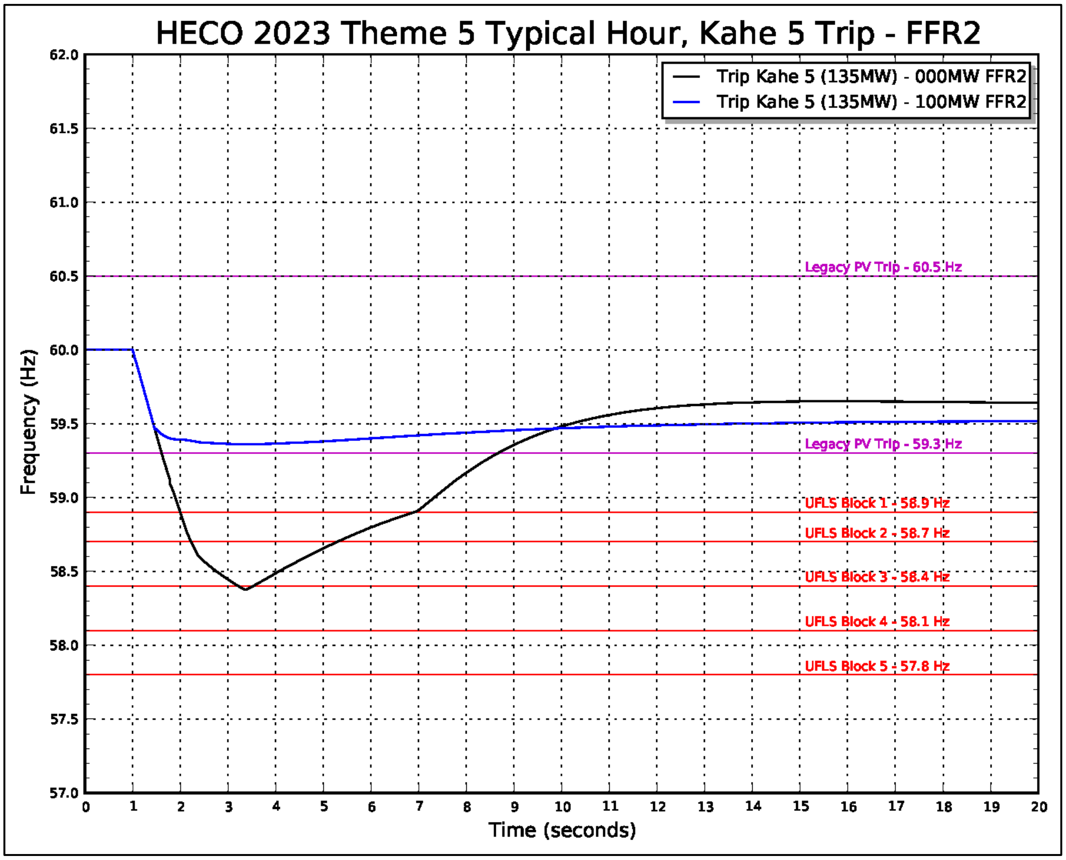

Figure O-88. Frequency Response Profile FFR2 Typical Hour

Figure O-88 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 100 MW.

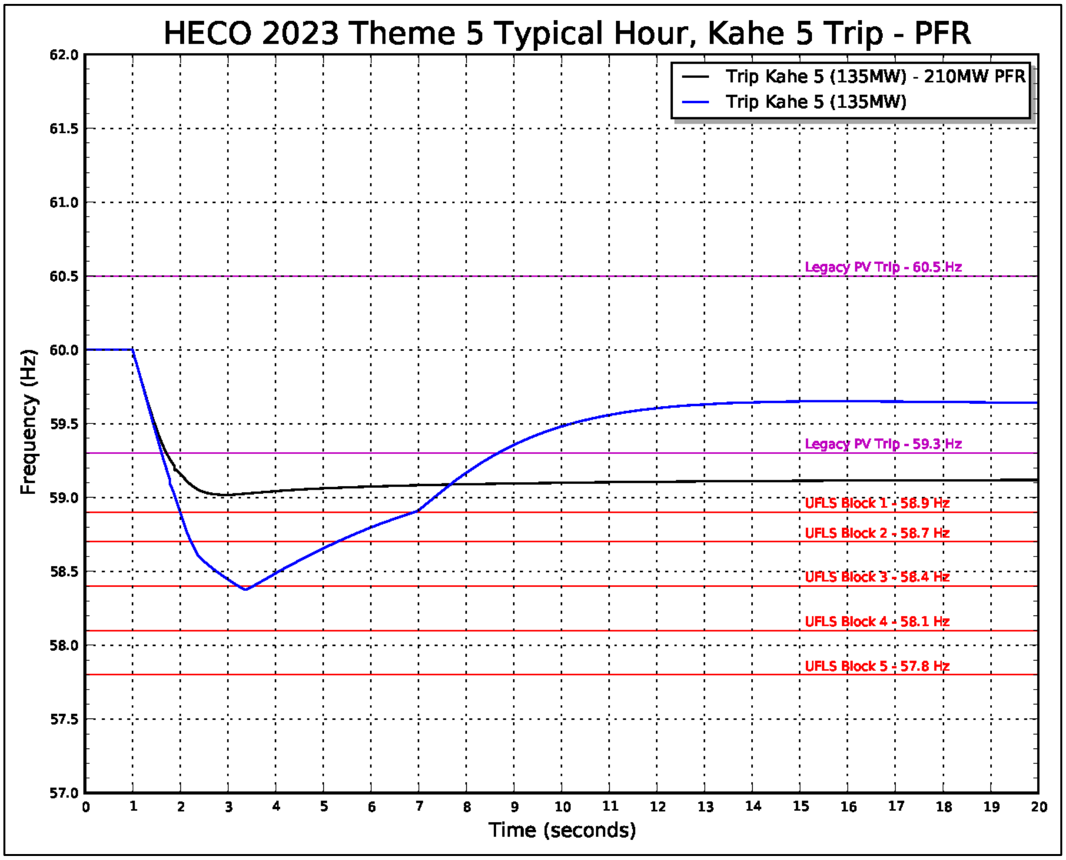

Figure O-89. Frequency Response Profile PFR Typical Hour

Figure O-89 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 210 MW. This is in addition to the 47 MW of upward regulation from thermal generation.

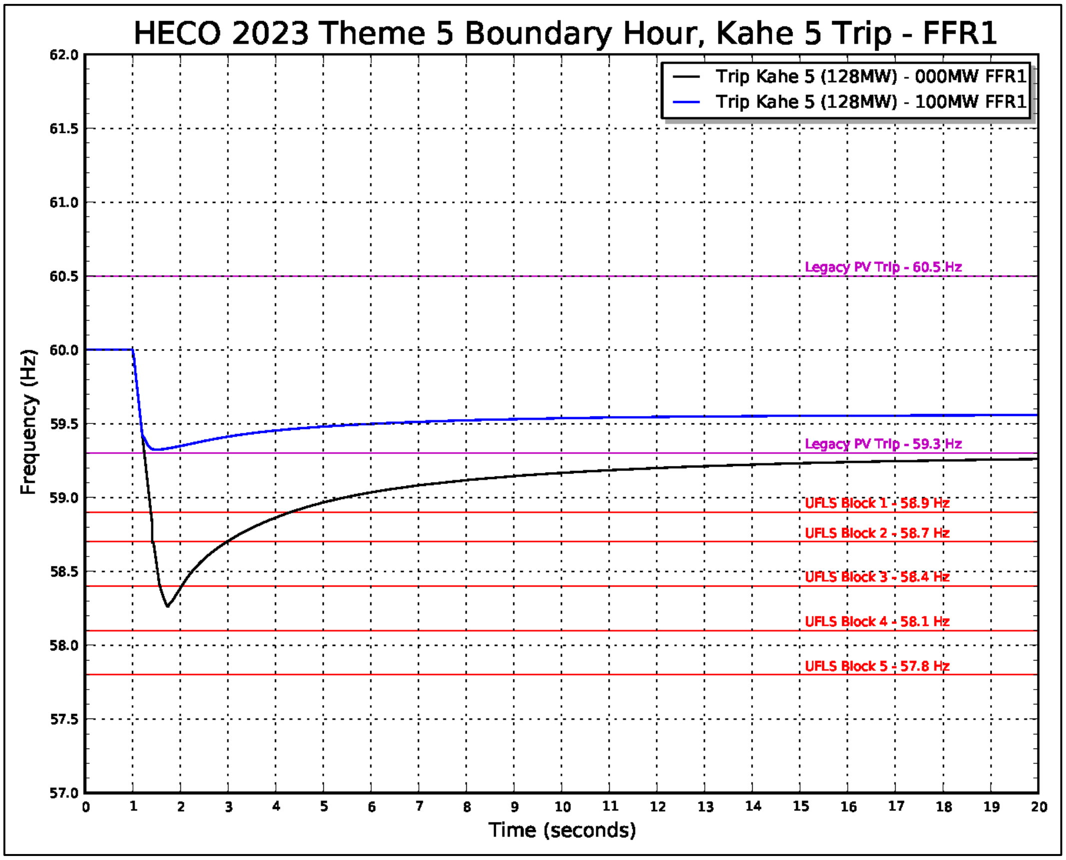

Figure O-90. Frequency Response Profile FFR1 Boundary Hour

Figure O-90 shows the frequency response profile for a Kahe 5 trip for a boundary hour. System kinetic energy is 1651 MW-sec and the capacity of legacy PV that will disconnect from the system is 29.4 MW. With no FFR, the frequency nadir is 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW.

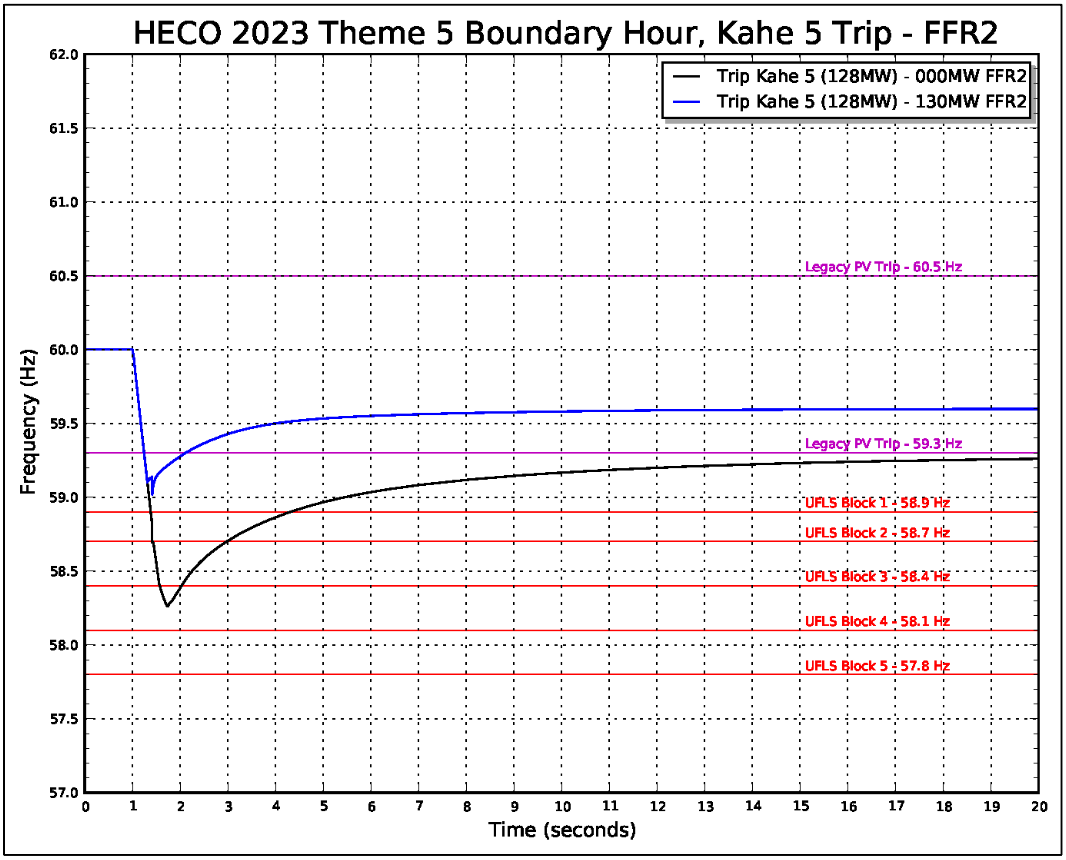

Figure O-91. Frequency Response Profile FFR2 Boundary Hour

Figure O-91 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

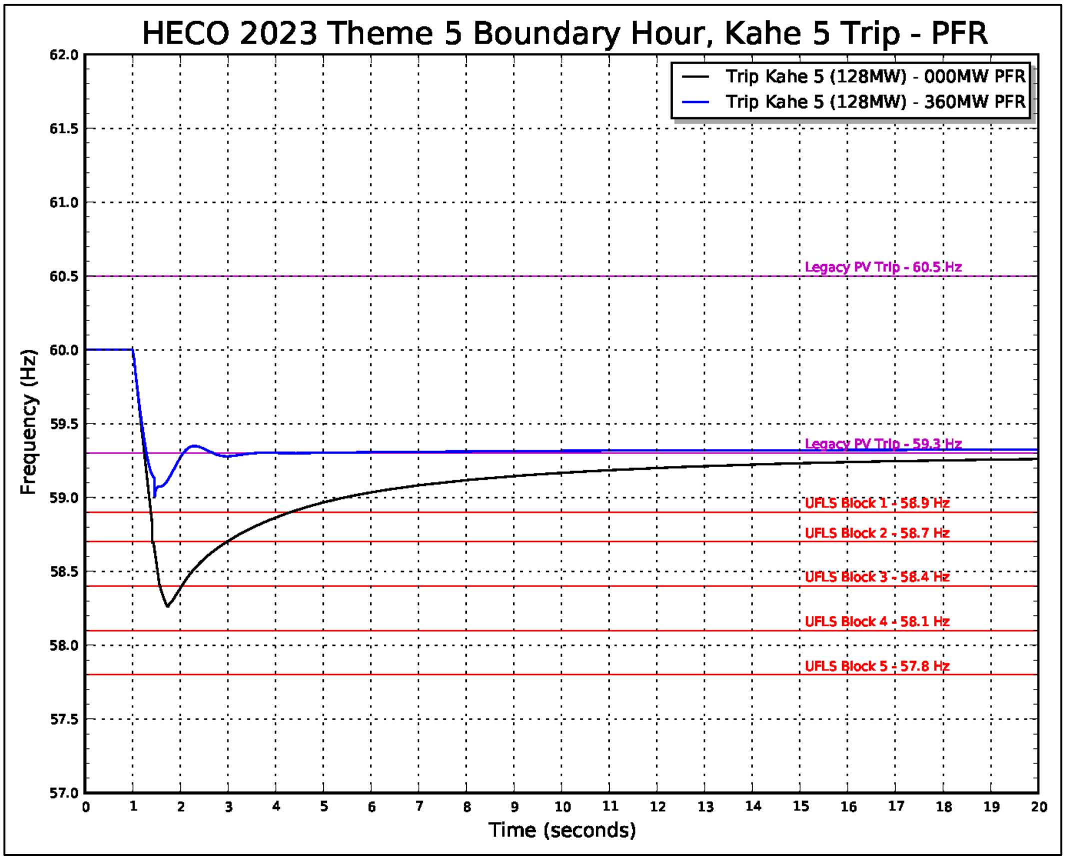

Figure O-92. Frequency Response Profile PFR Boundary Hour

Figure O-92 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 360 MW. This is in addition to the 26 MW of upward regulation from thermal generation.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

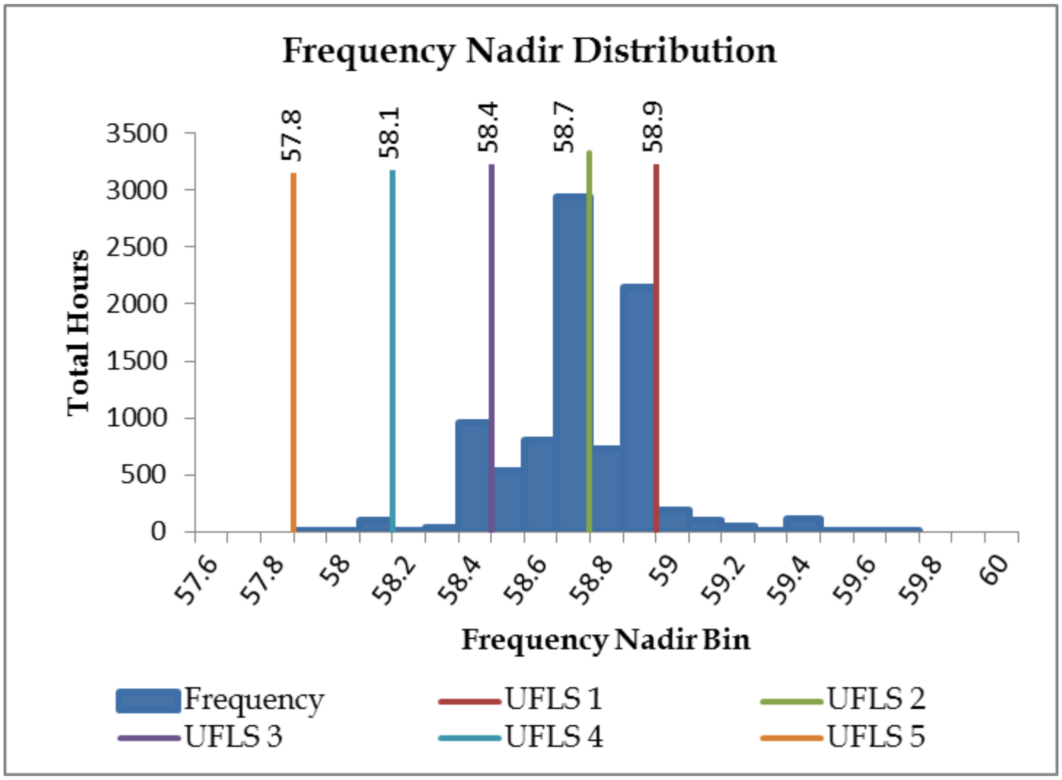

Figure O-93. Frequency Nadir Histogram 2025

Figure O-93 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 952 hours was 10:00 AM on Wednesday, December 24. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 2 hours was 3:00 AM on Sunday, March 16. The frequency nadir range for the boundary hour is 57.8 – 57.9 Hz that requires five blocks of UFLS to stabilize system frequency.

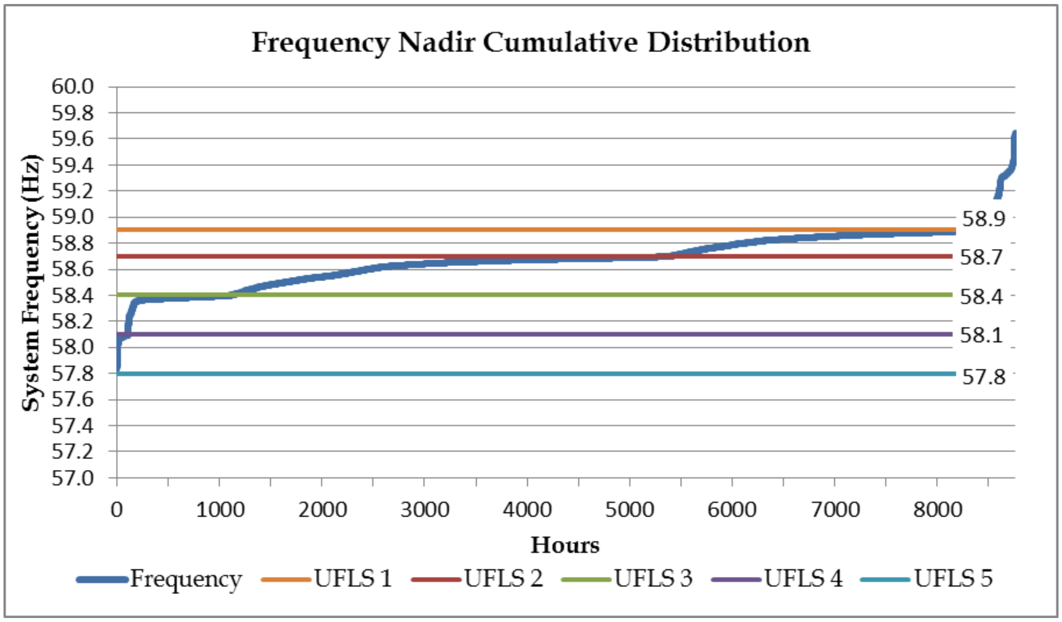

Figure O-94. Frequency Nadir Duration Curve 2025

Figure O-94 shows the frequency nadir duration curve for 2025. The system is at risk of UFLS for 8267 hours of the year.

Unit	Unit Ratings							Theme 5 - GE CT1 Trip Typical Wed 12/24/25 Hour 10			Theme 5 - GE CT1 Trip Boundary Sun 3/16/25 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	82.2	1.8	53.2	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	39.1	0.9	29.1	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	82.2	1.8	53.2	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 2	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 3	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 4	16.8	6.7			0.99	21.8	22				16.8	0.0	10.1
JBPHH 5	16.8	6.7			0.99	21.8	22				13.5	3.3	6.9
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	67.0	0.0	38.0
GE-151CT2	84.0	42.0			3.40	98.5	335						
GE-151ST2	67.0	29.0			4.70	99.3	467						
GE-151CT3	84.0	42.0			3.40	98.5	335						
GE-151ST3	67.0	29.0			4.70	99.3	467						
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	0.0			2.43	11.8	29	0.0	10.0	0.0	0.0	10.0	0.0
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	0.0	0.0			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	0.0	0.0			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Kahe 6	0.0	0.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						44			55		
-Kahuku	30	0						17			12		
-Kawailoa	69	0						19			14		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						2			2		
DG-PV	786	0						227			0		
Station PV	687	0						236			0		
Total Kinetic Energy									3446			3410	
Total Load									930			530	
Total Thermal Generation									423			475	
Total Renewable Generation									507			55	
Total Generation									930			530	
Excess Generation									0			0	
Total Up Regulation									15			24	
Total Down Regulation									249			277	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		22.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		64.8	60.5Hz Output		0.0

Table O-40. Unit Commitment and Dispatch 2025

Table O-40 shows the unit commitment and dispatch for the typical hour 12/24/25, 10:00 AM) and boundary hour (3/16/25, 3:00 AM).

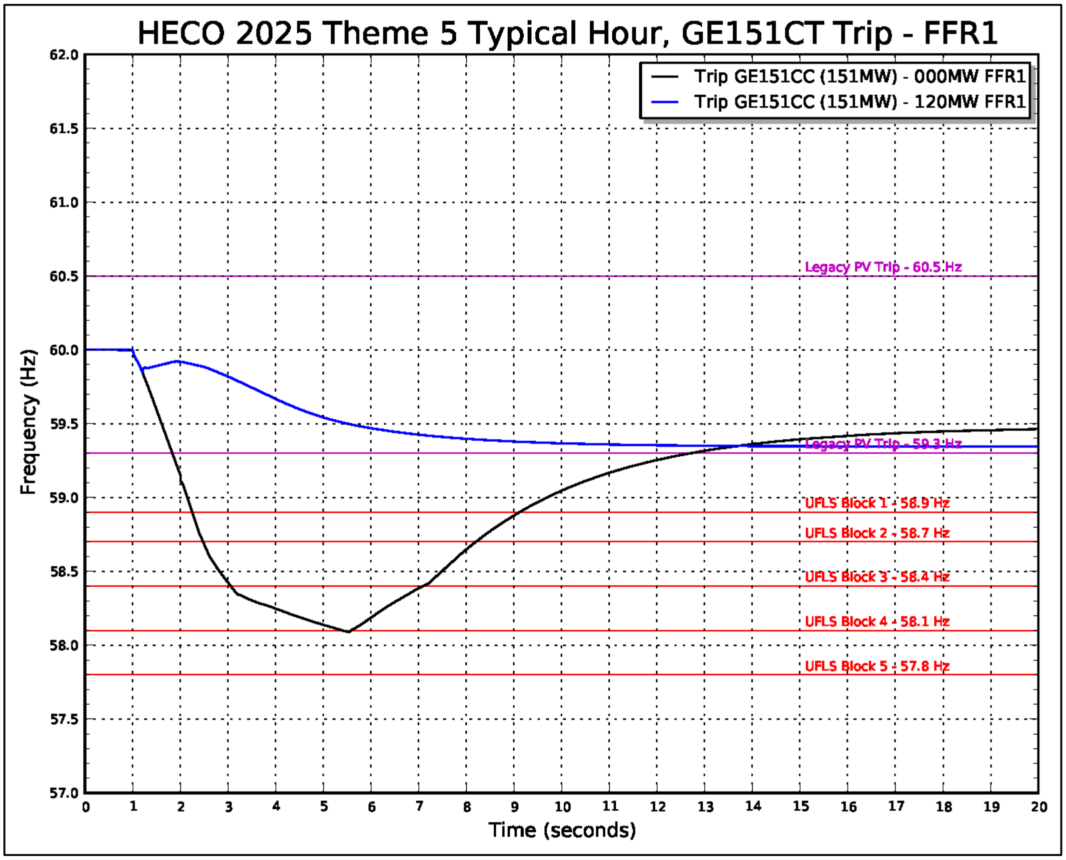

Figure O-95. Frequency Response Profile FFR1 Typical Hour

Figure O-95 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a typical hour. System kinetic energy is 3446 MW-sec and the capacity of legacy PV that will disconnect from the system is 22 MW. With no FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

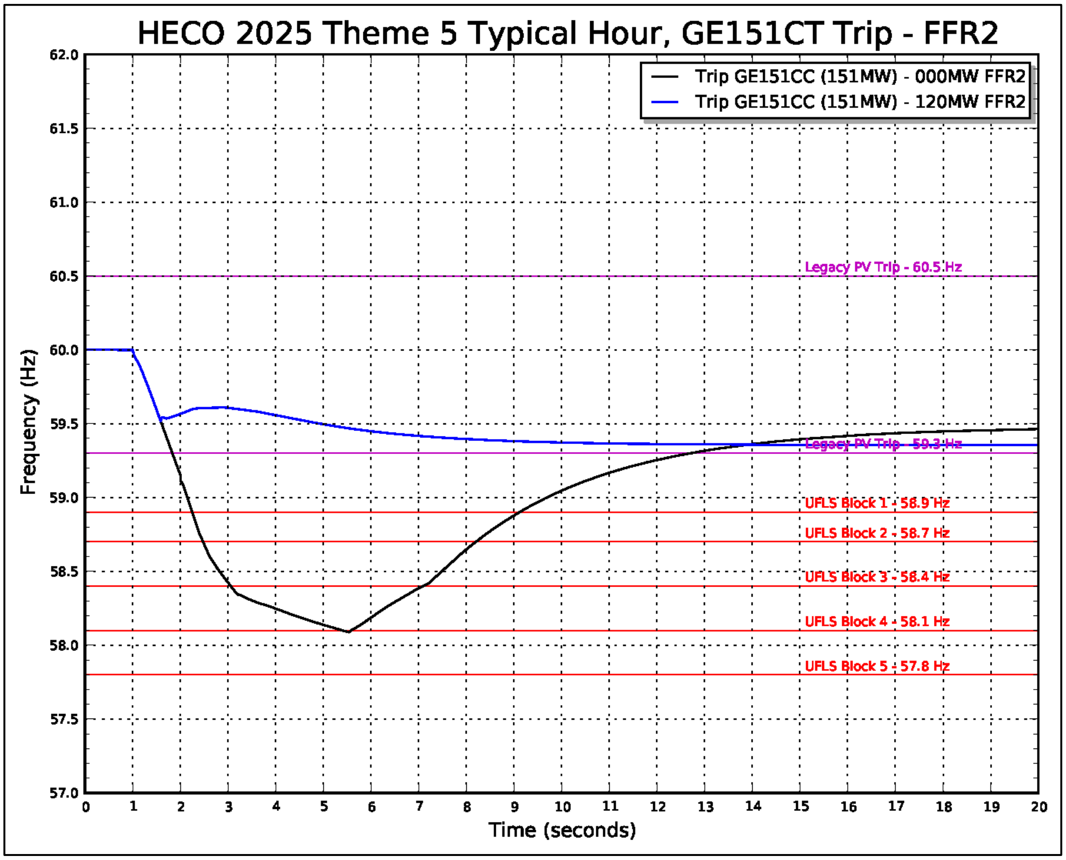

Figure O-96. Frequency Response Profile FFR2 Typical Hour

Figure O-96 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

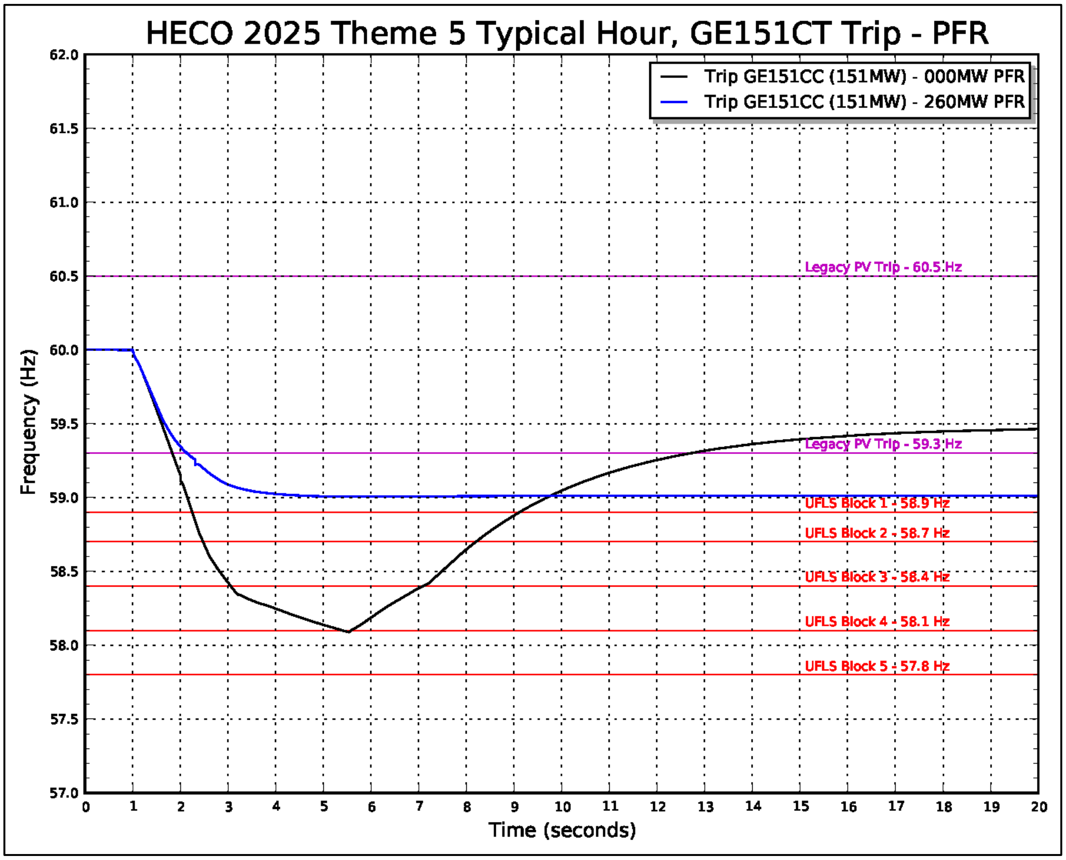

Figure O-97. Frequency Response Profile PFR Typical Hour

Figure O-97 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 15 MW of upward regulation from thermal generation.

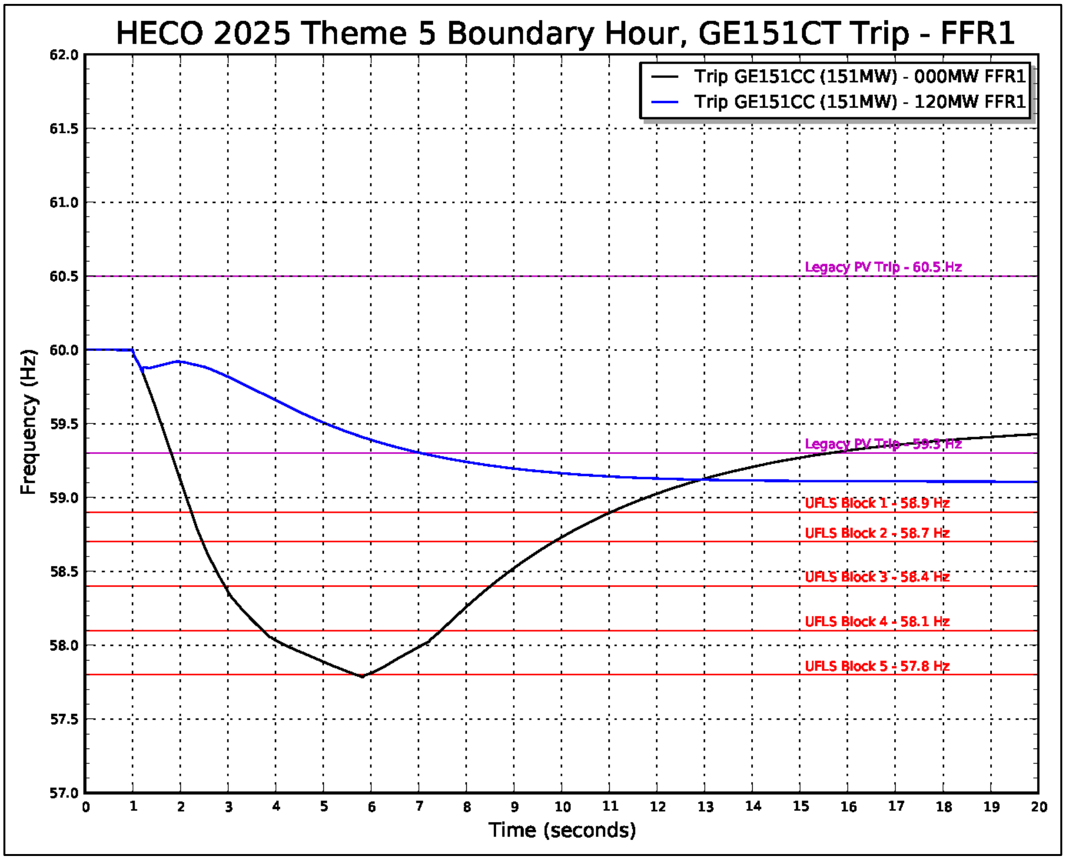

Figure O-98. Frequency Response Profile FFR1 Boundary Hour

Figure O-98 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a boundary hour. System kinetic energy is 3410 MW-sec. With no FFR, the frequency nadir is 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

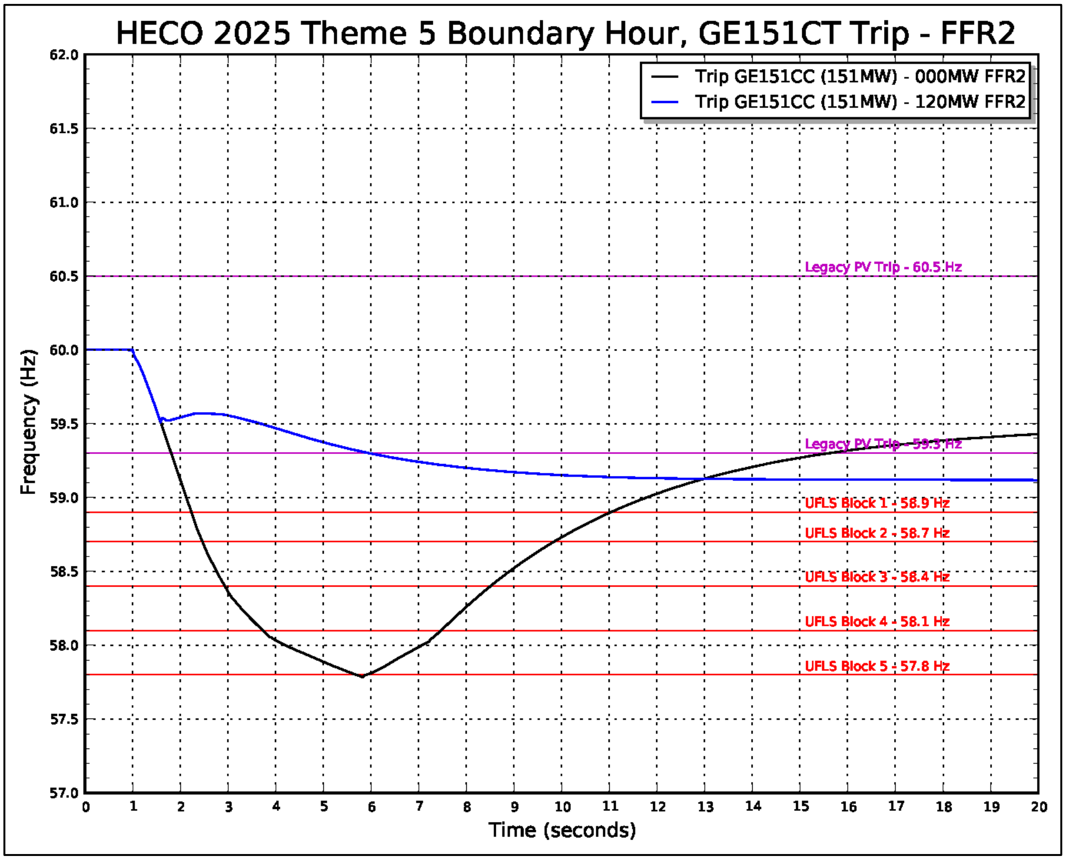

Figure O-99. Frequency Response Profile FFR2 Boundary Hour

Figure O-99 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

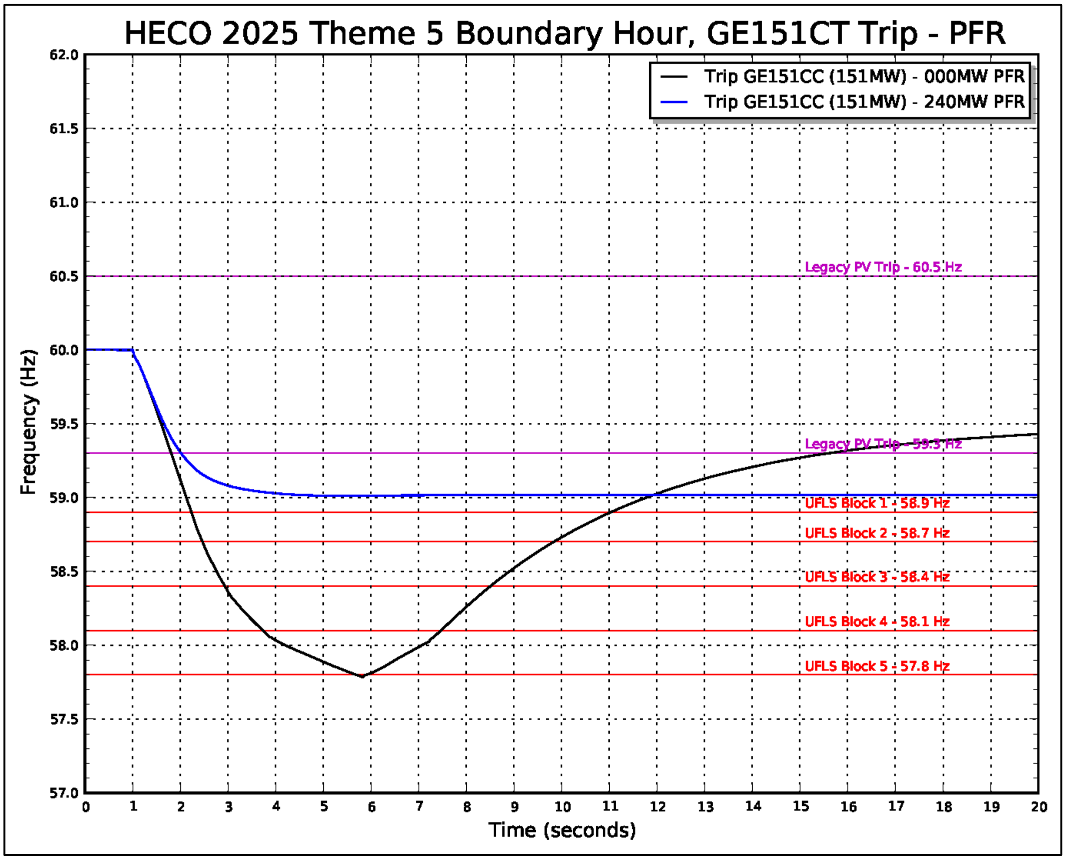

Figure O-100. Frequency Response Profile PFR Boundary Hour

Figure O-100 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 240 MW. This is in addition to the 24 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

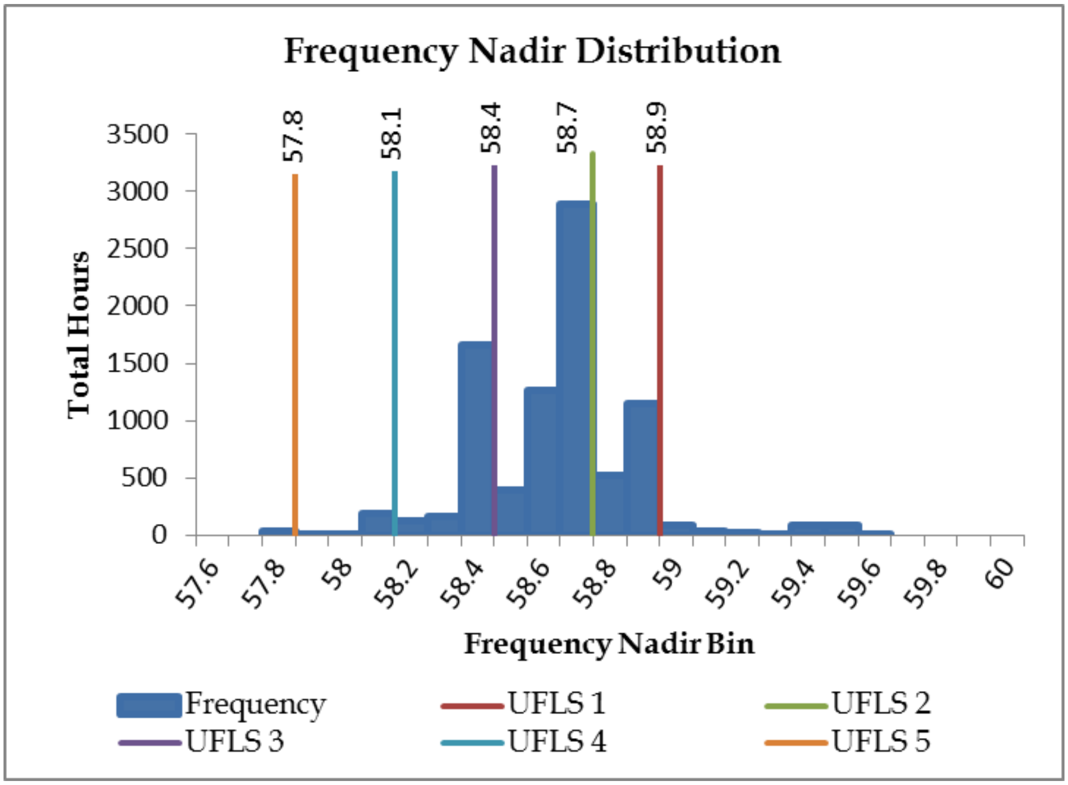

Figure O-101. Frequency Nadir Histogram 2030

Figure O-101 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 1655 hours was 5:00 PM on Tuesday, March 29. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 37 hours was 4:00 AM on Monday, March 4. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

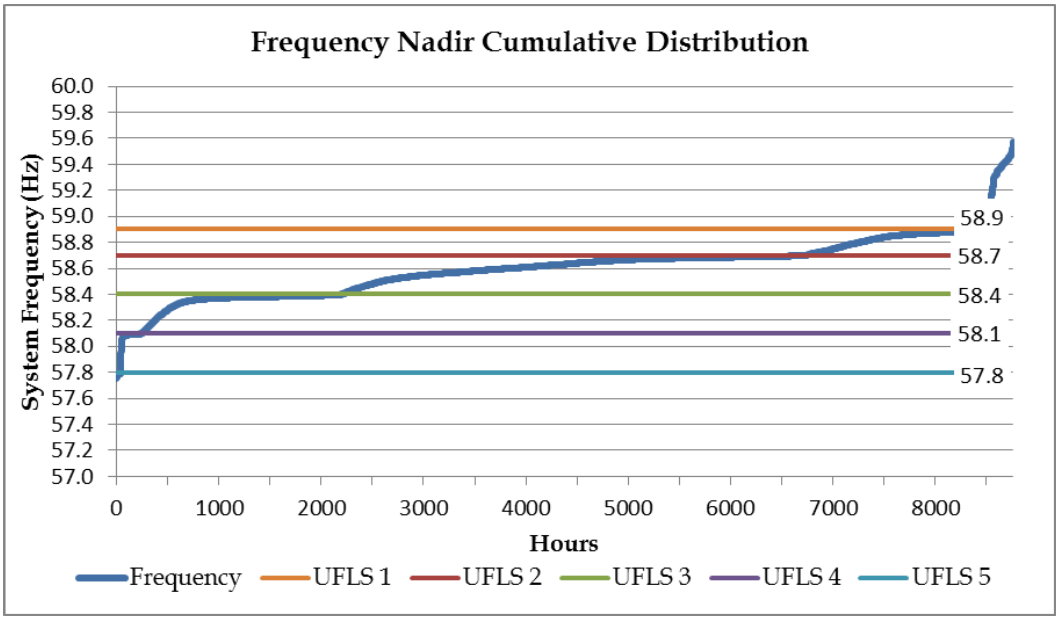

Figure O-102. Frequency Nadir Duration Curve 2030

Figure O-102 shows the frequency nadir duration curve for 2030. The system is at risk of UFLS for 8414 hours of the year.

Unit	Unit Ratings							Theme 5 - GE CT1 Trip Typical Fri 3/29/30 Hour 17			Theme 5 - GE CT1 Trip Boundary Mon 3/4/30 Hour 4		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	67.0	0.0	38.0
GE-151CT2	84.0	42.0			3.40	98.5	335	83.4	0.6	41.4	84.0	0.0	42.0
GE-151ST2	67.0	29.0			4.70	99.3	467	60.7	6.3	31.7	67.0	0.0	38.0
GE-151CT3	84.0	42.0			3.40	98.5	335				83.8	0.2	41.8
GE-151ST3	67.0	29.0			4.70	99.3	467				64.1	2.9	35.1
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	0.0			0.0		
Kahe 6	133.8	40.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						39			18		
-Kahuku	30	0						4			1		
-Kawailoa	69	0						8			9		
-Na Pua Makani	24	0						14			0		
-CBRE Wind	10	0						3			2		
DG-PV	867	0						259			0		
Station PV	847	0						355			0		
Total Kinetic Energy									2777			3435	
Total Load									1016			502	
Total Load Shifting									0			0	
Total Thermal Generation									364			485	
Total Renewable Generation									653			18	
Total Generation									1016			502	
Excess Generation									0			0	
Total Up Regulation									7			14	
Total Down Regulation									187			247	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		22.0	59.3Hz Output		0.0
	60.5Hz Capacity		215.9					60.5Hz Output		64.8	60.5Hz Output		0.0

Table O-41. Unit Commitment and Dispatch 2030

Table O-41 shows the unit commitment and dispatch for the typical hour (3/29/30, 5:00 PM) and boundary hour (3/4/30, 4:00 AM).

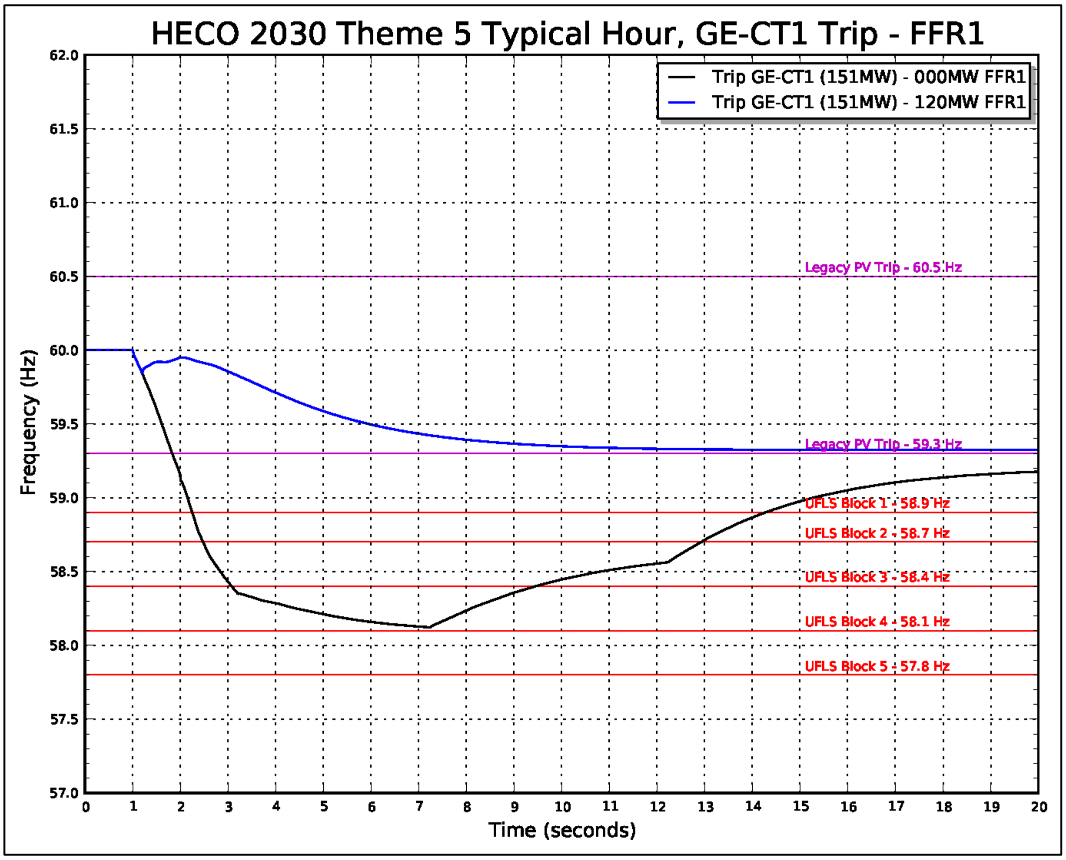

Figure O-103. Frequency Response Profile FFR1 Typical Hour

Figure O-103 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a typical hour. System kinetic energy is 2777 MW-sec and the capacity of legacy PV that will disconnect from the system is 22 MW. With no FFR, the frequency nadir breaches 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW.

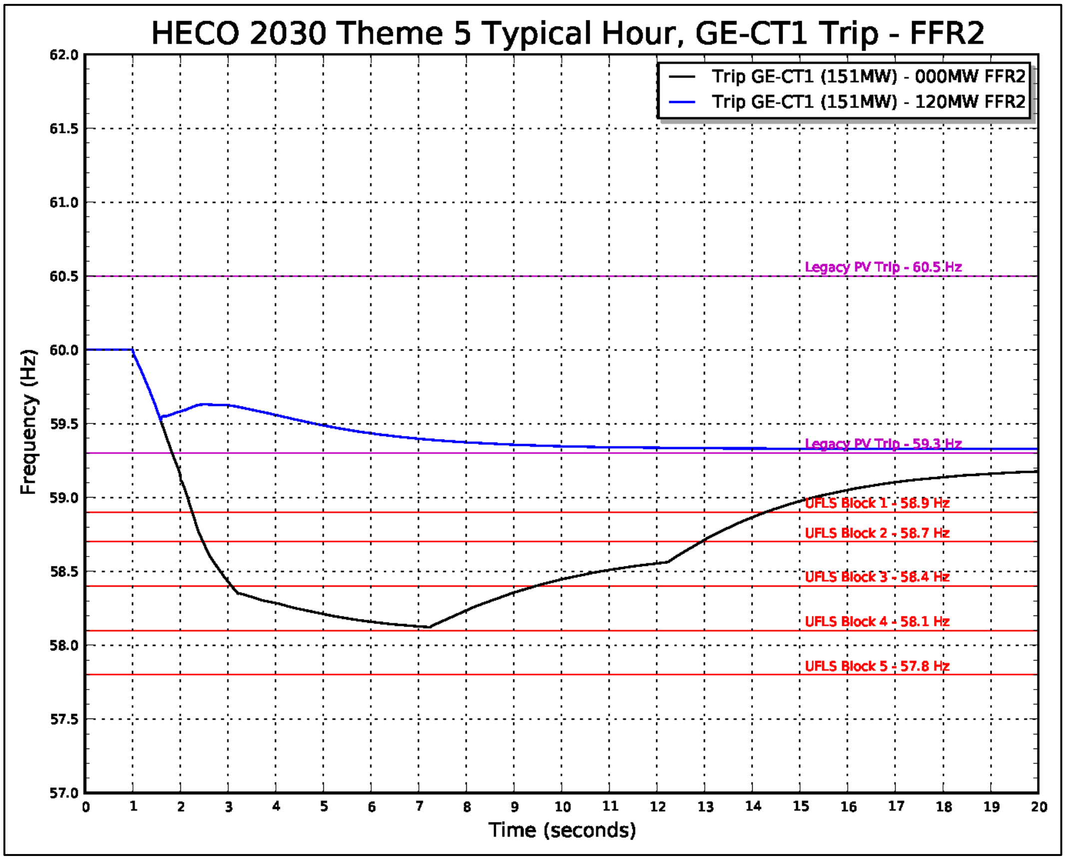

Figure O-104. Frequency Response Profile FFR2 Typical Hour

Figure O-104 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 120 MW.

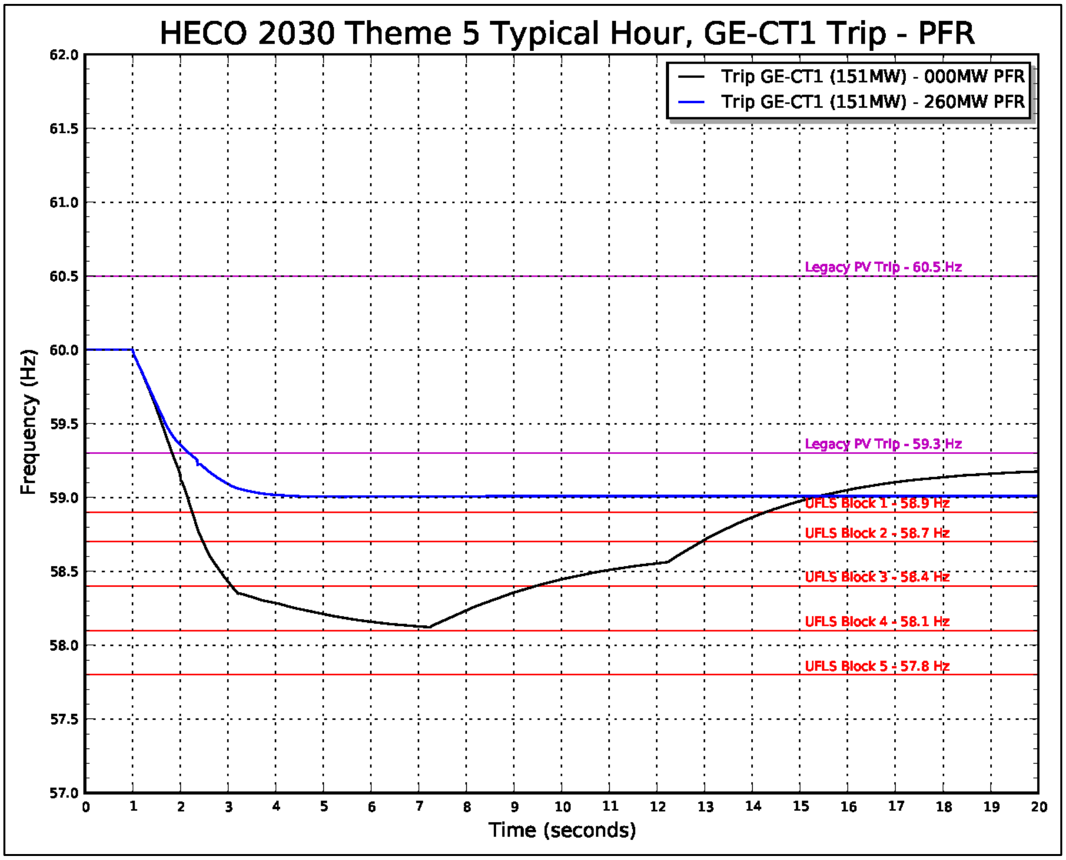

Figure O-105. Frequency Response Profile PFR Typical Hour

Figure O-105 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 7 MW of upward regulation from thermal generation.

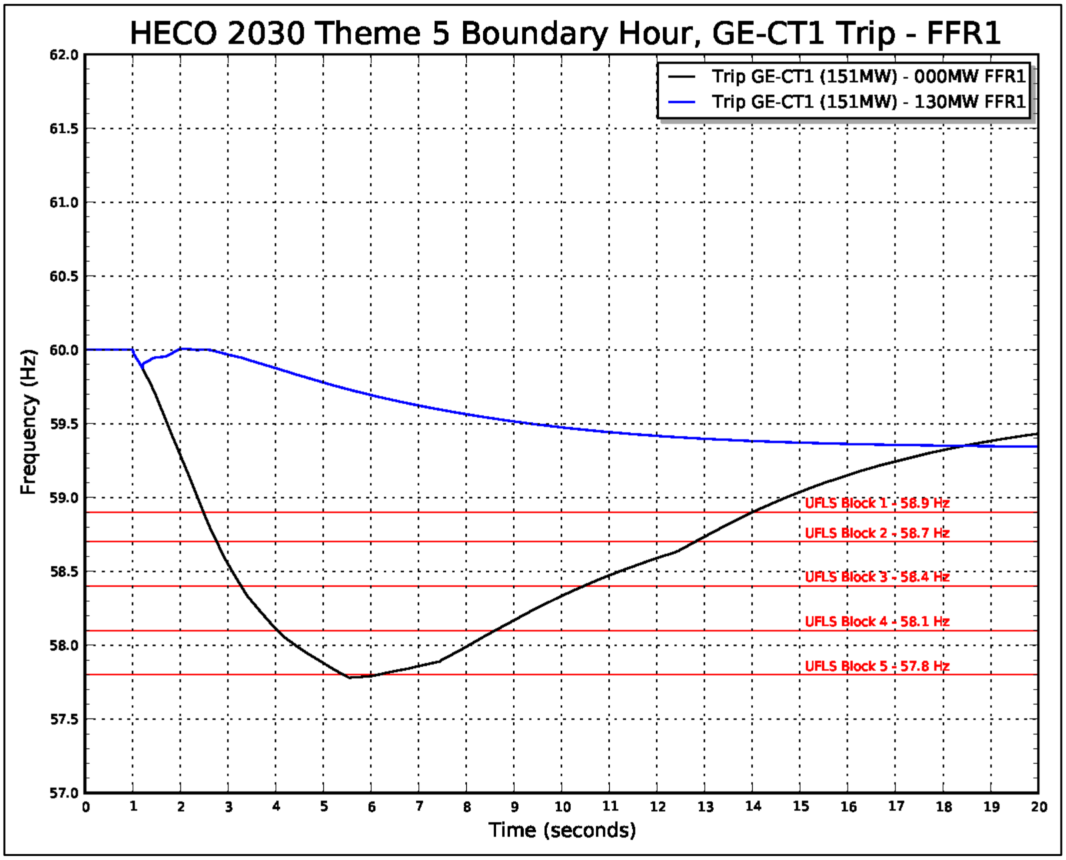

Figure O-106. Frequency Response Profile FFR1 Boundary Hour

Figure O-106 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a boundary hour. System kinetic energy is 3435 MW-sec. With no FFR, the frequency nadir breaches 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 130 MW.

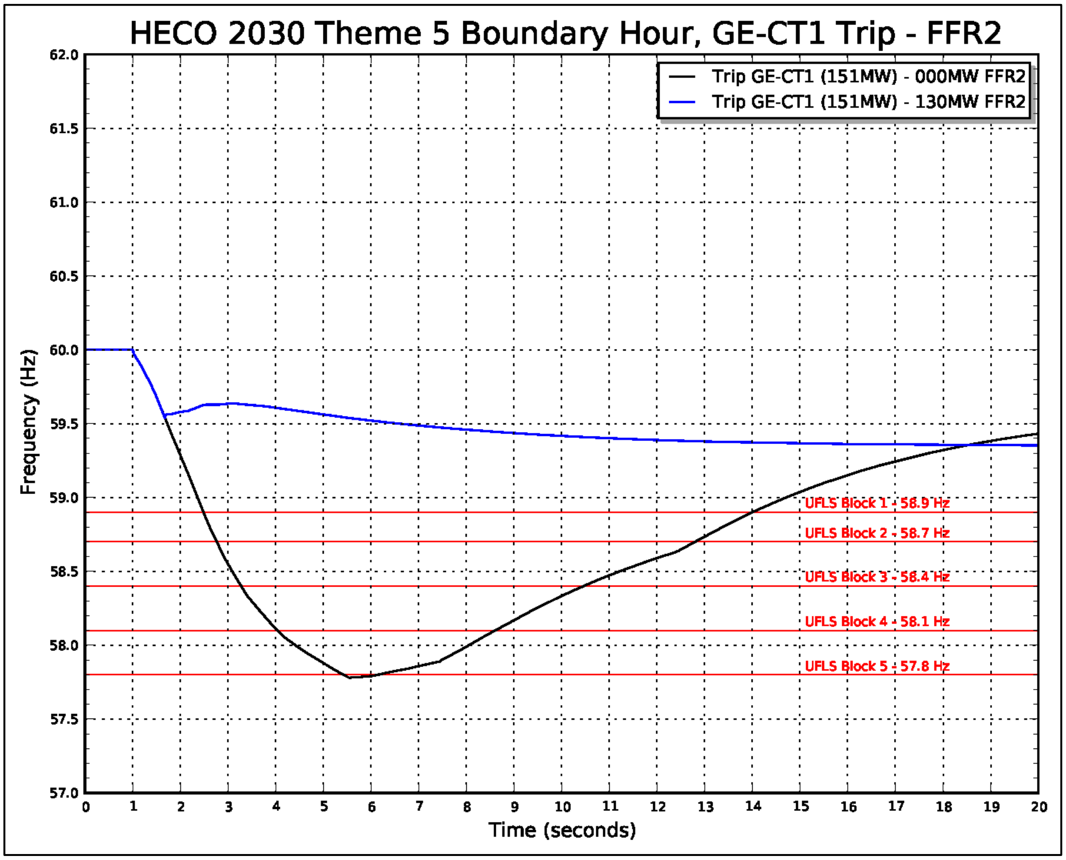

Figure O-107. Frequency Response Profile FFR2 Boundary Hour

Figure O-107 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 130 MW.

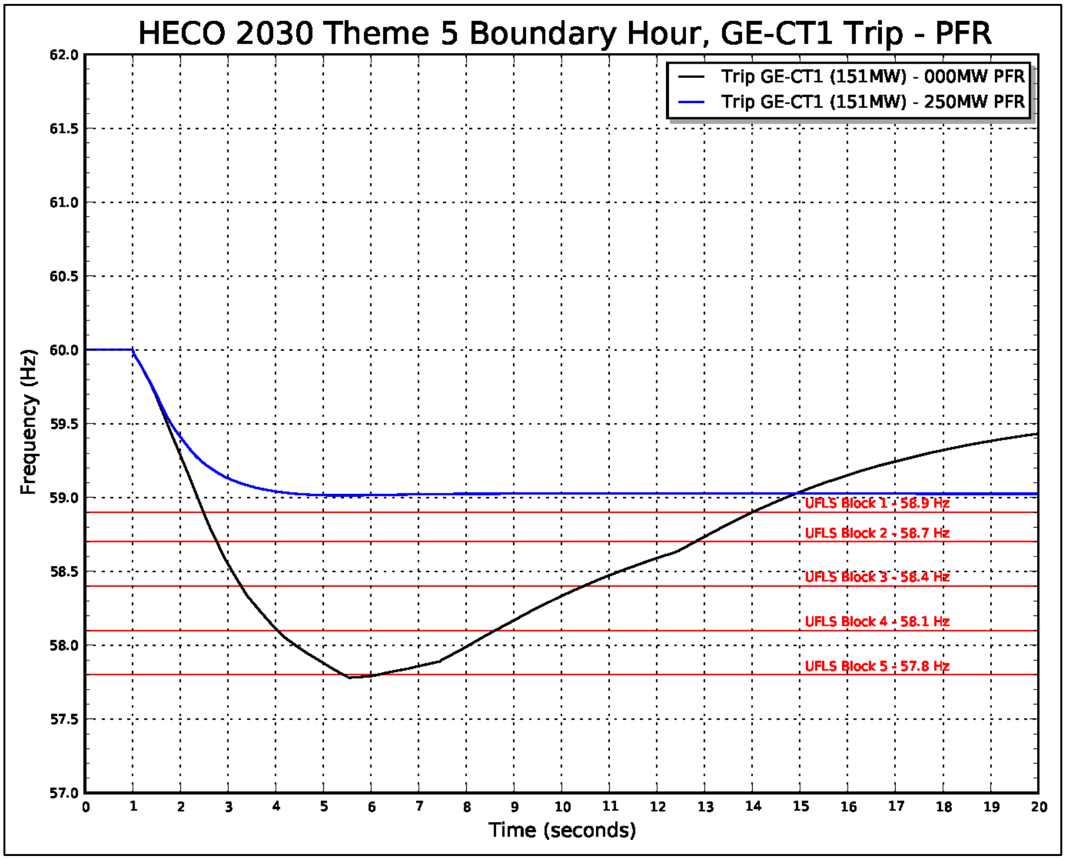

Figure O-108. Frequency Response Profile PFR Boundary Hour

Figure O-108 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 250 MW. This is in addition to the 14 MW of upward regulation in from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

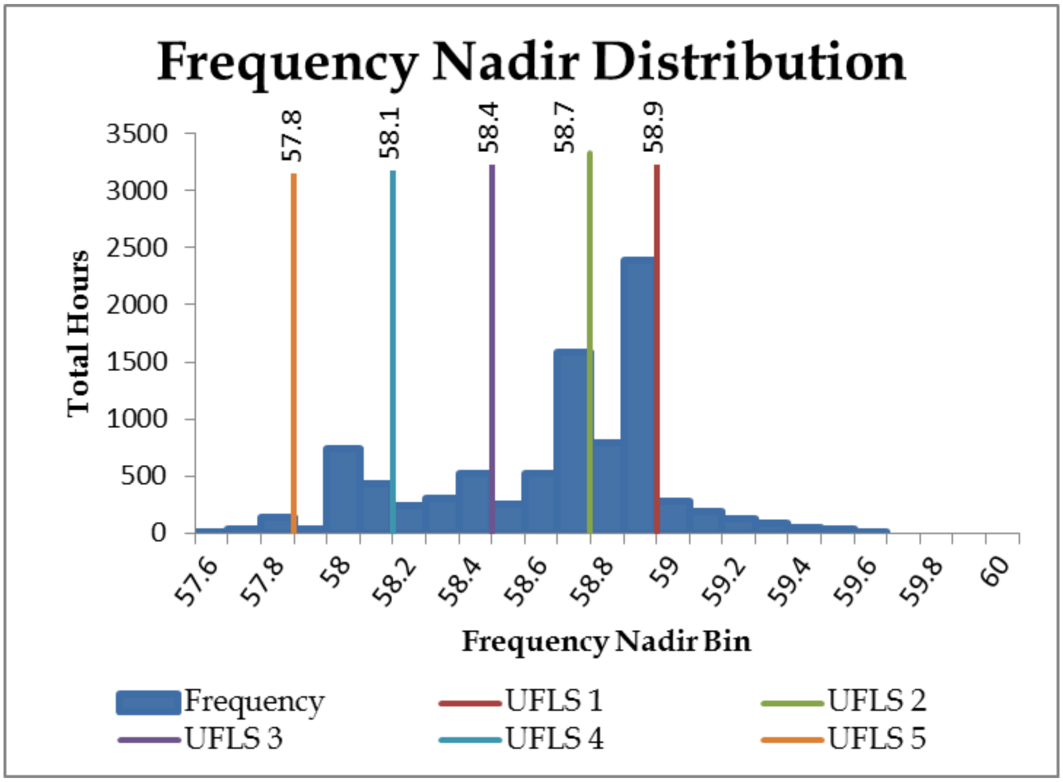

Figure O-109. Frequency Nadir Histogram 2045

Figure O-109 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 5 production cost simulations. The typical hour was selected from the hourly distribution of 737 hours was 2:00 AM on Wednesday, October 4. The frequency nadir range for the typical hour is 57.9- 58.0 Hz that requires four blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 1 hour was 3:00 AM on Friday, January 27. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

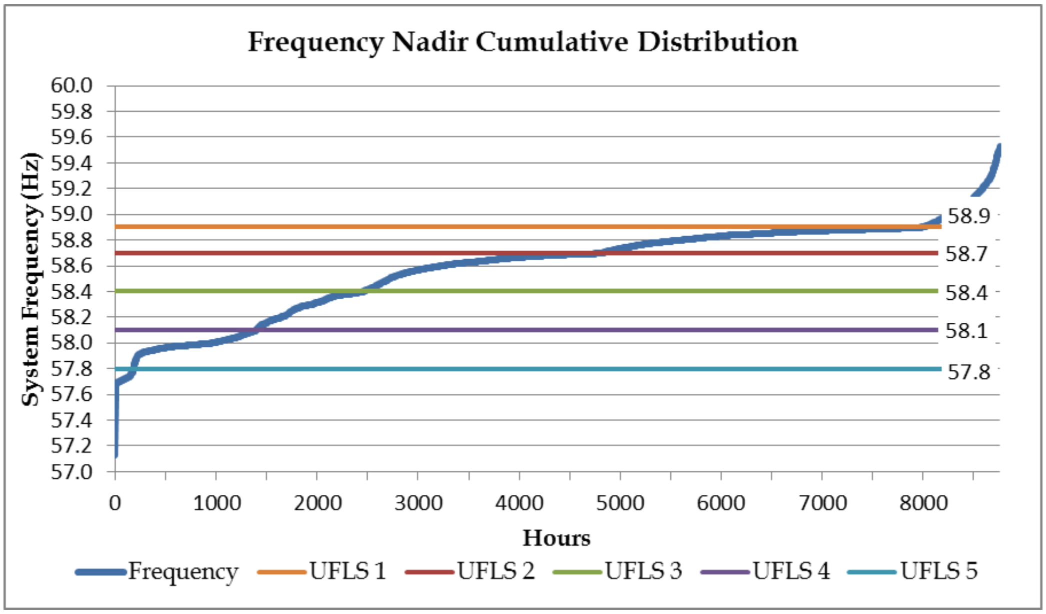

Figure O-110. Frequency Nadir Duration Curve 2045

Figure O-110 shows the frequency nadir duration curve for 2045. The system is at risk of UFLS for 7995 hours of the year.

Unit	Unit Ratings					Theme 5 - Off Shore Wind Trip Typical Wed 10/4/45 Hour 2			Theme 5 - Off Shore Wind TripBoundary Fri 1/27/45 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0	2.78	75.0	209	35.0	11.0	10.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0	3.41	42.1	144						
Kalaeloa CT-1	84.0	29.0	4.96	119.2	591						
Kalaeloa ST	40.0	10.0	4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0	4.96	119.2	591						
Waiau 9	52.9	5.9	7.84	57.0	447						
Waiau 10	49.9	5.9	7.84	57.0	447						
CIP1	112.2	41.2	4.72	162.0	765						
Schofield 1	8.0	2.0	0.99	10.9	11						
Schofield 2	8.0	2.0	0.99	10.9	11						
Schofield 3	8.0	2.0	0.99	10.9	11						
Schofield 4	8.0	2.0	0.99	10.9	11						
Schofield 5	8.0	2.0	0.99	10.9	11						
Schofield 6	8.0	2.0	0.99	10.9	11						
JBPHH 1	16.8	6.7	0.99	21.8	22						
JBPHH 2	16.8	6.7	0.99	21.8	22						
JBPHH 3	16.8	6.7	0.99	21.8	22						
JBPHH 4	16.8	6.7	0.99	21.8	22						
JBPHH 5	16.8	6.7	0.99	21.8	22						
JBPHH 6	16.8	6.7	0.99	21.8	22						
KMCBH 1	9.2	4.6	0.99	10.9	11						
KMCBH 2	9.2	4.6	0.99	10.9	11						
KMCBH 3	9.2	4.6	0.99	10.9	11						
KMCBH 4	9.2	4.6	0.99	10.9	11						
KMCBH 5	9.2	4.6	0.99	10.9	11						
KMCBH 6	9.2	4.6	0.99	10.9	11						
GE-151CT1	84.0	42.0	3.40	98.5	335						
GE-151ST1	67.0	29.0	4.70	99.3	467						
GE-151CT2	84.0	42.0	3.40	98.5	335						
GE-151ST2	67.0	29.0	4.70	99.3	467						
GE-151CT3	84.0	42.0	3.40	98.5	335						
GE-151ST3	67.0	29.0	4.70	99.3	467						
GE-151CT4	84.0	42.0	3.40	98.5	335						
GE-151ST4	67.0	29.0	4.70	99.3	467						
GE-151CT5	84.0	42.0	3.40	98.5	335						
GE-151ST5	67.0	29.0	4.70	99.3	467						
PSH	10.0	-10.0	2.43	11.8	29	-10.0			-10.0		
Kahe 6	133.8	40.0	1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7	2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5	2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0	1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0	1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	963	0				680			683		
-Kahuku	30	0				0			3		
-Kawailoa	69	0				8			17		
-Na Pua Makani	24	0				10			1		
-CBRE Wind	10	0				0			0		
DG-PV	1106	0				0			0		
Station PV	1047	0				0			0		
Total Kinetic Energy							1002			1002	
Total Load							705			508	
Total Load Shifting							0			-200	
Total Thermal Generation							25			25	
Total Renewable Generation							680			683	
Total Generation							705			708	
Excess Generation							0			0	
Total Up Regulation							11			11	
Total Down Regulation							10			10	
Legacy DG-PV	59.3Hz Capacity		0.0			59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity		0.0			60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-42. Unit Commitment and Dispatch 2045

Table O-42 shows the unit commitment and dispatch for the typical hour (10/4/45, 2:00 AM) and boundary hour (1/27/45, 3:00 AM).

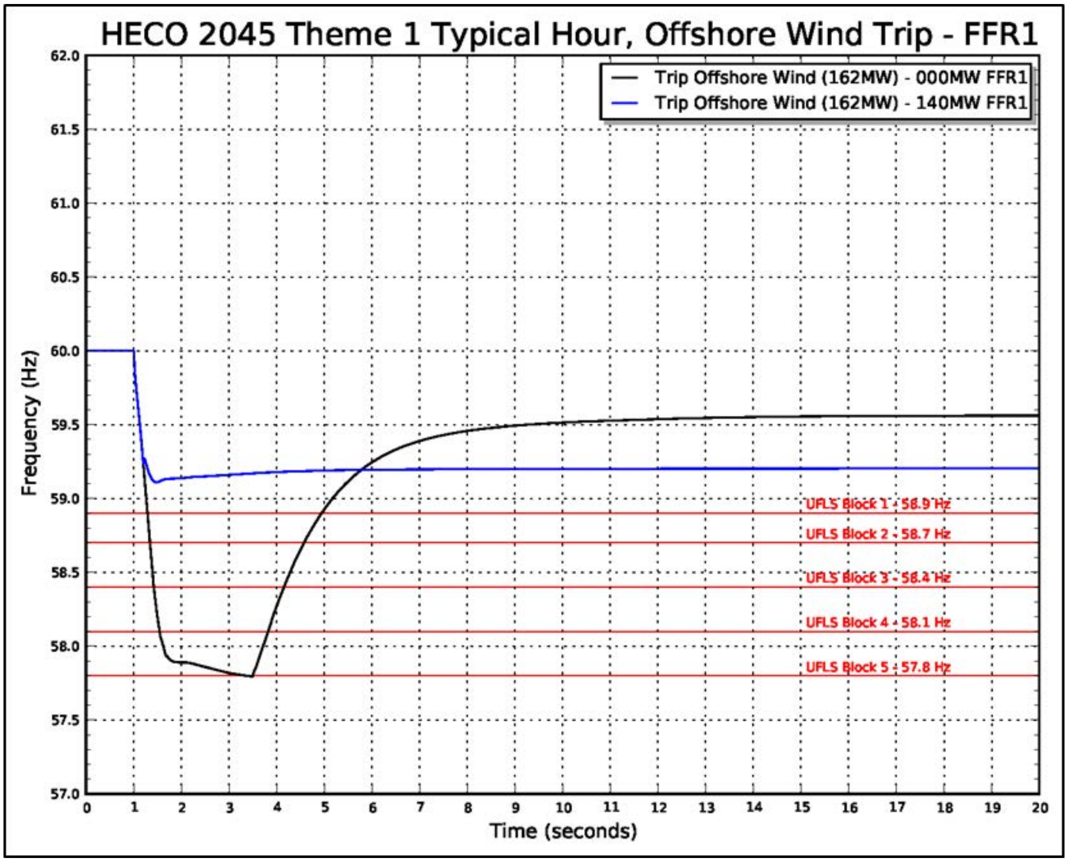

Figure O-111. Frequency Response Profile FFR1 Typical Hour

Figure O-111 shows the frequency response profile for an off-shore wind trip at 162 MW in for a typical hour. System kinetic energy is 1002 MW-sec. With no FFR, the frequency nadir is 57.8 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 140 MW.

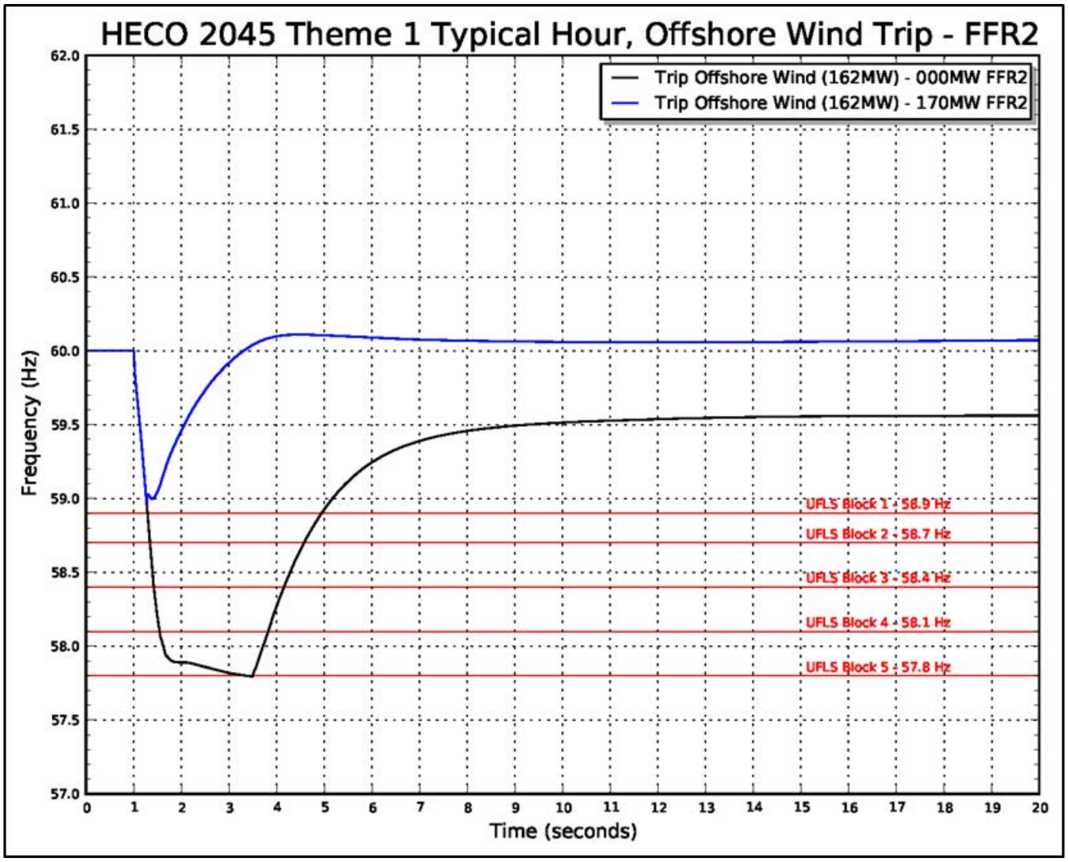

Figure O-112. Frequency Response Profile FFR2 Typical Hour

Figure O-112 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 170 MW.

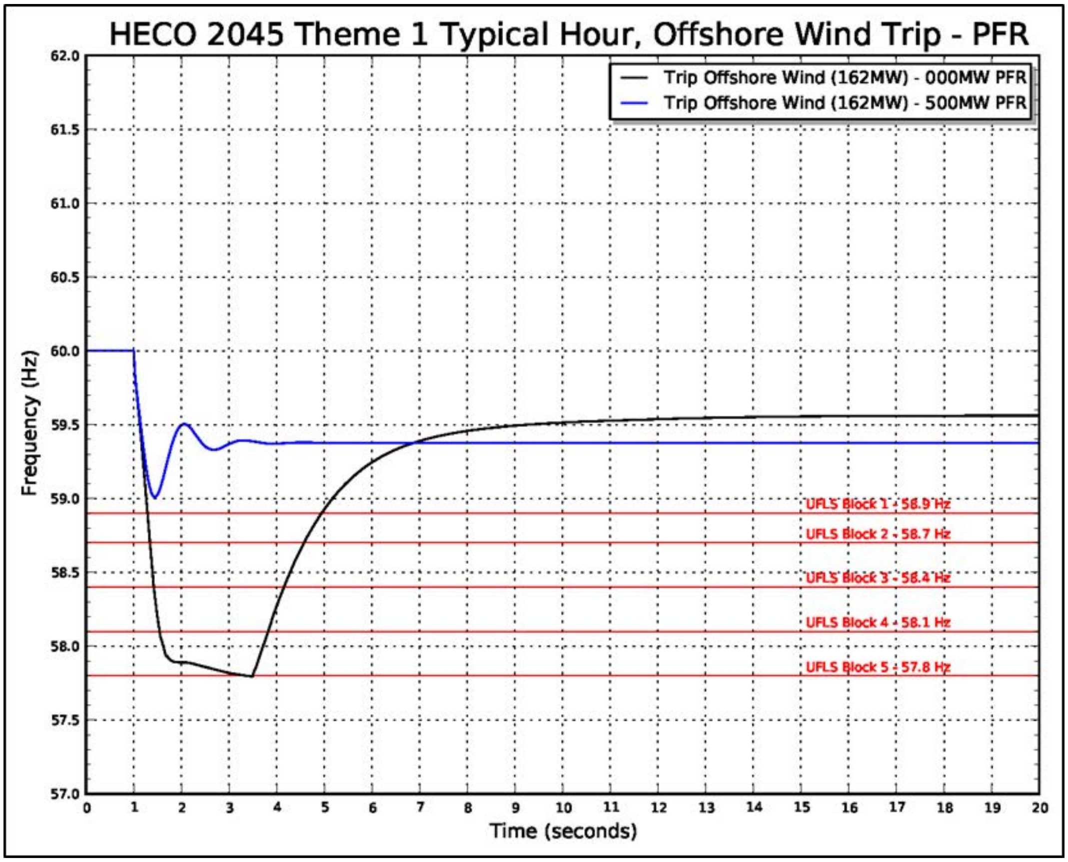

Figure O-113. Frequency Response Profile PFR Typical Hour

Figure O-113 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 500 MW. This is in addition to the 11 MW of upward regulation from thermal generation.

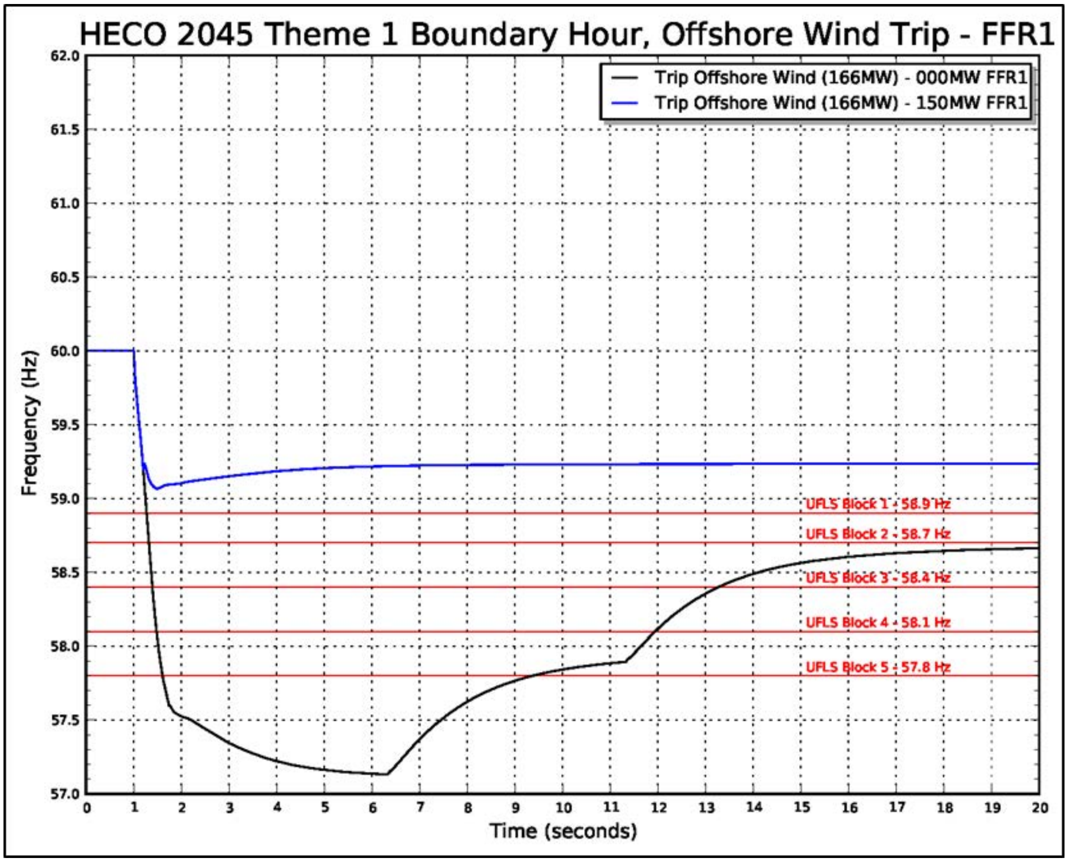

Figure O-114. Frequency Response Profile FFR1 Boundary Hour

Figure O-114 shows the frequency response profile for an off-shore wind trip at 166 MW for a boundary hour. System kinetic energy is 1002 MW-sec. With no FFR, the frequency nadir is 57.2 Hz and five blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 150 MW.

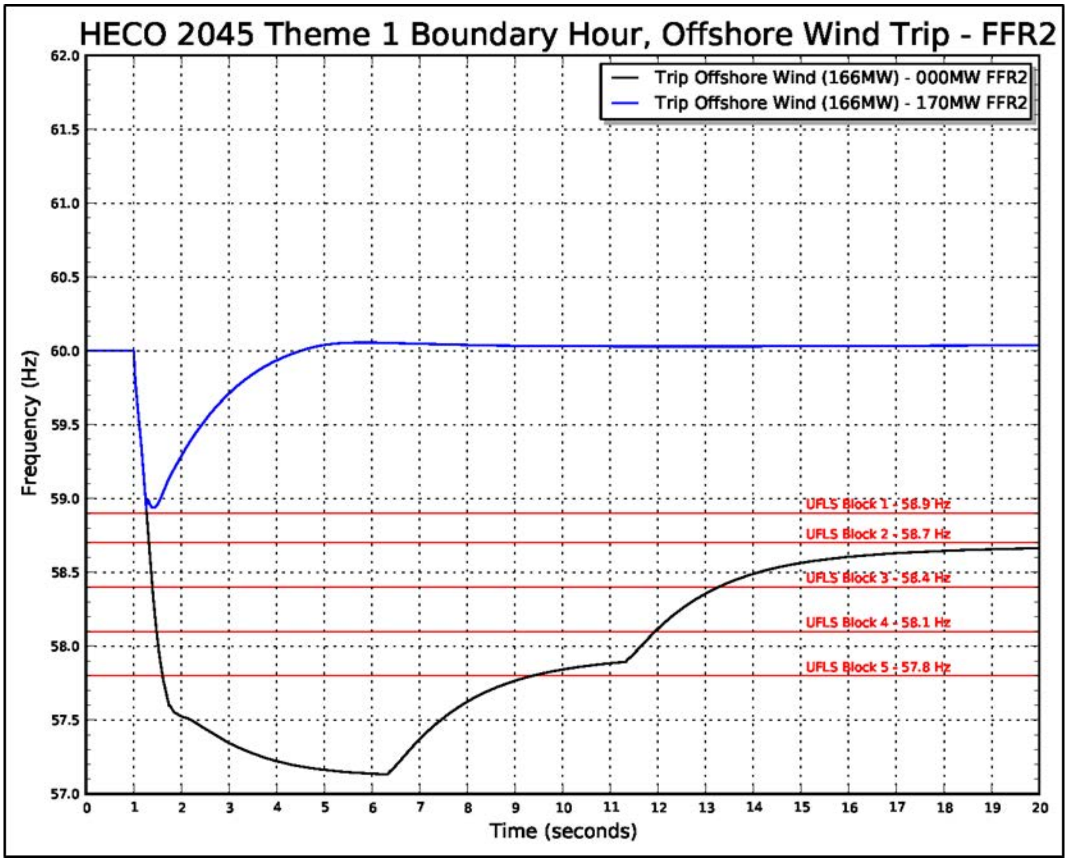

Figure O-115. Frequency Response Profile FFR2 Boundary Hour

Figure O-115 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 170 MW.

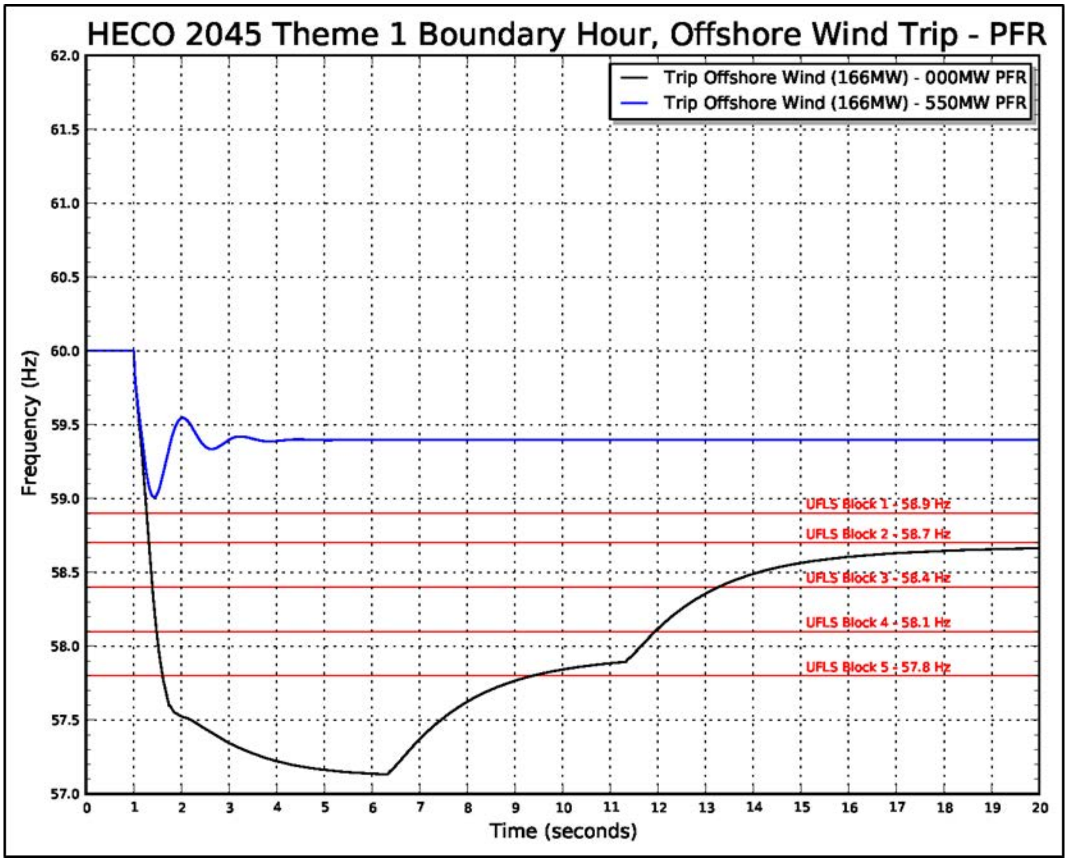

Figure O-116. Frequency Response Profile PFR Boundary Hour

Figure O-116 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 550 MW. This is in addition to the 11 MW of upward regulation from thermal generation.

Post April DR Plan

System security analysis performed on the Post April DR resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O'ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko'olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							DR - QV Dispatch Wed 1/2/2019 Hour 15		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7
AES	189.0	63.0			2.57	239.0	615	188.8	0.2	125.8
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	65.0	19.0	36.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	28.0	12.0	18.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	65.0	19.0	36.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	31.4	50.8	7.6
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	36.2	50.0	12.5
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	35.3	50.0	11.7
Kahe 5	134.6	21.0			4.36	158.8	692	96.9	37.7	75.9
Kahe 6	133.8	40.0			4.36	158.8	692	67.1	66.7	27.1
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	133.0	0.0						28.7		
-Kahuku	30.0	0.0						7.8		
-Kawailoa	69.0	0.0						17.9		
-Na Pua Makani	24.0	0.0								
-CBRE Wind	10.0	0.0						3.0		
-Future Wind	0.0	0.0								
-Offshore Wind	0.0	0.0								
Total Station PV	182.2	0.0						118.2		
-KS2	5.0	0.0						2.9		
-KREP	5.0	0.0						2.3		
-Waianae	27.6	0.0						17.1		
-Kawailoa PV	49.0	0.0						30.0		
-Mililani 2	14.7	0.0						8.0		
-Waiawa	45.9	0.0						30.0		
-Westloch	20.0	0.0						16.1		
-CBRE PV	15.0	0.0						11.8		
-Future PV	0.0	0.0								
DG-PV	654.6	0.0						207.7		
Total Kinetic Energy								4961		
Total Load								1032		
Total Thermal Generation								677		
Total Renewable Generation								355		
Total Generation								1032		
Excess Generation								0		
Total Up Regulation								310		
Total Down Regulation								379		
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		23.3
	60.5Hz Capacity		215.9					60.5Hz Output		68.5

Table O-43. Unit Commitment and Dispatch 2019 QV Analysis

Table O-43 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Wed 1/2/2019 Hour 15		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.8	33.2	-2.8
HPOWER-2	28.0	-16.0	2.8	25.2	-18.8
AES	99.4	-49.8	25.9	73.5	-75.7
Kalaeloa CT-1	84.5	-35.9	13.9	70.6	-49.8
Kalaeloa ST	42.1	-16.7	13.9	28.2	-30.6
Kalaeloa CT-2	84.5	-35.8	13.9	70.6	-49.7
Kahe 1	67.0	-51.2	17.4	49.6	-68.6
Kahe 2	64.4	-50.3			
Kahe 3	71.2	-21.3	17.4	53.8	-38.6
Kahe 4	63.8	-20.5	17.4	46.4	-37.9
Kahe 5	96.6	-63.4	79.1	17.5	-142.4
Kahe 6	107.7	-61.9	38.5	69.3	-100.4
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	87.4	-110.9	6.4	64.6	-101.9
-Kahuku	17.9	-17.9	3.7	14.2	-21.6
-Kawailoa	50.0	-74.5	2.7	47.3	-77.2
-Na Pua Makani	16.4	-15.4			
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	0.0	0.0			
-Offshore Wind	0.0	0.0			
Total Station PV	109.4	-109.4	5.2	104.2	-114.6
-KS2	1.6	-1.6	-0.1	1.7	-1.5
-KREP	2.0	-2.0	1.5	0.5	-3.5
-Waianae	14.5	-14.5	1.1	13.4	-15.6
-Kawailoa PV	36.8	-36.8	-0.5	37.3	-36.2
-Mililani 2	10.7	-10.7	-0.4	11.1	-10.3
-Waiawa	32.9	-32.9	1.1	31.8	-34.0
-Westloch	6.3	-6.3	2.4	3.8	-8.7
-CBRE PV	4.7	-4.7	0.1	4.6	-4.7
-Future PV	0.0	0.0			
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			242.9		
Total Renewable MVAR Generation			11.6		
Total Cap Bank MVAR			186.1		
Charging MVAR			77.4		
Total MVAR Supply			518.1		
Total MVAR Load			336.2		
Total MVAR Losses			181.9		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				706.5	
Total MVAR Absorb Capability					-832.0

Table O-44. MVAR Capability 2019 QV Analysis

Table O-44 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1

Table O-45. N-2 Contingencies 2019 QV Analysis

Table O-45 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

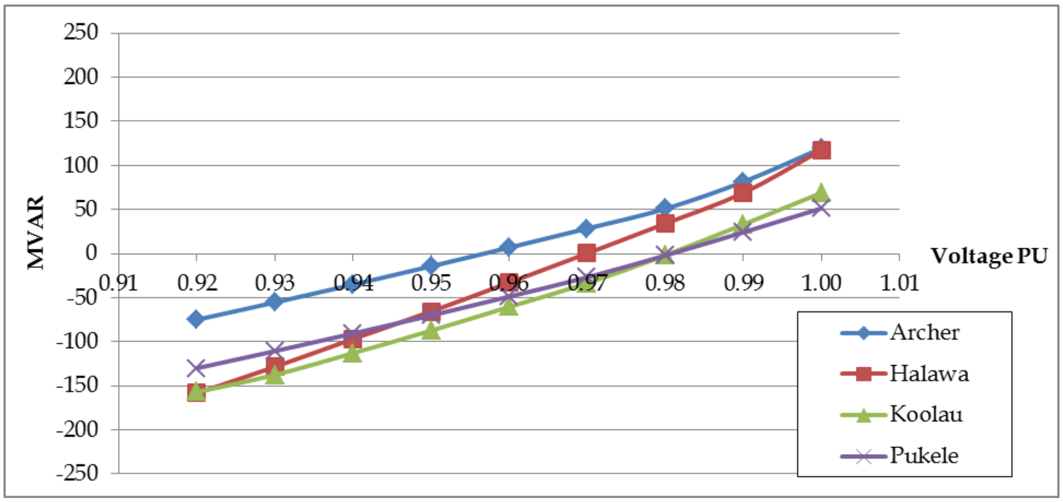

Figure O-117. QV Curves 2019

Figure O-117 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. The unit commitment and dispatch meets the reactive power requirements of the system under N-2 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	120	125	82	135	51	135	29	135	7	135	-14	135	-35	135	-55	135	-75
120	Halawa	125	118	154	69	154	34	154	0	154	-33	154	-66	154	-97	154	-128	154	-158
150	Koolau	125	69	125	33	125	-2	125	-33	125	-60	125	-87	125	-113	125	-138	203	-157
170	Pukele	125	51	125	24	125	-2	125	-27	125	-49	125	-70	125	-91	125	-111	125	-130

Table O-46. Summary of Results 2019 QV Analysis

Table O-46 shows the results of the 2019 QV analysis. The unit commitment and dispatch is able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

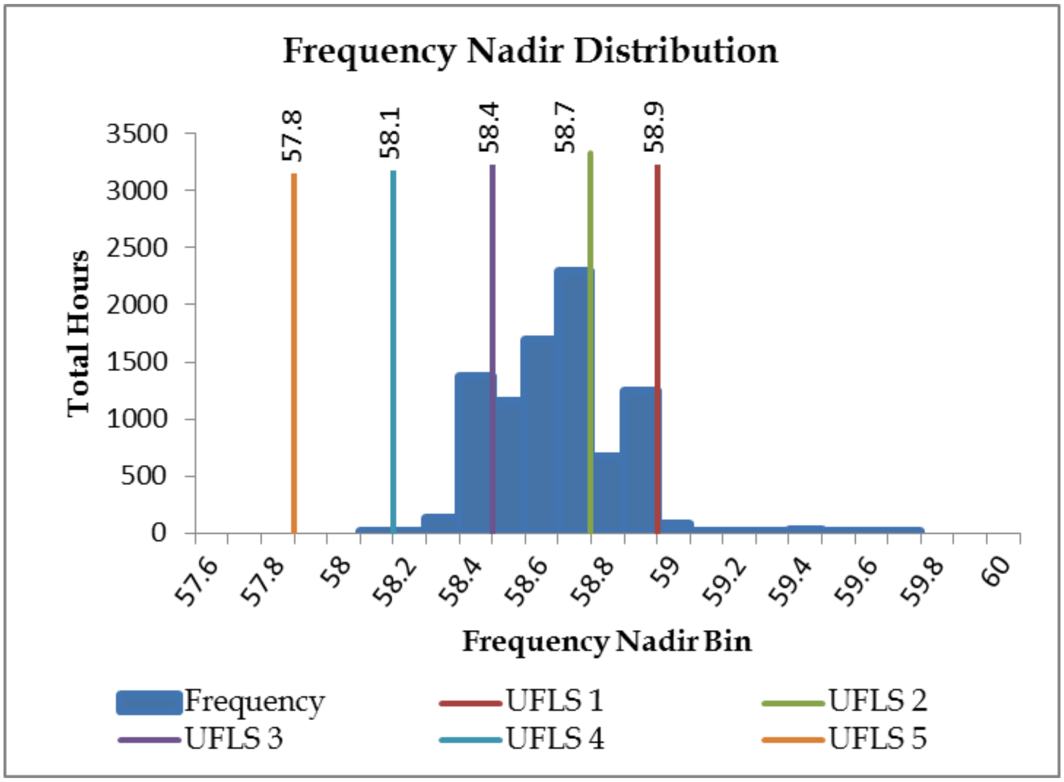

Figure O-118. Frequency Nadir Histogram 2019

Figure O-118 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1370 hours was 2:00 PM on Thursday, March 21. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 3 hours was 3:00 AM on Tuesday, March 19. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

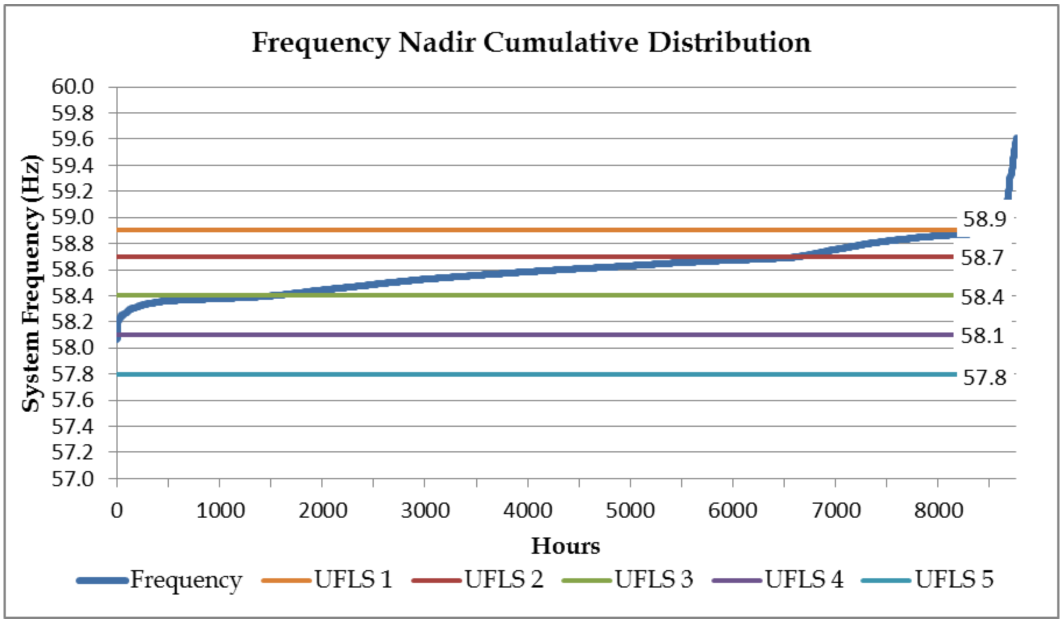

Figure O-119. Frequency Nadir Duration Curve 2019

Figure O-119 shows the frequency nadir duration curve for 2019. The system is at risk of UFLS for 8575 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Thu 3/21/19 Hour 14			DR - AES Trip Boundary Tue 3/19/19 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	55.8	28.2	26.8	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	13.3	6.7	3.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	41.6	40.6	17.8
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	31.8	54.4	8.1	38.0	48.2	14.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261	25.0	29.5	1.5			
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	25.6	57.7	1.8			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	133	0						34			49		
-Kahuku	30	0						6			23		
-Kawailoa	69	0						14			16		
-Na Pua Makani	24	0						12			7		
-CBRE Wind	10	0						2			2		
DG-PV	655	0						437			0		
Station PV	183	0						160			0		
Total Kinetic Energy									4098			3502	
Total Load									1111			585	
Total Thermal Generation									479			537	
Total Renewable Generation									632			49	
Total Generation									1111			585	
Excess Generation									0			0	
Total Up Regulation									356			157	
Total Down Regulation									200			309	
Total FFR2 Capacity									47			26	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		48.4	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		142.3	60.5Hz Output		0.0

Table O-47. Unit Commitment and Dispatch 2019

Table O-47 shows the unit commitment and dispatch for the typical hour (3/21/19, 2:00 PM) and boundary hour (3/19/19, 3:00 AM).

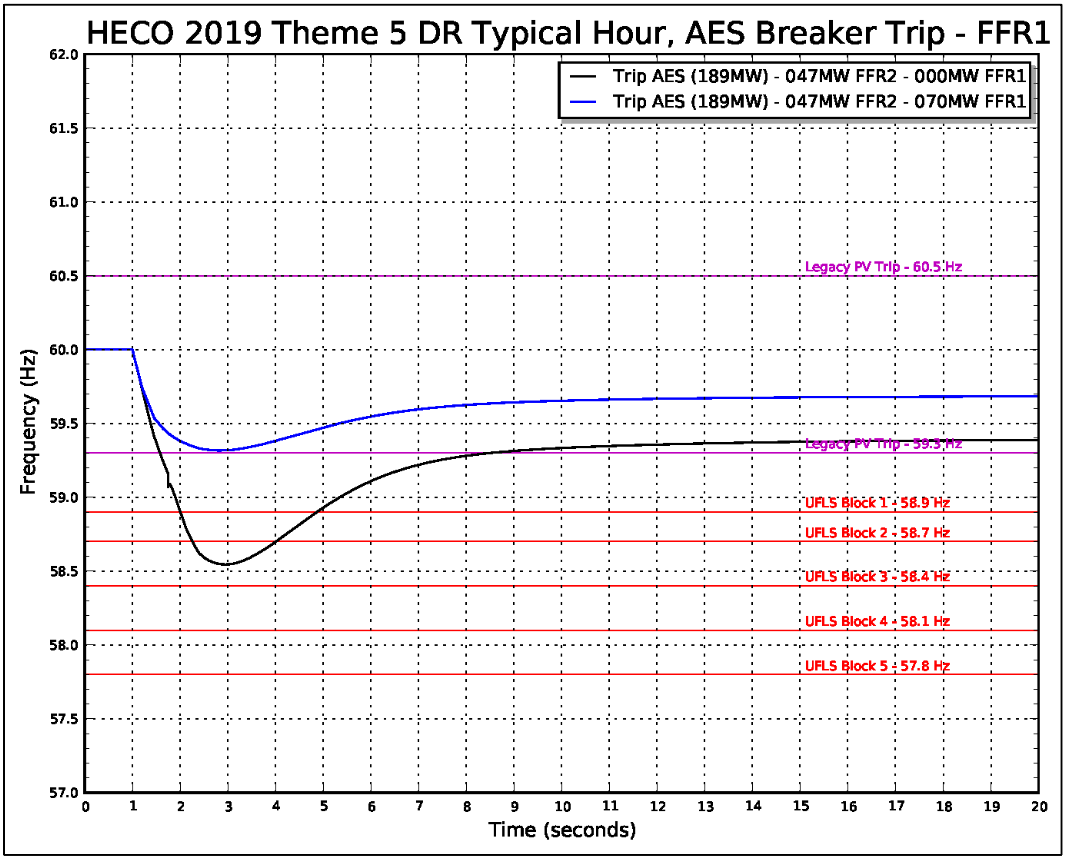

Figure O-120. Frequency Response Profile FFR1 Typical Hour

Figure O-120 shows the frequency response profile for an AES Trip at 189 MW for a typical hour. System kinetic energy is 4098MW-sec, the capacity of legacy PV that will disconnect from the system is 48.4 MW, and the capacity of FFR2 is 47 MW. With no FFR1, the frequency nadir breaches 58.6 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 47 MW of FFR2.

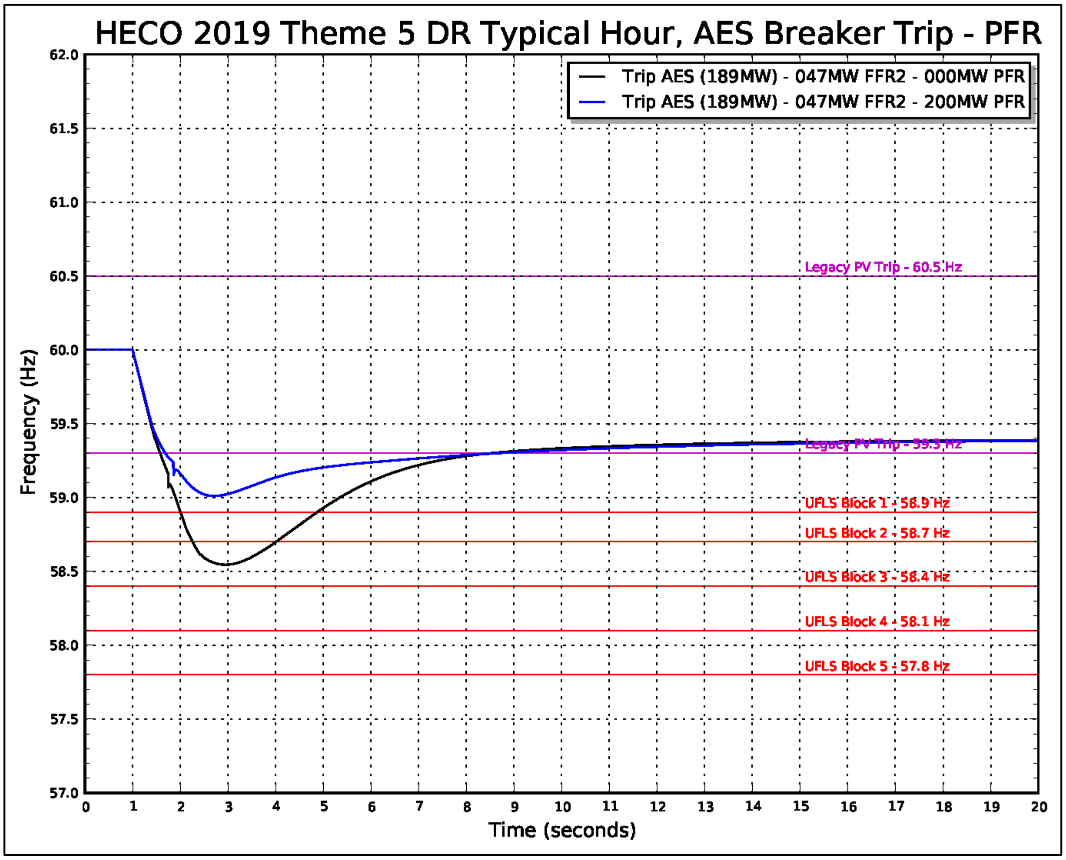

Figure O-121. Frequency Response Profile PFR Typical Hour

Figure O-121 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 47 MW of FFR2 and 356 MW of upward regulation from thermal generation.

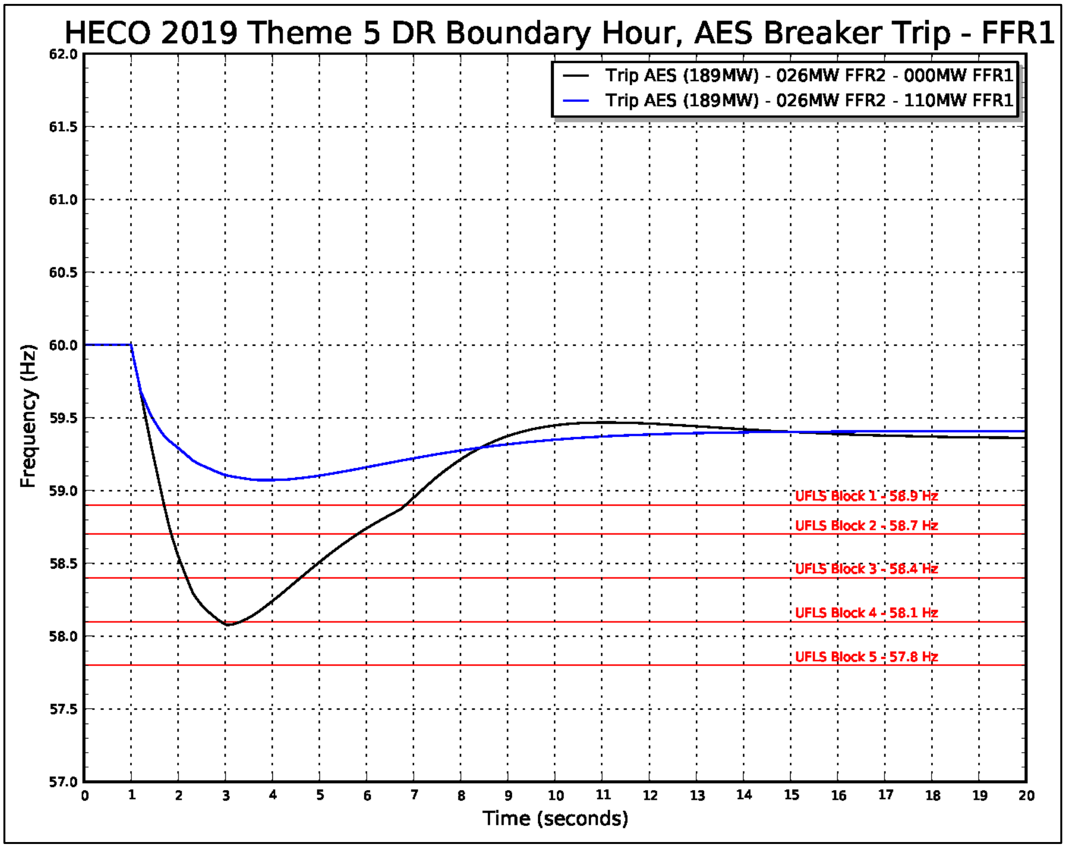

Figure O-122. Frequency Response Profile FFR1 Boundary Hour

Figure O-122 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3502 MW-sec and the capacity of FFR2 is 26 MW. With no FFR1, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 110 MW. This is in addition to the 26 MW of FFR2.

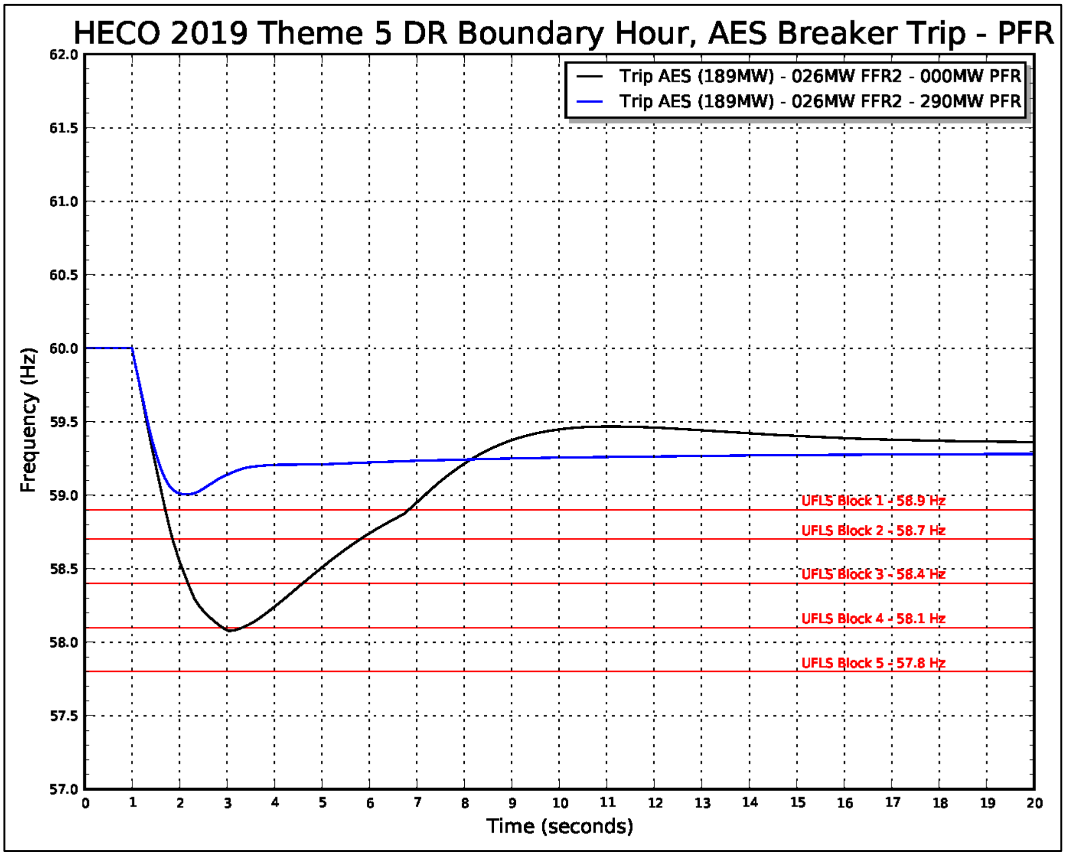

Figure O-123. Frequency Response Profile PFR Boundary Hour

Figure O-123 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 290 MW. This is in addition to the 26 MW of FFR2 and 157 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip typical Thu 3/21/19 Hour 14			DR - K5 Trip Boundary Tue 3/19/19 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.7	4.8	7.7			
AES	189.0	63.0			2.57	239.0	615	105.0	84.0	42.0	134.0	55.0	71.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	55.8	28.2	26.8	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	13.3	26.7	3.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	31.8	54.4	8.1			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	133	0						34			49		
-Kahuku	30	0						6			23		
-Kawailoa	69	0						14			16		
-Na Pua Makani	24	0						12			7		
-CBRE Wind	10	0						2			2		
DG-PV	655	0						437			0		
Station PV	183	0						160			0		
Total Kinetic Energy									4104			3411	
Total Load									1111			585	
Total Thermal Generation									479			537	
Total Renewable Generation									632			49	
Total Generation									1111			585	
Excess Generation									0			0	
Total Up Regulation									373			123	
Total Down Regulation									226			336	
Total FFR2 Capacity									47			26	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		48.4	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		142.3	60.5Hz Output		0.0

Table O-48. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-48 shows the unit commitment and dispatch for the typical hour (3/21/19, 2:00 PM) and boundary hour (3/19/19, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

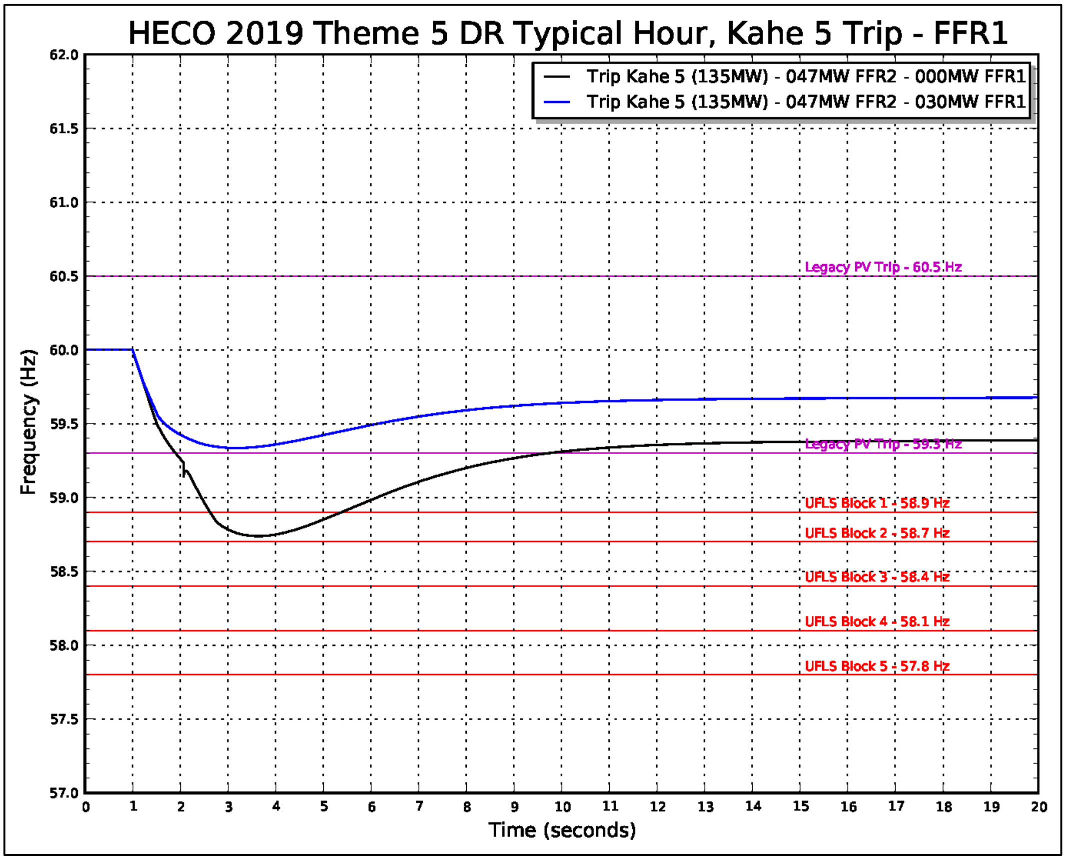

Figure O-124. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-124 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4104 MW-sec, the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 48.4 MW, and the capacity of FFR2 is 47 MW. With no FFR1, the frequency nadir breaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 30 MW.

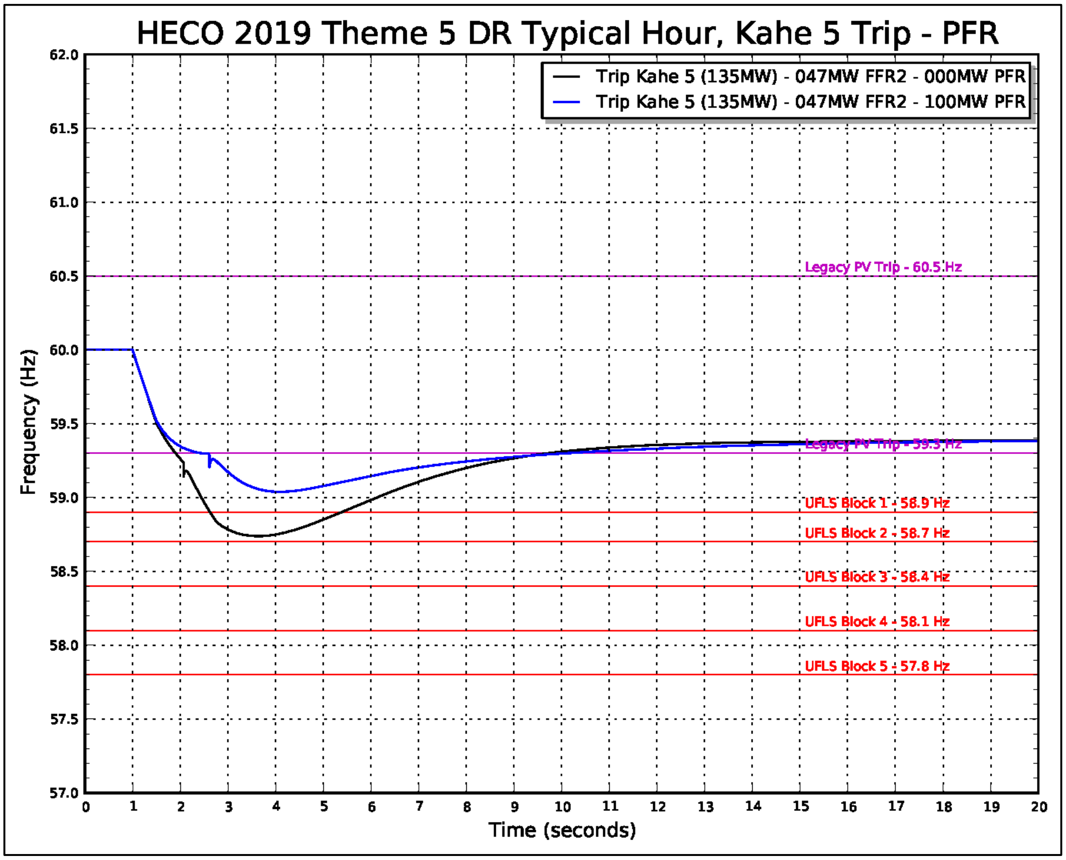

Figure O-125. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-125 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to 47 MW of FFR2 and 373 MW of upward regulation from thermal units.

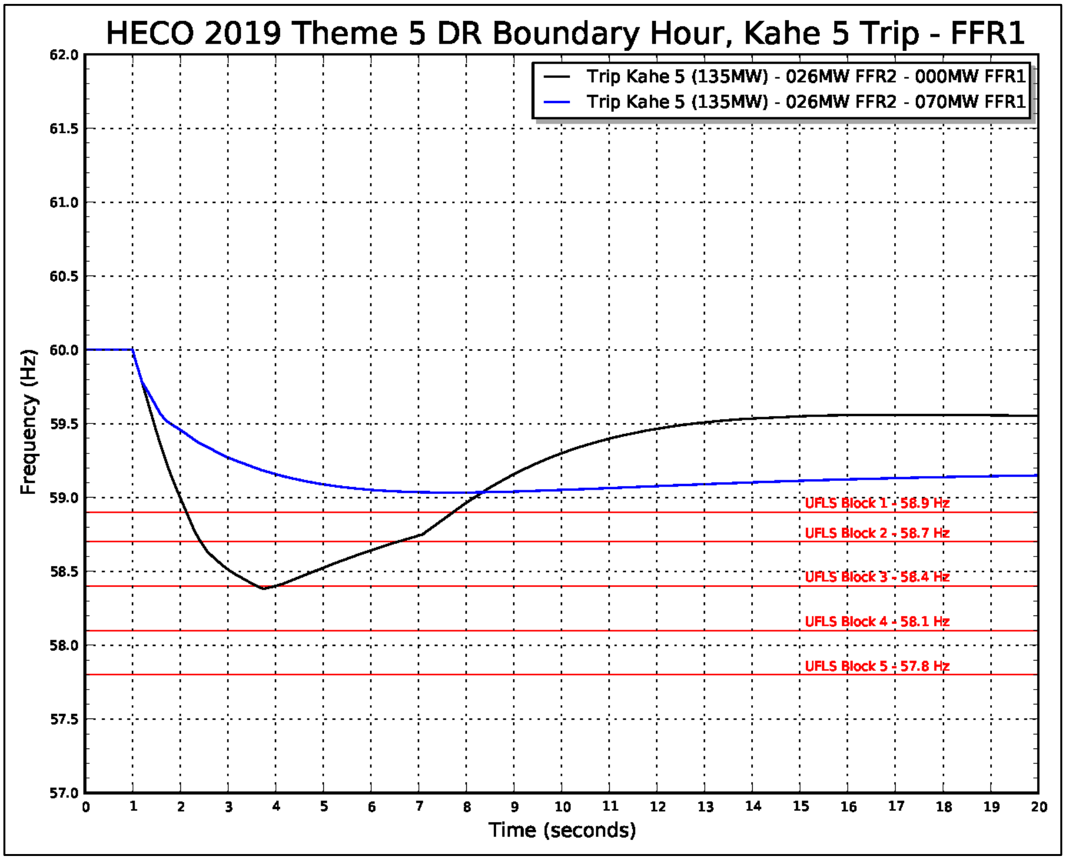

Figure O-126. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-126 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3411 MW-sec and the capacity of FFR2 is 26 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW.

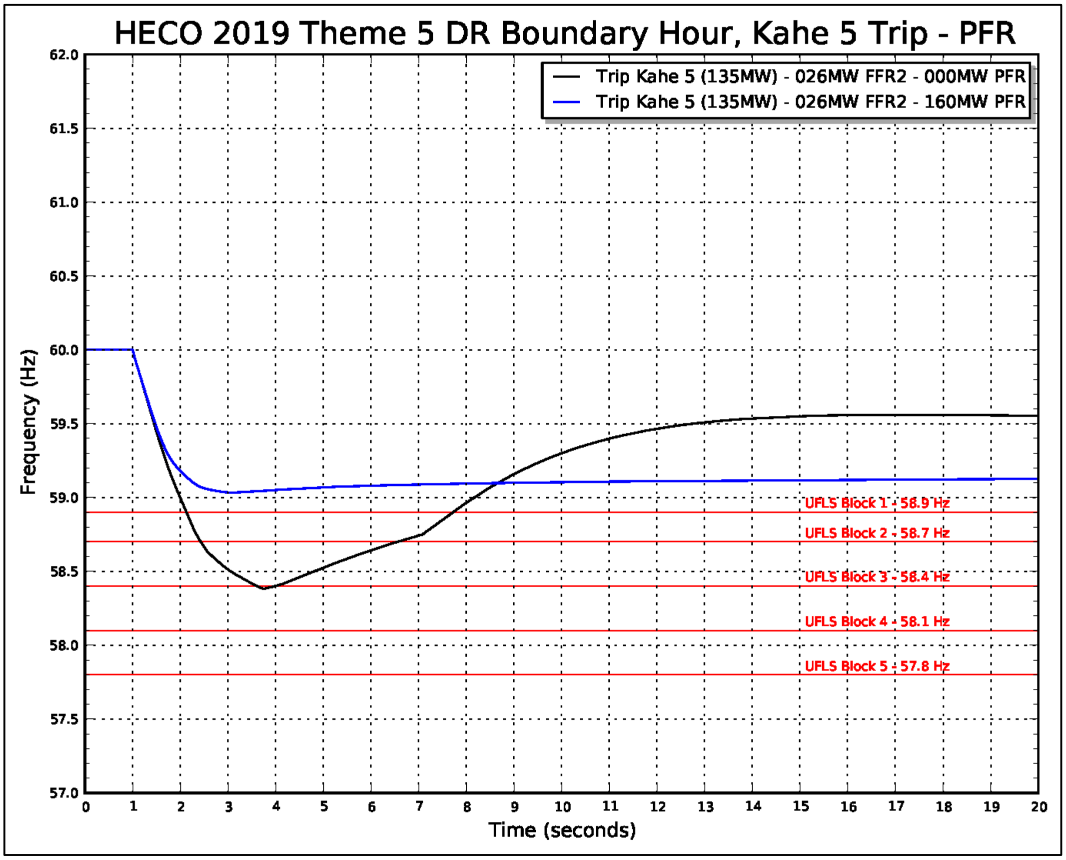

Figure O-127. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-127 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 160 MW. This is in addition to the 26 MW of FFR2 and 123 MW of upward regulation from thermal units.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							DR - Fault Sat 6/8/19 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	25.0	21.0	0.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	7.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256	25.0	28.7	1.2
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	133	0						77		
-Kahuku	30	0						21		
-Kawailoa	69	0						31		
-Na Pua Makani	24	0						21		
-CBRE Wind	10	0						4		
DG-PV	655	0						519		
Station PV	183	0						154		
Total Kinetic Energy									3917	
Total Load									1038	
Total Thermal Generation									288	
Total Renewable Generation									750	
Total Generation									1038	
Excess Generation									0	
Total Up Regulation									463	
Total Down Regulation									32	
Total FFR2 Capacity									39	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		57.9
	60.5Hz Capacity		215.9					60.5Hz Output		170.1

Table O-49. Unit Commitment and Dispatch Fault Analysis 2019

Table O-49 shows the unit commitment and dispatch for the fault analysis. The capacity of inverter-based PV generation is 673 MW.

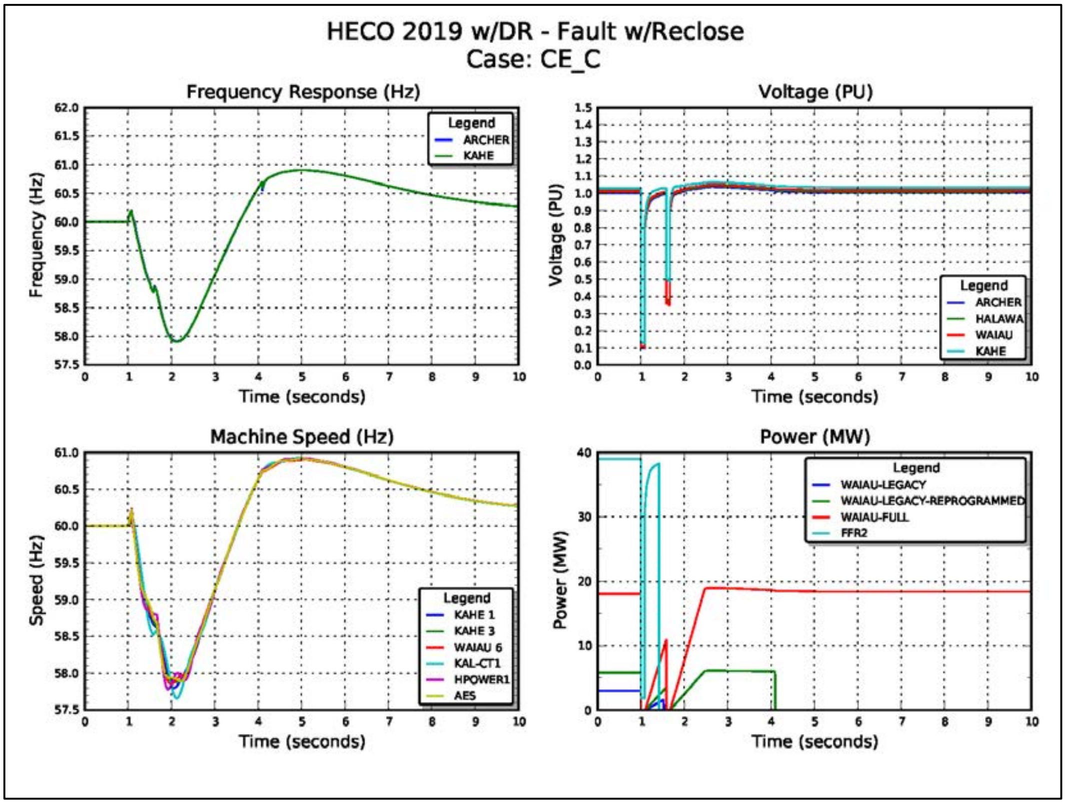

Figure O-128. System Performance for Normally Cleared Fault

Figure O-128 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverter remains connected to the system but output current drops to zero, essentially tripping 673 MW from the system. System frequency decays while system voltage is quickly restored on the breaker reclose. Generation from some DG-PV begins to recover upon restoration of voltage but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, demand response, and four blocks of UFLS is able to stabilize system frequency at 57.9 Hz and avoid system collapse but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Archer Substation that is indicative of DG-PV performance across the entire system. The under frequency trip setting for most synchronous units is initiated at 57.0 Hz and the frequency nadir for this fault is 57.9 Hz, providing a 0.9 Hz margin.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to bring the system into compliance with TPL-001.

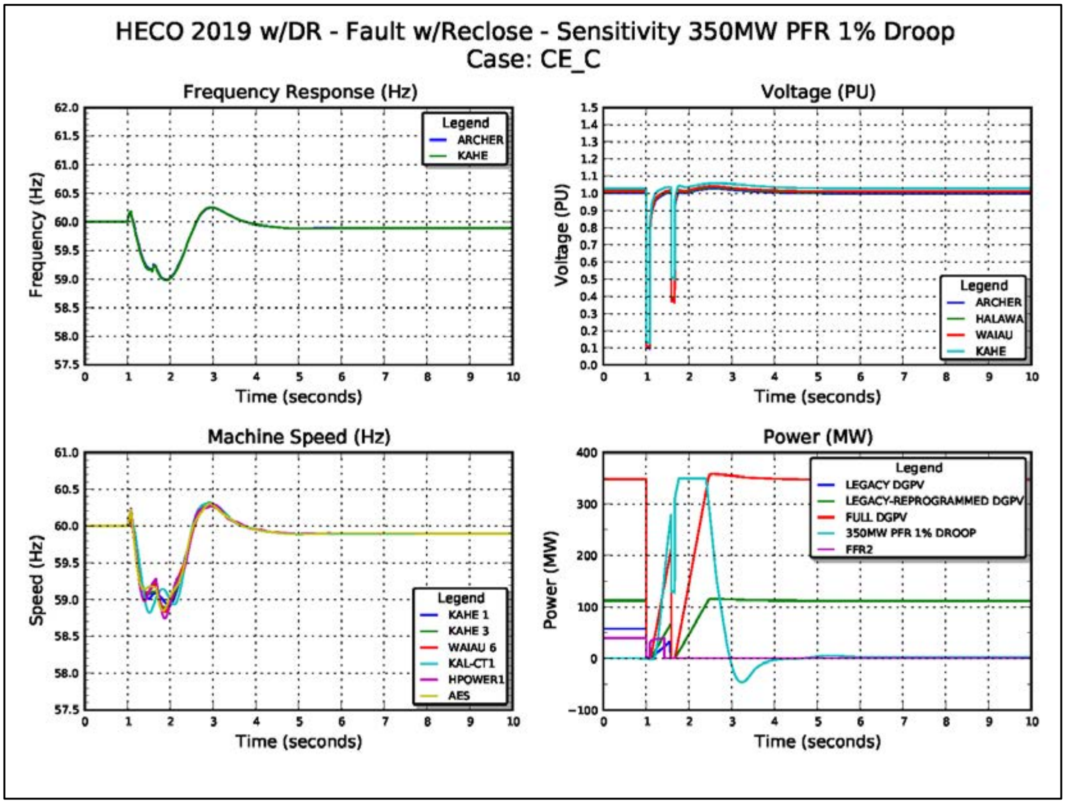

Figure O-129. System Performance Sensitivity Analysis 350 MW PFR

Figure O-129 shows system performance with the addition of 350 MW of PFR at 1% droop response. For the purpose of this analysis, a 350 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, demand response, 350 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

The breaker failure analysis produced similar results. The system remains stable with significant UFLS and demand response but the stability margin was compromised for each simulation. Further analysis is required to determine an optimal solution to maintain system stability for all circuits.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O'ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko'olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							DR-QV Dispatch Thu 7/23/2020 Hour 17		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	17.0	5.5	7.0
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	70.0	14.0	41.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	31.0	9.0	21.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	70.0	14.0	41.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	36.2	50.0	12.5
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	33.7	53.6	8.1
Kahe 5	134.6	21.0			4.36	158.8	692	48.9	85.7	27.9
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	163.0	0.0						73.1		
-Kahuku	30.0	0.0						18.9		
-Kawailoa	69.0	0.0						23.5		
-Na Pua Makani	24.0	0.0						18.7		
-CBRE Wind	10.0	0.0						3.0		
-Future Wind	30.0	0.0						9.0		
-Offshore Wind	0.0	0.0								
Total Station PV	362.2	0.0						210.2		
-KS2	5.0	0.0						2.1		
-KREP	5.0	0.0						2.7		
-Waianae	27.6	0.0						18.5		
-Kawailoa PV	49.0	0.0						30.0		
-Mililani 2	14.7	0.0						13.4		
-Waiawa	45.9	0.0						30.0		
-Westloch	20.0	0.0						9.5		
-CBRE PV	15.0	0.0						8.0		
-Future PV	180.0	0.0						95.9		
DG-PV	684.7	0.0						218.4		
Total Kinetic Energy									4269	
Total Load									1069	
Total Thermal Generation									565	
Total Renewable Generation									502	
Total Generation									1067	
Excess Generation									0	
Total Up Regulation									289	
Total Down Regulation									307	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		23.4
	60.5Hz Capacity		215.9					60.5Hz Output		68.9

Table O-50. Unit Commitment and Dispatch 2020 QV Analysis

Table O-50shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Thu 7/23/2020 Hour 17		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.9	33.1	-2.9
HPOWER-2	28.0	-16.0	2.9	25.1	-18.9
AES	99.4	-49.8	27.3	72.1	-77.1
Kalaeloa CT-1	84.5	-35.9	14.5	70.0	-50.4
Kalaeloa ST	42.1	-16.7	14.5	27.6	-31.2
Kalaeloa CT-2	84.5	-35.8	14.5	70.0	-50.3
Kahe 1	68.3	-51.6	27.9	40.4	-79.5
Kahe 2	64.4	-50.3			
Kahe 3	71.2	-21.3	27.9	43.3	-49.2
Kahe 4	64.6	-21.5	27.9	36.7	-49.4
Kahe 5	112.5	-69.0	93.1	19.4	-162.1
Kahe 6	106.6	-61.3			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	96.7	-120.3	5.7	91.1	-125.9
-Kahuku	17.9	-17.9	4.2	13.6	-22.1
-Kawailoa	50.0	-74.5	3.2	46.8	-77.7
-Na Pua Makani	16.4	-15.4	-1.8	18.2	-13.6
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	165.6	-165.6	13.4	152.2	-179.0
-KS2	1.6	-1.6	0.2	1.5	-1.8
-KREP	2.0	-2.0	1.6	0.4	-3.6
-Waianae	14.5	-14.5	1.4	13.1	-15.9
-Kawailoa PV	36.8	-36.8	-0.5	37.3	-36.2
-Mililani 2	10.7	-10.7	0.0	10.7	-10.7
-Waiawa	32.9	-32.9	0.5	32.4	-33.3
-Westloch	6.3	-6.3	2.4	3.8	-8.7
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	56.2	-56.2	7.9	48.3	-64.1
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			253.8		
Total Renewable MVAR Generation			19.0		
Total Cap Bank MVAR			185.6		
Charging MVAR			77.3		
Total MVAR Supply			535.7		
Total MVAR Load			348.1		
Total MVAR Losses			187.8		
Excess MVAR Generation			-0.1		
Total MVAR Supply Capability				680.7	
Total MVAR Absorb Capability					-876.3

Table O-51. MVAR Capability 2020 QV Analysis

Table O-51 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
244	Halawa-School & Makalapa-Airport
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-52. N-2 Contingencies 2020 QV Analysis

Table O-52 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

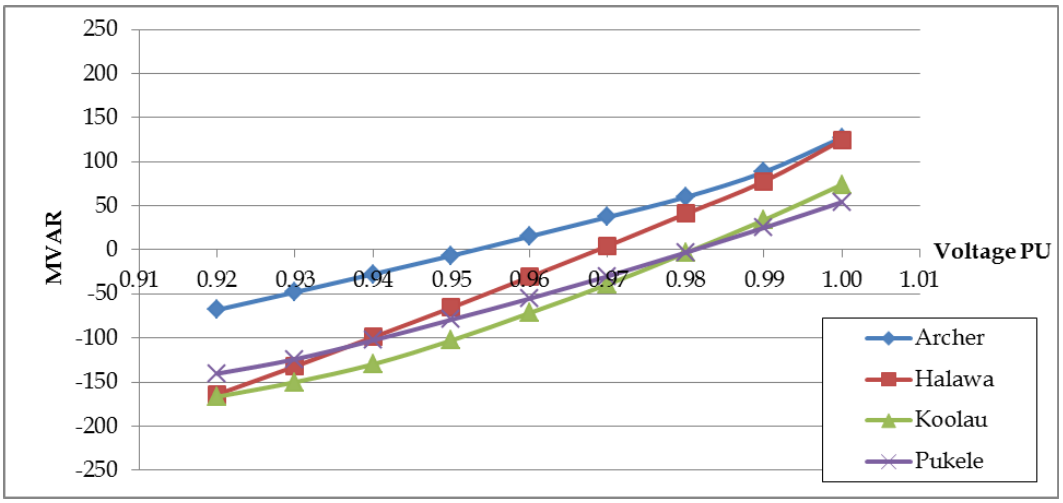

Figure O-130. QV Curves 2020

Figure O-130 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. The unit commitment and dispatch meets the reactive power requirements of the system under N-2 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	127	154	88	244	60	135	37	135	15	135	-7	135	-28	135	-48	135	-68
120	Halawa	125	125	154	77	154	41	154	4	154	-31	154	-66	154	-99	154	-132	154	-164
150	Koolau	125	74	154	34	154	-4	125	-39	125	-72	125	-103	125	-130	316	-150	316	-167
170	Pukele	125	54	154	25	154	-3	125	-30	125	-55	125	-79	125	-103	125	-124	316	-140

Table O-53. Summary of Results 2020 QV Analysis

Table O-53 shows the results of the 2020 QV analysis. The unit commitment and dispatch is able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

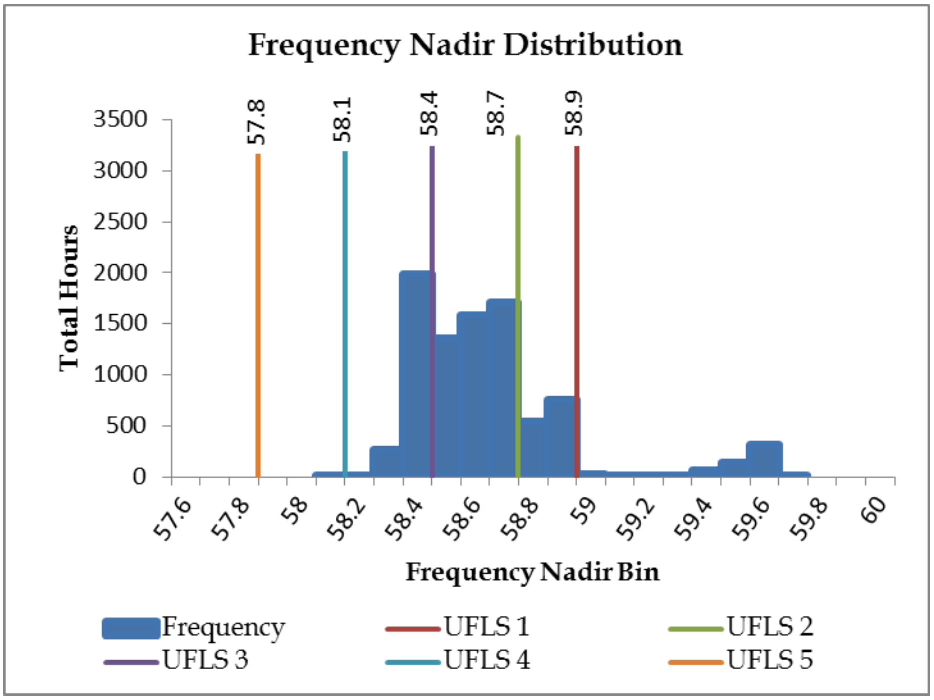

Figure O-131. Frequency Nadir Histogram 2020

Figure O-131 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1980 hours was 11:00 AM on Friday, January 31. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 3 hours was 3:00 AM on Thursday, January 30. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

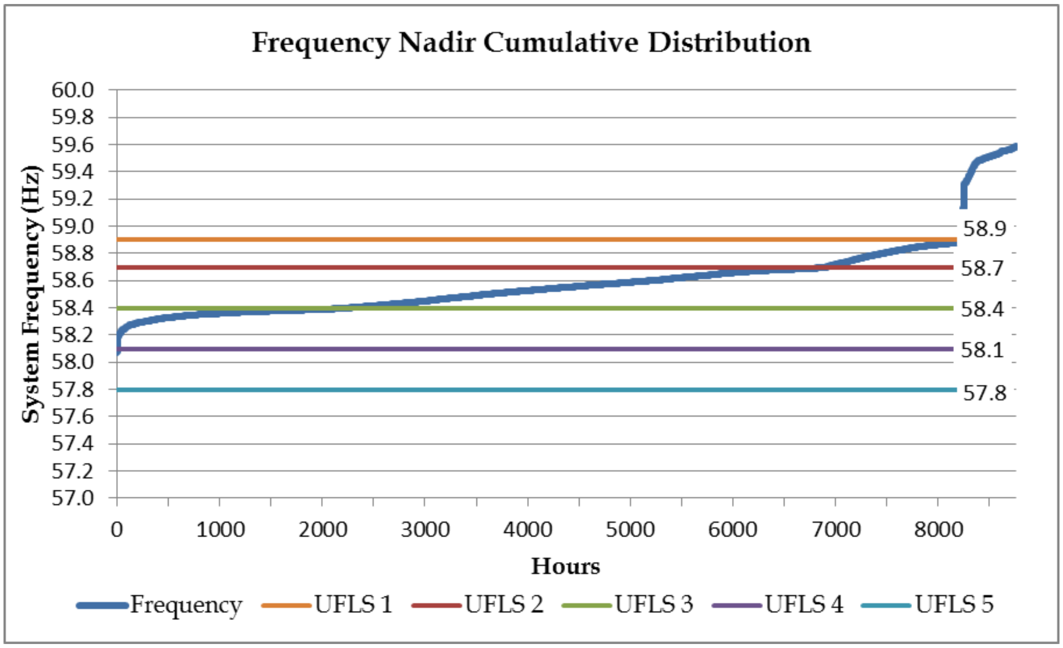

Figure O-132. Frequency Nadir Duration Curve 2020

Figure O-132 shows the frequency nadir duration curve for 2020. The system is at risk of UFLS for 8188 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Fri 1/31/20 Hour 11			DR - AES Trip Boundary Thu 1/30/20 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.2	10.8	10.2	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	72.7	11.3	43.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	17.3	2.7	7.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	32.1	50.1	8.3
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	28.3	57.9	4.6	45.4	40.8	21.7
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4	31.7	53.6	8.1
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426	25.0	58.3	1.2			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	25.0	61.2	0.9			
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	163	0						17			55		
-Kahuku	30	0						1			22		
-Kawailoa	69	0						4			26		
-Na Pua Makani	24	0						0			0		
-CBRE Wind	10	0						3			2		
DG-PV	685	0						367			0		
Station PV	363	0						272			0		
Total Kinetic Energy									3838			3433	
Total Load									1109			597	
Total Thermal Generation									453			541	
Total Renewable Generation									657			55	
Total Generation									1109			597	
Excess Generation									0			0	
Total Up Regulation									332			156	
Total Down Regulation									197			314	
Total FFR2 Capacity									49			35	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		39.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		114.4	60.5Hz Output		0.0

Table O-54. Unit Commitment and Dispatch 2020

Table O-54 shows the unit commitment and dispatch for the typical hour (1/31/20, 11:00 AM) and boundary hour (1/30/20, 3:00 AM).

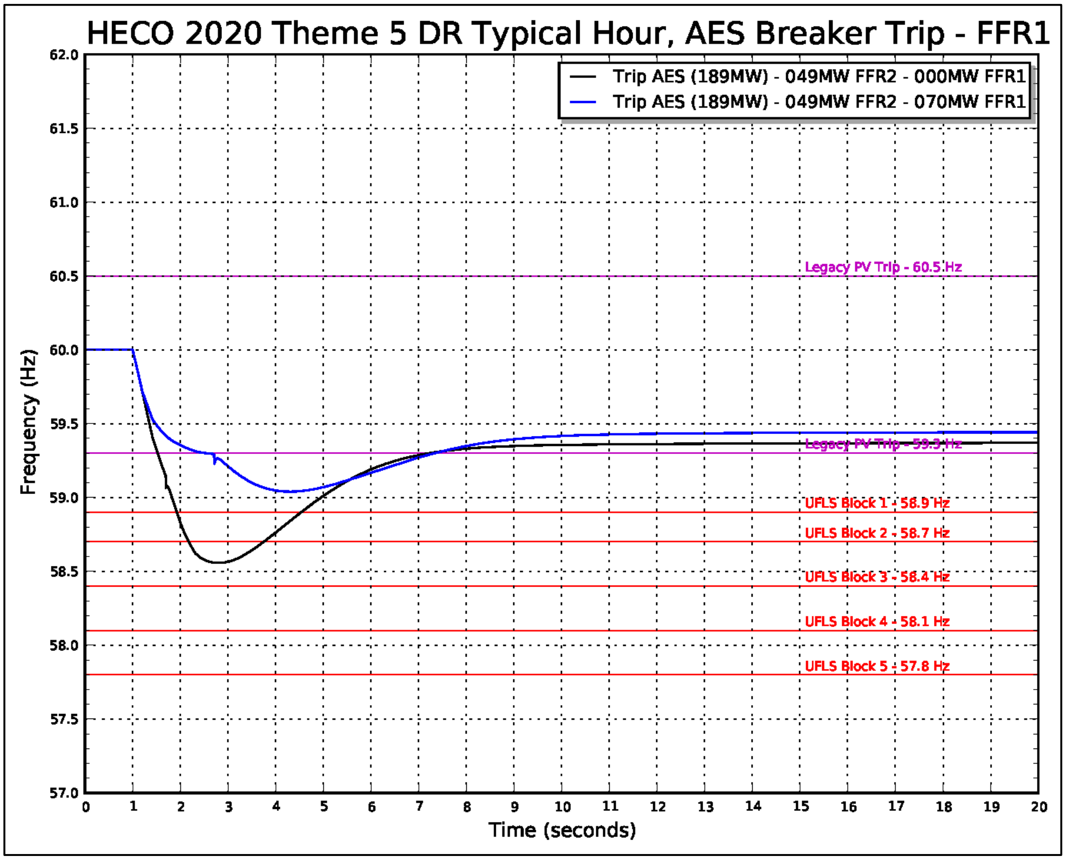

Figure O-133. Frequency Response Profile FFR1 Typical Hour

Figure O-133 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3838 MW-sec, the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 39 MW, and the capacity of FFR2 is 49 MW. With no FFR1, the frequency nadir is 58.6 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 49 MW of FFR2.

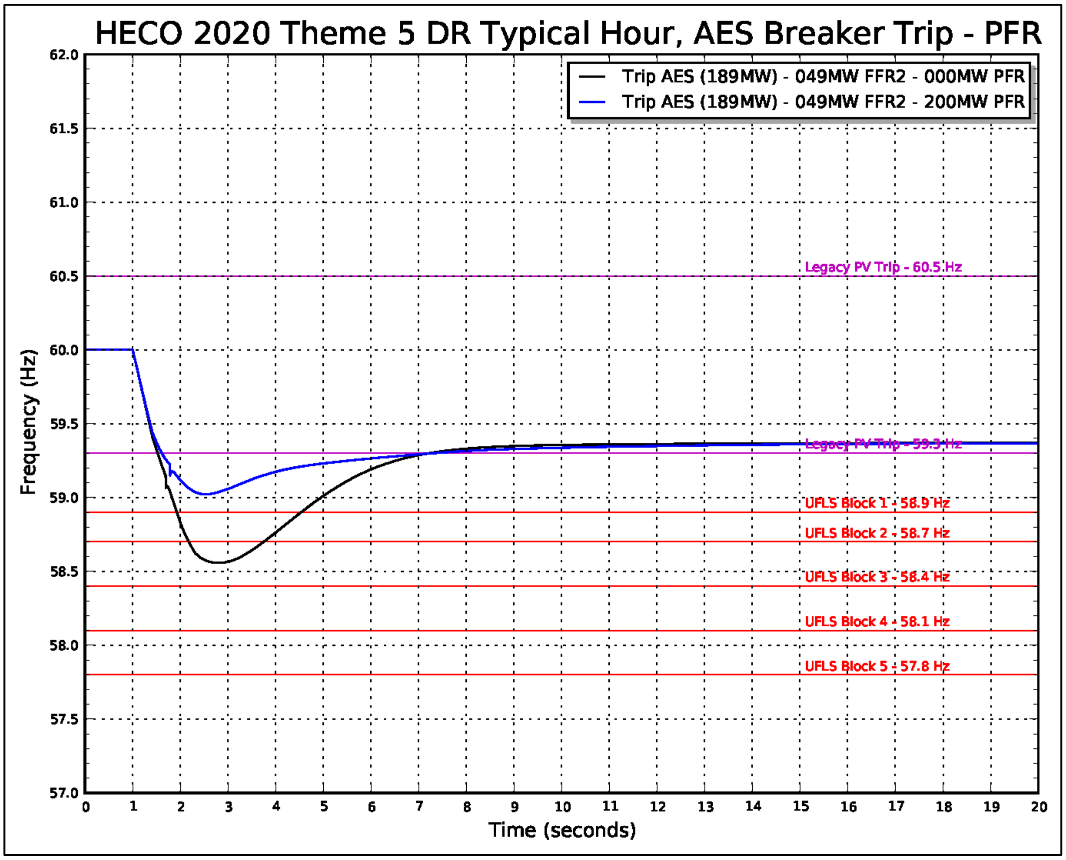

Figure O-134. Frequency Response Profile PFR Typical Hour

Figure O-134 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 49 MW of FFR2 and 332 MW of upward regulation from thermal generation.

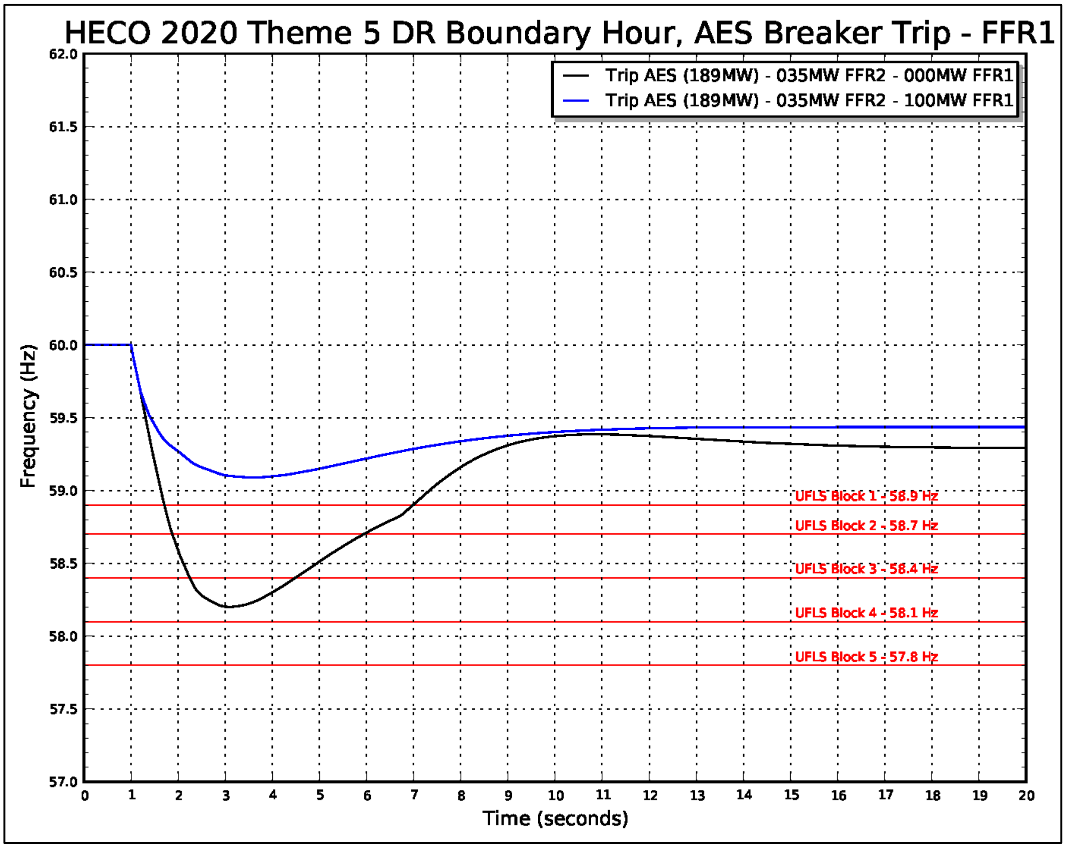

Figure O-135. Frequency Response Profile FFR1 Boundary Hour

Figure O-135 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3433 MW-sec and the capacity of FFR2 is 35 MW. With no FFR1, the frequency nadir breaches 58.3 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 35 MW of FFR2.

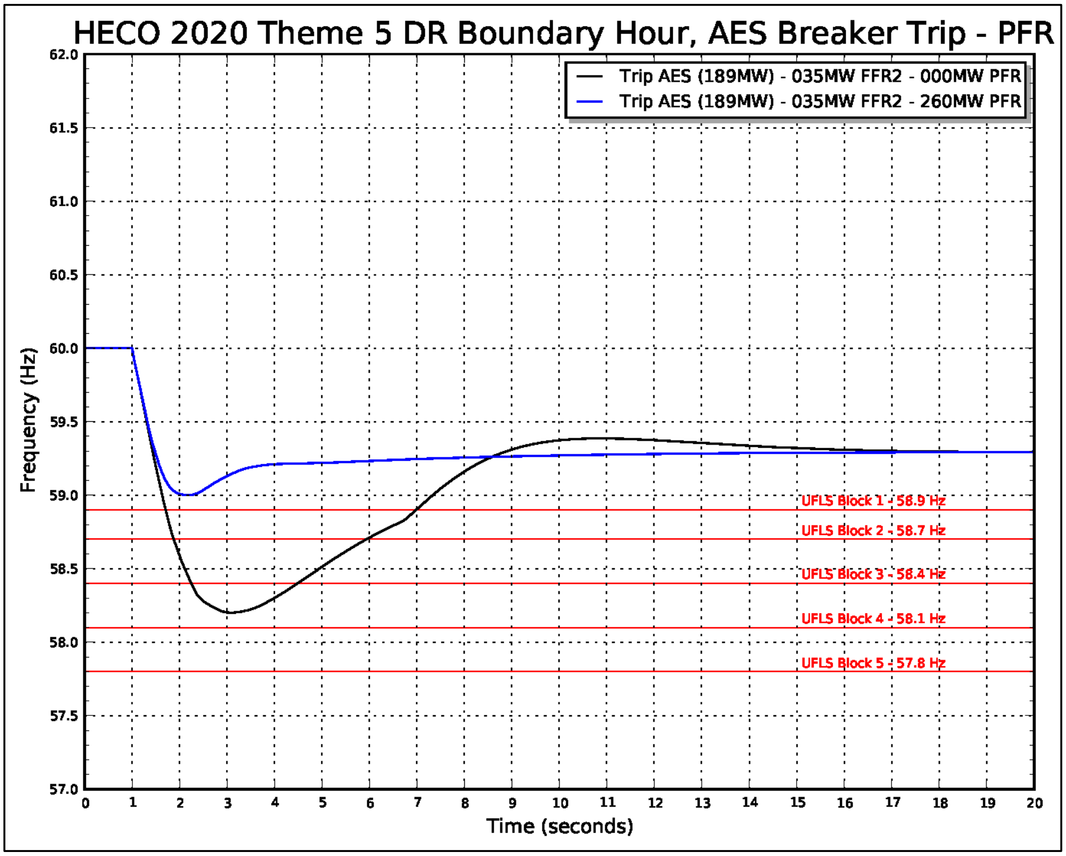

Figure O-136. Frequency Response Profile PFR Typical Hour

Figure O-136 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 35 MW of FFR2 and 156 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip Typical Fri 1/31/20 Hour 11			DR - K5 Trip Boundary Thu 1/30/20 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.2	10.8	10.2	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	104.0	85.0	41.0	131.0	58.0	68.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	72.7	11.3	43.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	17.3	2.7	7.3	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2	32.1	50.1	8.3
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	28.3	57.9	4.6			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4			
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Total Wind	163	0						17			55		
-Kahuku	30	0						1			22		
-Kawailoa	69	0						4			26		
-Na Pua Makani	24	0						0			0		
-CBRE Wind	10	0						3			2		
DG-PV	685	0						367			0		
Station PV	363	0						272			0		
Total Kinetic Energy									3678			3411	
Total Load									1109			597	
Total Thermal Generation									452			541	
Total Renewable Generation									657			55	
Total Generation									1109			596	
Excess Generation									0			0	
Total Up Regulation									298			119	
Total Down Regulation									223			340	
Total FFR2 Capacity									49			35	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		39.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		114.4	60.5Hz Output		0.0

Table O-55. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-55 shows the unit commitment and dispatch for the typical hour (1/31/20, 11:00 AM) and boundary hour (1/30/20, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

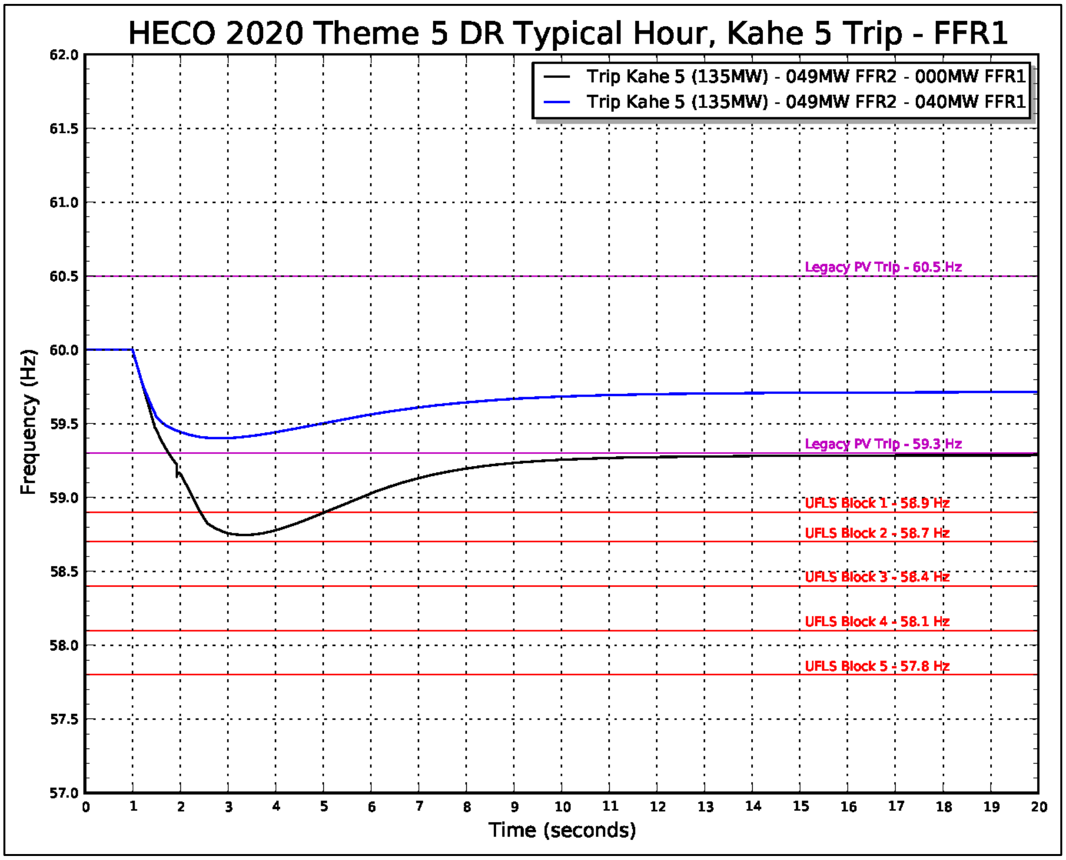

Figure O-137. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-137 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3678 MW-sec, the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 39 MW, and the capacity of FFR2 is 49 MW. With no FFR1, the frequency nadir is 58.8 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 40 MW. This is in addition to the 49 MW of FFR2.

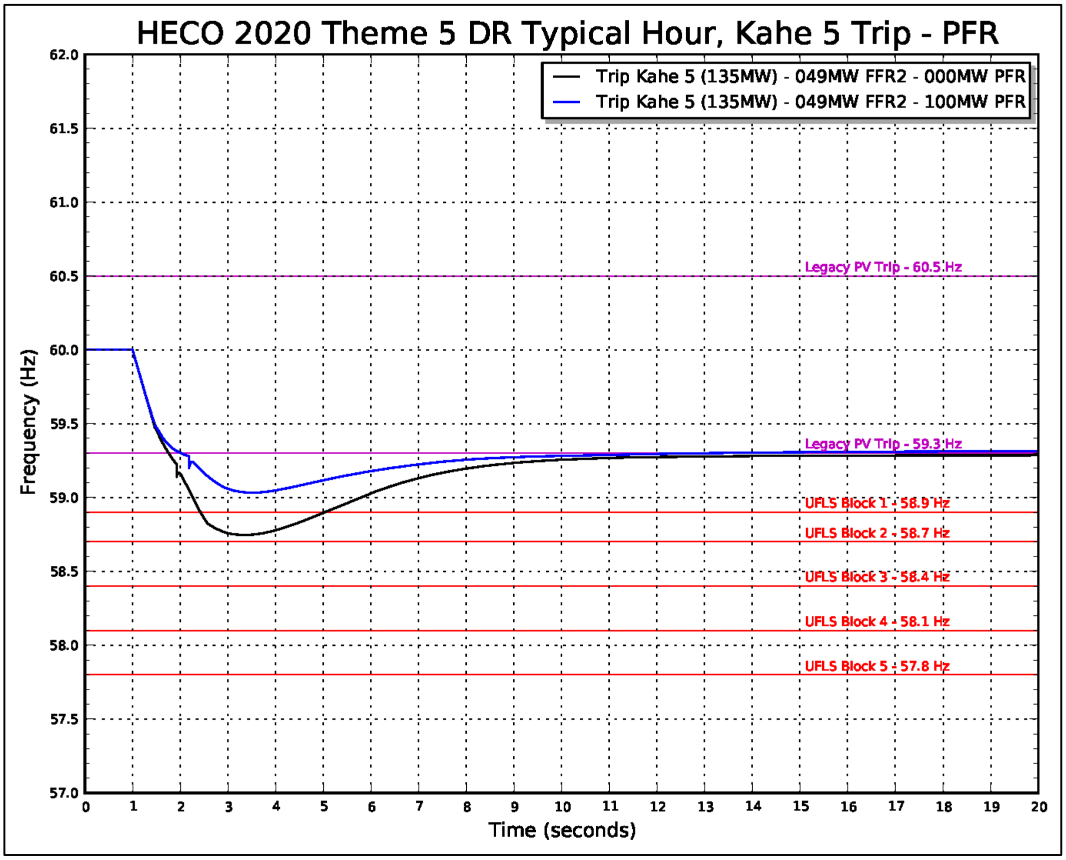

Figure O-138. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-138 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 49 MW of FFR2 and 298 MW of upward regulation from thermal generation.

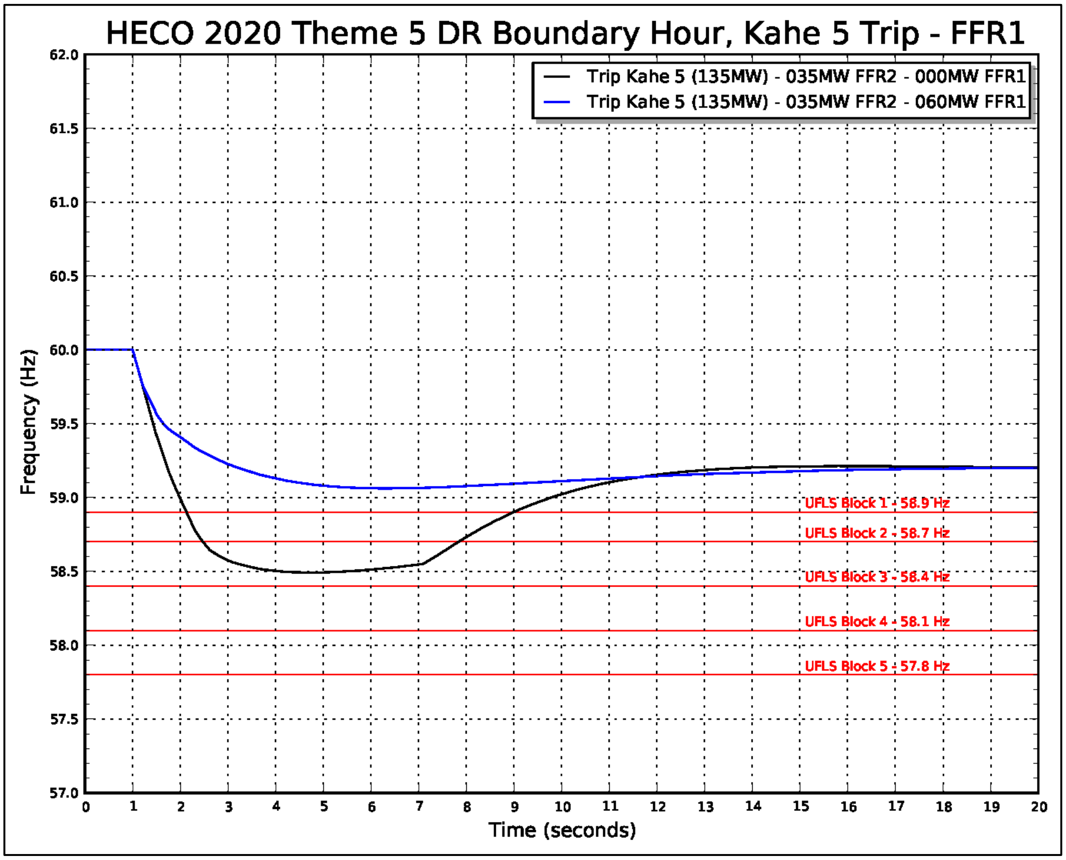

Figure O-139. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-139 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3411 MW-sec and the capacity of FFR2 is 35 MW. With no FFR, the frequency nadir is 58.5 Hz and two blocks of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 35 MW of FFR2.

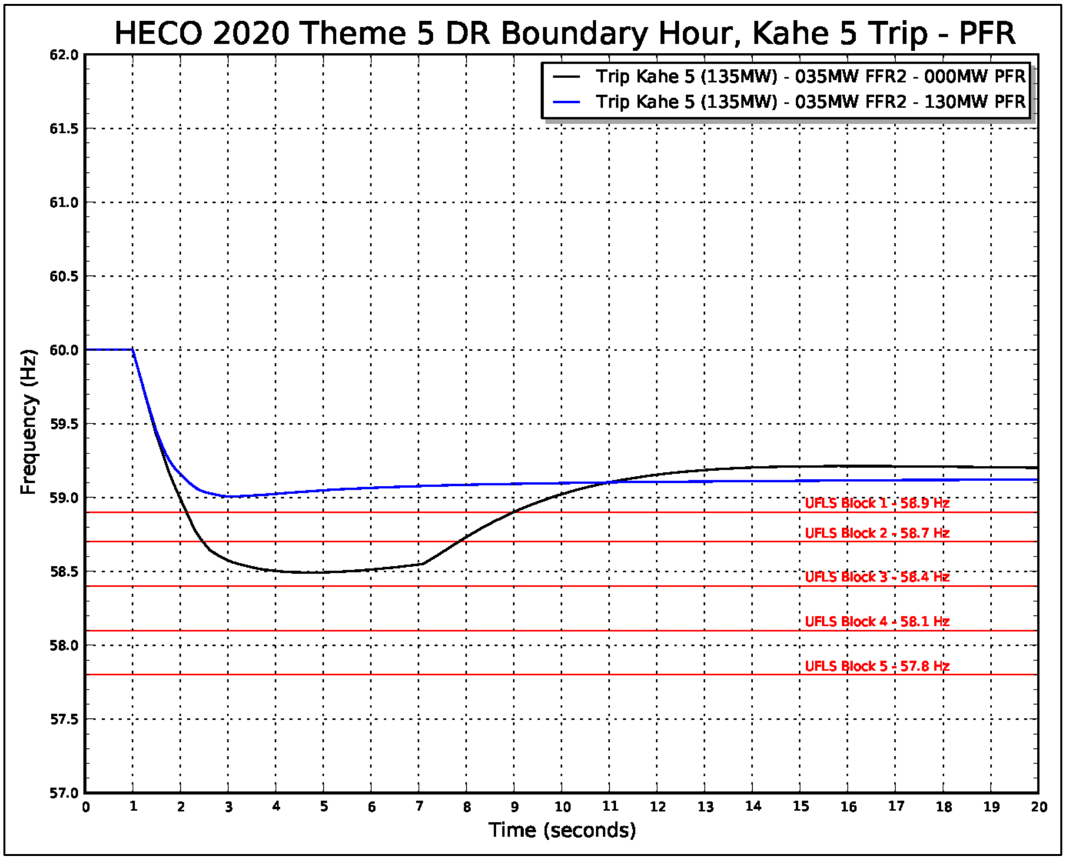

Figure O-140. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-140 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 130 MW. This is in addition to the 35 MW FFR2 and 119 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							DR - Fault Wed 5/27/20 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	28.7	17.3	3.7
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.5	125.5	0.5
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	7.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Total Wind	163	0						53		
-Kahuku	30	0						11		
-Kawailoa	69	0						17		
-Na Pua Makani	24	0						17		
-CBRE Wind	10	0						2		
DG-PV	685	0						542		
Station PV	363	0						346		
Total Kinetic Energy									3411	
Total Load									1208	
Total Thermal Generation									267	
Total Renewable Generation									941	
Total Generation									1208	
Excess Generation									0	
Total Up Regulation									430	
Total Down Regulation									35	
Total FFR2 Capacity									55	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		57.7
	60.5Hz Capacity			215.9				60.5Hz Output		169.5

Table O-56. Unit Commitment and Dispatch Fault Analysis 2020

Table O-56 shows the unit commitment and dispatch for the fault analysis. The capacity of inverter-based PV generation is 888 MW and the capacity of demand response is 55 MW.

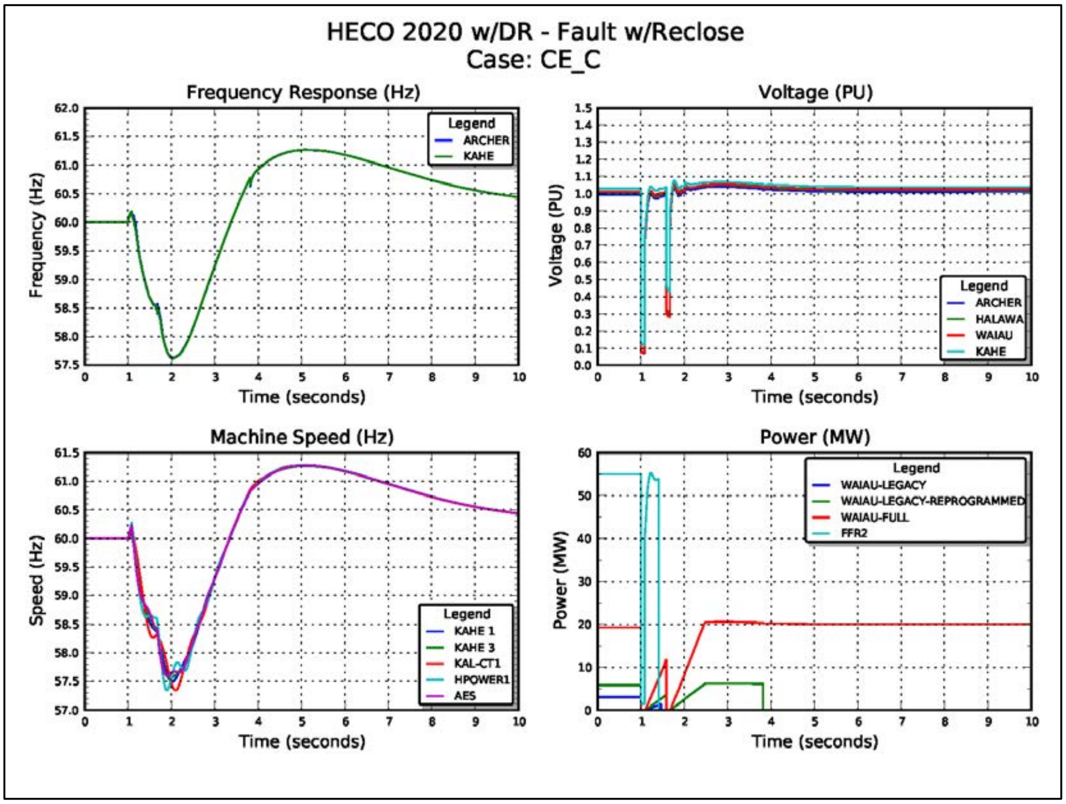

Figure O-141. System Performance for Normally Cleared Fault

Figure O-141 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverter remains connected to the system but its output current drops to zero, essentially tripping 888 MW from the system. System frequency decays while system voltage is quickly restored on the breaker reclose. Generation from some DG-PV begins to recover upon restoration of voltage but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, demand response, and five blocks of UFLS is able to stabilize system frequency at 57.6 Hz but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Waiau is indicative of DG-PV performance across the entire system. The under frequency trip setting for most synchronous units is initiated at 57.0 Hz and the frequency nadir for this fault is 57.6 Hz, providing a 0.6 Hz margin.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to bring the system into compliance with TPL-001.

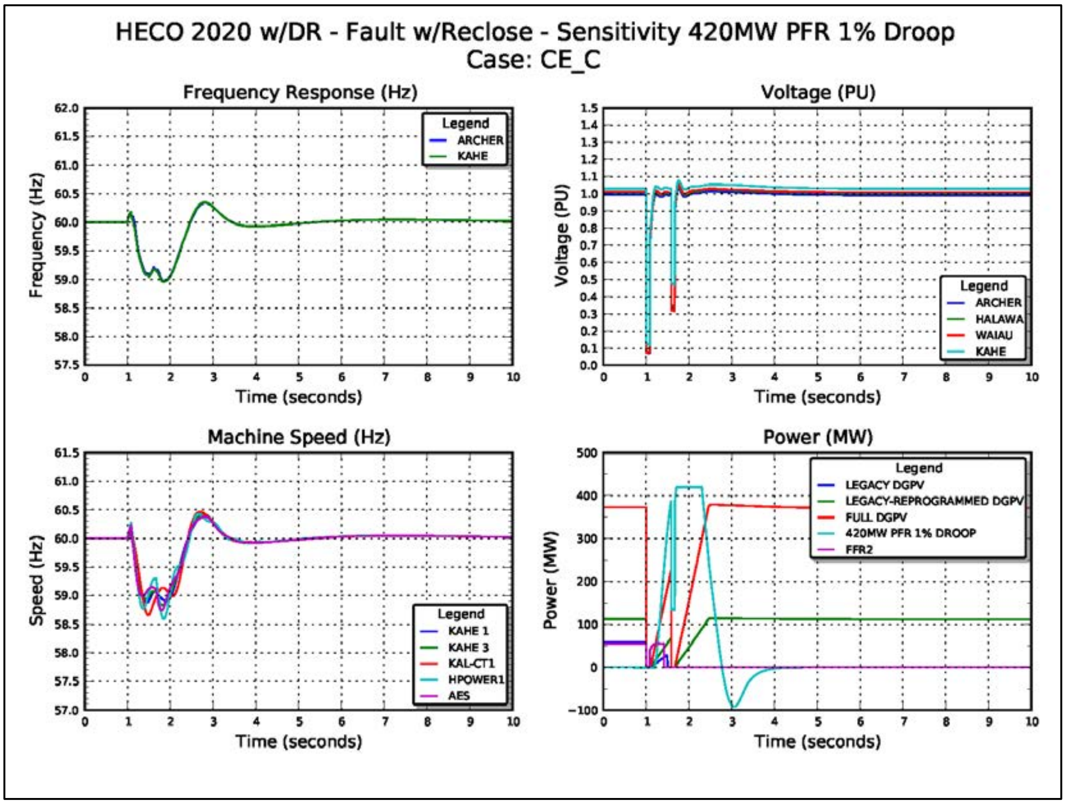

Figure O-142. System Performance Sensitivity Analysis 420 MW PFR

Figure O-142 shows system performance with the addition of 420 MW of PFR at 1% droop response. For the purpose of this analysis, a 420 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, demand response, 420 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

The breaker failure analysis produced similar results. The system remains stable with significant UFLS and demand response but the stability margin was compromised for each simulation. Further analysis is required to determine an optimal solution to bring the system into compliance with TPL-001 and increase the stability margin of the system.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-2 contingency events. For O‘ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko‘olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings							DR - QV Dispatch Sun 9/19/2021 Hour 15		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	55.0	29.0	26.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	19.9	20.1	9.9
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	55.0	29.0	26.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	27.0	58.3	3.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261			
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
Honolulu 8	0.0	0.0			1.99	62.5	124			
Honolulu 9	0.0	0.0			1.95	64.0	125			
Total Wind	163.0	0.0						52.2		
-Kahuku	30.0	0.0						8.7		
-Kawailoa	69.0	0.0						14.5		
-Na Pua Makani	24.0	0.0						17.0		
-CBRE Wind	10.0	0.0						3.0		
-Future Wind	30.0	0.0						9.0		
-Offshore Wind	0.0	0.0								
Total Station PV	462.2	0.0						236.3		
-KS2	5.0	0.0						3.4		
-KREP	5.0	0.0						2.7		
-Waianae	27.6	0.0						21.3		
-Kawailoa PV	49.0	0.0						37.7		
-Mililani 2	14.7	0.0						11.3		
-Waiawa	45.9	0.0						35.3		
-Westloch	20.0	0.0						14.3		
-CBRE PV	15.0	0.0						5.6		
-Future PV	280.0	0.0						104.7		
DG-PV	712.0	0.0						393.6		
Total Kinetic Energy									4003	
Total Load									1172	
Total Thermal Generation									489	
Total Renewable Generation									682	
Total Generation									1172	
Excess Generation									0	
Total Up Regulation									312	
Total Down Regulation									228	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		40.6
	60.5Hz Capacity			215.9				60.5Hz Output		119.3

Table O-57. Unit Commitment and Dispatch 2021 QV Analysis

Table O-57 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Sun 9/19/2021 Hour 15		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.2	33.8	-2.2
HPOWER-2	28.0	-16.0	2.2	25.8	-18.2
AES	99.4	-49.8	29.7	69.7	-79.5
Kalaeloa CT-1	84.5	-35.9	14.9	69.6	-50.8
Kalaeloa ST	42.1	-16.7	14.9	27.2	-31.6
Kalaeloa CT-2	84.5	-35.8	14.9	69.6	-50.7
Kahe 1	68.3	-51.6	43.1	25.2	-94.7
Kahe 2	68.3	-51.6	43.1	25.2	-94.7
Kahe 3	74.2	-25.0	43.1	31.1	-68.1
Kahe 4	66.5	-23.1	64.3	2.2	-87.4
Kahe 5	112.5	-69.0			
Kahe 6	106.6	-61.3			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0			
Hon 9 (Sync Cond)	51.0	-33.0			
Total Wind	96.7	-120.3	7.4	89.3	-127.7
-Kahuku	17.9	-17.9	4.4	13.4	-22.3
-Kawailoa	50.0	-74.5	4.2	45.8	-78.7
-Na Pua Makani	16.4	-15.4	-1.2	17.6	-14.3
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	196.8	-196.8	16.5	180.3	-213.4
-KS2	1.6	-1.6	0.5	1.2	-2.1
-KREP	2.0	-2.0	1.8	0.2	-3.8
-Waianae	14.5	-14.5	2.2	12.4	-16.7
-Kawailoa PV	36.8	-36.8	0.0	36.7	-36.8
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.5
-Waiawa	32.9	-32.9	1.2	31.7	-34.0
-Westloch	6.3	-6.3	2.4	3.8	-8.7
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	87.4	-87.4	8.7	78.7	-96.1
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			272.4		
Total Renewable MVAR Generation			24.0		
Total Cap Bank MVAR			184.0		
Charging MVAR			76.9		
Total MVAR Supply			557.2		
Total MVAR Load			382.1		
Total MVAR Losses			175.6		
Excess MVAR Generation			-0.5		
Total MVAR Supply Capability				649.1	
Total MVAR Absorb Capability					-918.9

Table O-58. MVAR Capability 2021 QV Analysis

Table O-58 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe-Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
244	Halawa-School & Makalapa-Airport
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-59. N-2 Contingencies 2021 QV Analysis

Table O-59 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

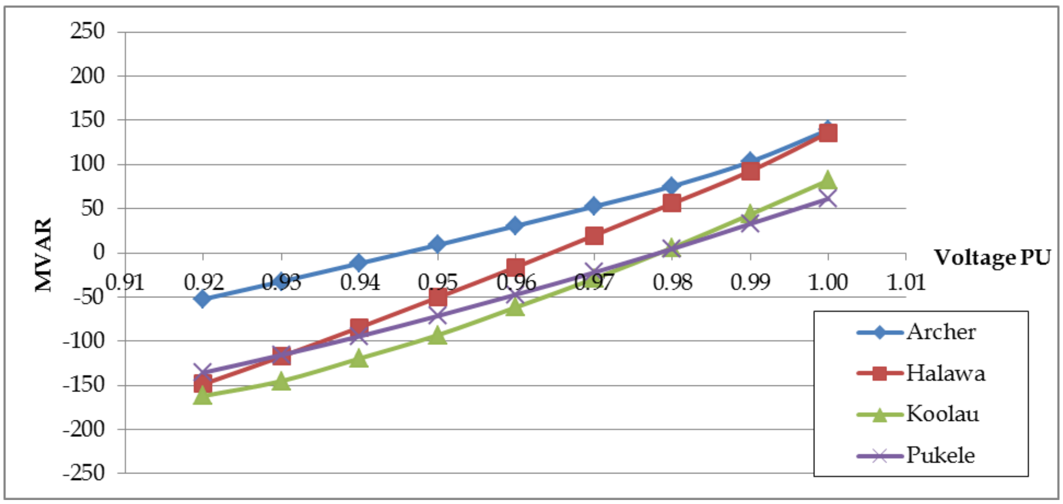

Figure O-143. QV Curves 2021

Figure O-143 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation requires an additional 9 MVAR to maintain system voltage at 0.95 PU for an N-2 contingency. The system has 649 MVAR of reactive power reserve capacity but all of these resources are on the west side of the island, far from the load center.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	139	154	103	244	75	135	52	135	31	135	9	135	-12	135	-32	135	-52
120	Halawa	125	136	154	93	154	56	154	20	154	-16	154	-50	154	-84	154	-117	154	-149
150	Koolau	154	82	154	43	154	6	125	-29	125	-62	125	-93	125	-119	316	-145	316	-162
170	Pukele	154	61	154	33	154	4	125	-22	125	-47	125	-71	125	-94	125	-116	125	-136

Table O-60. Results 2021 QV Analysis

Table O-60 shows the results of the 2021 QV analysis. Archer Substation requires an additional 9 MVARS to meet the reactive power requirements under N-2 contingencies.

To mitigate the reactive power shortfall at Archer Substation, a sensitivity analysis was performed with Honolulu 8 and 9 synchronous condensers added to the system.

Unit	Unit Ratings		DR - QV MVAR Capability Sun 9/19/2021 Hour 15		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
HPOWER-1	36.0	0.0	2.2	33.8	-2.2
HPOWER-2	28.0	-16.0	2.2	25.8	-18.2
AES	99.4	-49.8	26.0	73.4	-75.8
Kalaeloa CT-1	84.5	-35.9	13.1	71.4	-49.0
Kalaeloa ST	42.1	-16.7	13.1	29.0	-29.8
Kalaeloa CT-2	84.5	-35.8	13.1	71.4	-48.9
Kahe 1	68.3	-51.6	34.1	34.2	-85.7
Kahe 2	68.3	-51.6	34.1	34.2	-85.7
Kahe 3	74.2	-25.0	34.1	40.1	-59.1
Kahe 4	66.7	-23.2	64.3	2.4	-87.5
Kahe 5	112.5	-69.0			
Kahe 6	106.6	-61.3			
Waiau 3	41.0	-35.0			
Waiau 4	40.0	0.0			
Waiau 5	51.0	-35.0			
Waiau 6	51.0	-33.0			
Waiau 7	71.0	-52.0			
Waiau 8	71.0	-52.0			
Waiau 9	41.0	0.0			
Waiau 10	41.0	0.0			
Hon 8 (Sync Cond)	51.0	-33.0	16.1	34.9	-49.1
Hon 9 (Sync Cond)	51.0	-33.0	16.1	34.9	-49.1
Total Wind	96.7	-120.3	5.4	91.4	-125.7
-Kahuku	17.9	-17.9	4.2	13.7	-22.0
-Kawailoa	50.0	-74.5	3.5	46.5	-78.0
-Na Pua Makani	16.4	-15.4	-2.3	18.7	-13.1
-CBRE Wind	3.1	-3.1	0.0	3.1	-3.1
-Future Wind	9.4	-9.4	0.0	9.3	-9.4
-Offshore Wind	0.0	0.0			
Total Station PV	196.8	-196.8	15.1	181.7	-212.0
-KS2	1.6	-1.6	0.5	1.2	-2.1
-KREP	2.0	-2.0	1.8	0.2	-3.8
-Waianae	14.5	-14.5	2.2	12.4	-16.7
-Kawailoa PV	36.8	-36.8	0.0	36.7	-36.8
-Mililani 2	10.7	-10.7	-0.3	11.0	-10.4
-Waiawa	32.9	-32.9	0.8	32.0	-33.7
-Westloch	6.3	-6.3	2.9	3.4	-9.1
-CBRE PV	4.7	-4.7	0.0	4.7	-4.7
-Future PV	87.4	-87.4	7.3	80.1	-94.7
DG-PV	0.0	0.0	0.0	0.0	0.0
Total Thermal MVAR Generation			268.3		
Total Renewable MVAR Generation			20.5		
Total Cap Bank MVAR			185.5		
Charging MVAR			77.6		
Total MVAR Supply			551.9		
Total MVAR Load			382.1		
Total MVAR Losses			169.8		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				758.8	
Total MVAR Absorb Capability					-977.5

Table O-61. MVAR Capability 2021 QV Sensitivity Analysis

Table O-61 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch with the addition of the Honolulu 8 and 9 synchronous condensers.

Con #	Contingency Description
125	CEIP-Ewa Nui & Kalaeloa-Ewa Nui
154	Kahe_Halawa 1 & Kahe-Halawa 2
135	Halawa-Iwilei & Halawa-School
203	Halawa-Koolau & Waiau-Koolau 1
244	Halawa-School & Makalapa-Airport
316	Waiau-Koolau 1 & Waiau-Koolau 2

Table O-62. N-2 Contingencies 2021 Sensitivity Analysis

Table O-62 shows the N-2 contingencies that have the biggest impact to MVAR requirements for the critical busses.

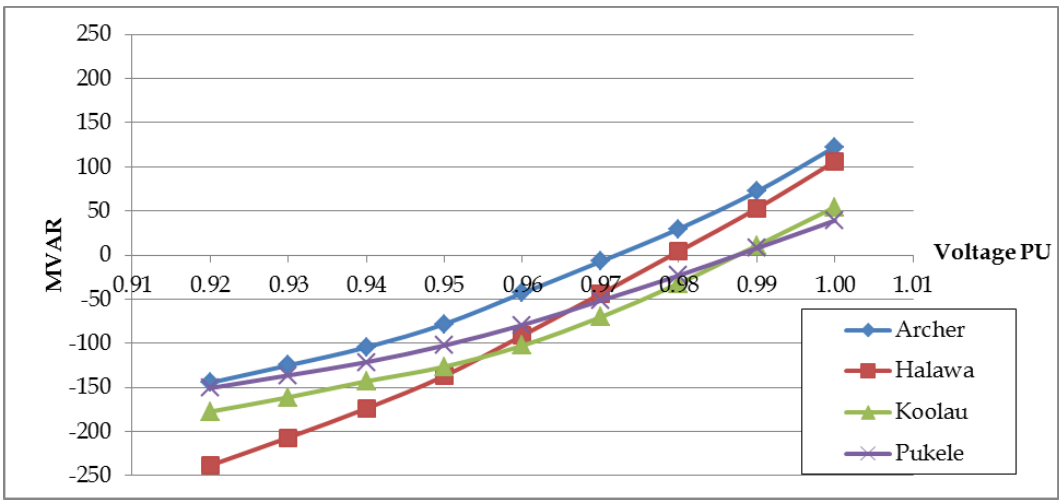

Figure O-144. QV Curves with H8 & H9 Synchronous Condensers

Figure O-144 shows the QV curves for the Archer, Halawa, Ko'olau, and Pukele busses for the worst-case N-2 contingency event. Archer Substation is able to maintain bus voltage at 0.95 PU with the additional 60 MVAR of reactive power from the Honolulu 8 and 9 synchronous condensers.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-2 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
100	Archer	125	123	154	72	244	30	135	-7	135	-43	135	-78	135	-104	135	-125	135	-145
120	Halawa	125	106	154	53	154	4	154	-44	154	-91	154	-137	154	-174	154	-207	154	-238
150	Koolau	125	54	125	11	125	-32	125	-70	316	-102	203	-126	203	-143	203	-161	203	-177
170	Pukele	125	39	125	8	125	-23	125	-52	125	-79	316	-102	316	-121	203	-136	203	-151

Table O-63. Summary of Results 2021 QV Mitigation Analysis

Table O-63 shows the results of the QV analysis with the Honolulu 8 and 9 synchronous condensers. The unit commitment and dispatch in conjunction with the Honolulu 8 and 9 synchronous condensers are able to meet the reactive power requirements of the system under N-2 contingencies.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours that were selected from the production simulation data to represent a typical condition and a boundary condition.

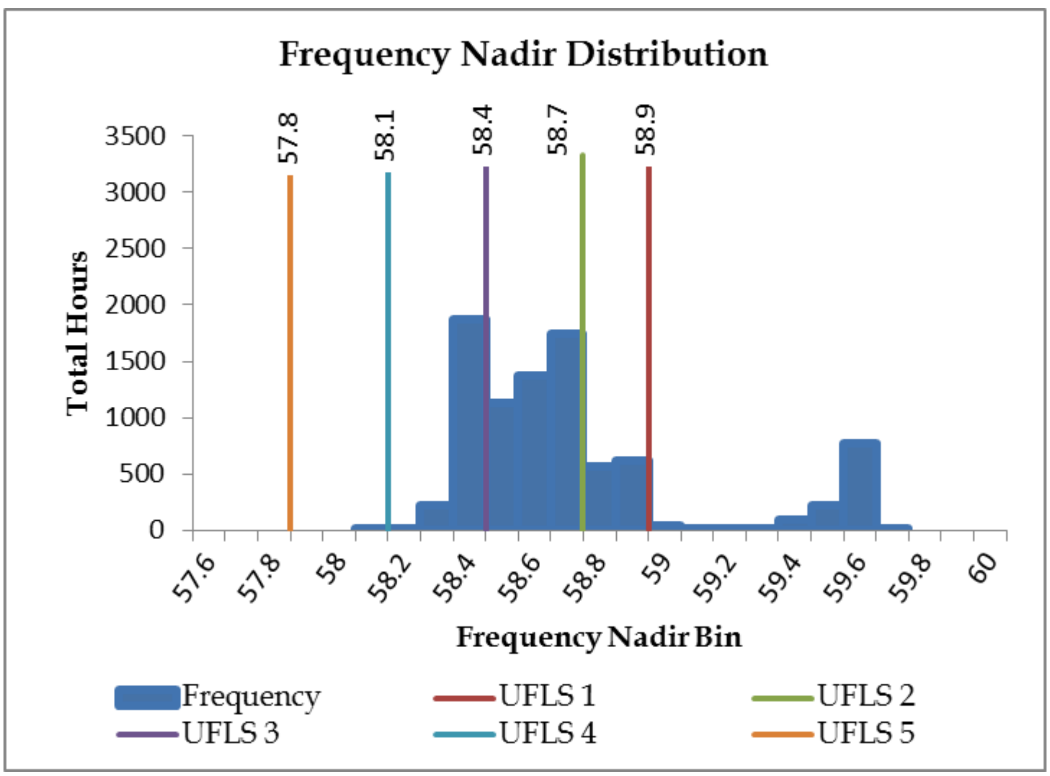

Figure O-145. Frequency Nadir Histogram 2021

Figure O-145 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1871 hours was 10:00 AM on Tuesday, February 23. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 18 hours was 3:00 AM on Sunday, March 14. The frequency nadir range for the boundary hour is 58.0 – 58.1 Hz that requires four blocks of UFLS to stabilize system frequency.

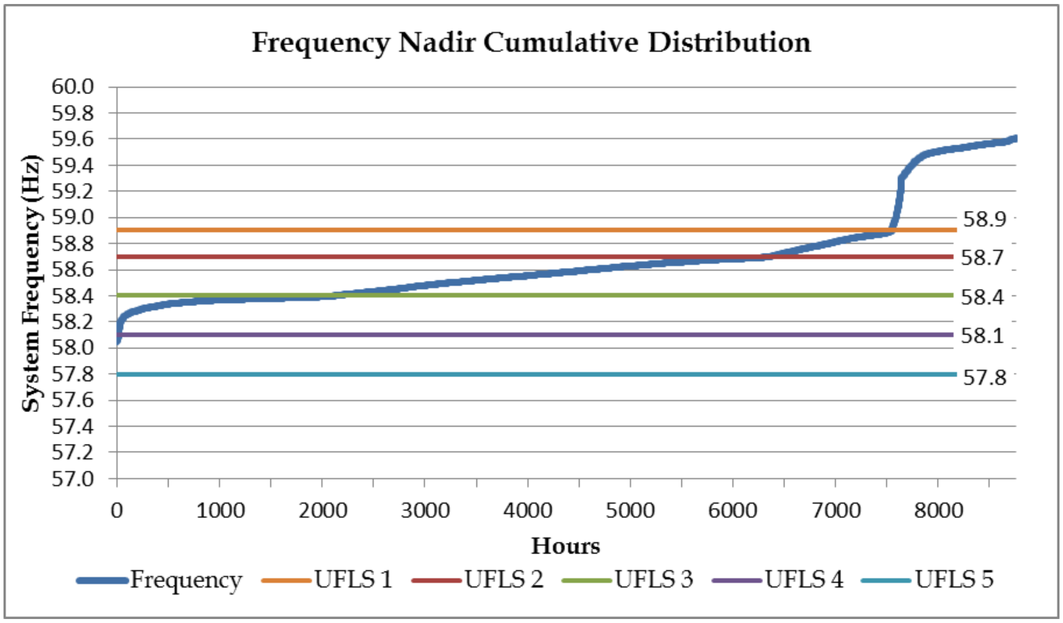

Figure O-146. Frequency Nadir Duration Curve 2021

Figure O-146 shows the frequency nadir duration curve for 2021. The system is at risk of UFLS for 7546 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Tue 2/23/21 Hour 10			DR - AES Trip Boundary Sun 3/14/21 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	62.7	21.3	33.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	14.9	5.1	4.9	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	32.1	54.1	8.4			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4	41.3	44.0	17.7
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261				25.0	29.5	1.5
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	25.0	61.2	0.9	25.0	61.2	0.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						30			53		
-Kahuku	30	0						1			11		
-Kawailoa	69	0						12			13		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						4			2		
DG-PV	712	0						321			0		
Station PV	463	0						272			0		
Total Kinetic Energy									4087			3586	
Total Load									1066			576	
Total Thermal Generation									444			523	
Total Renewable Generation									622			53	
Total Generation									1066			576	
Excess Generation									0			0	
Total Up Regulation									339			146	
Total Down Regulation									188			296	
Total FFR2 Capacity									47			32	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		32.7	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		96.1	60.5Hz Output		0.0

Table O-64. Unit Commitment and Dispatch 2021

Table O-64 shows the unit commitment and dispatch for the typical hour (2/23/21, 10:00 AM) and boundary hour (3/14/21, 3:00 AM).

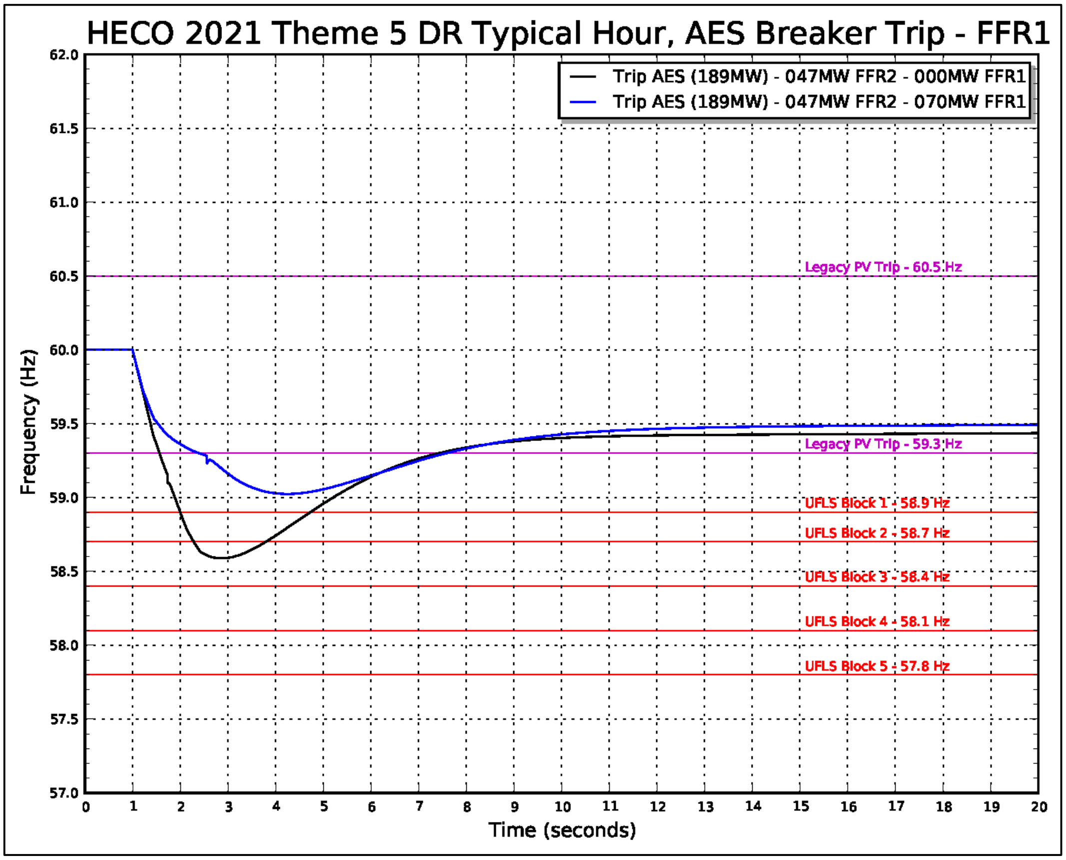

Figure O-147. Frequency Response Profile FFR1 Typical Hour

Figure O-147 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 4087 MW-sec, the capacity of FFR2 is 47 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 32.7 MW. With no FFR1, the frequency nadir is 58.6 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 47 MW of FFR2.

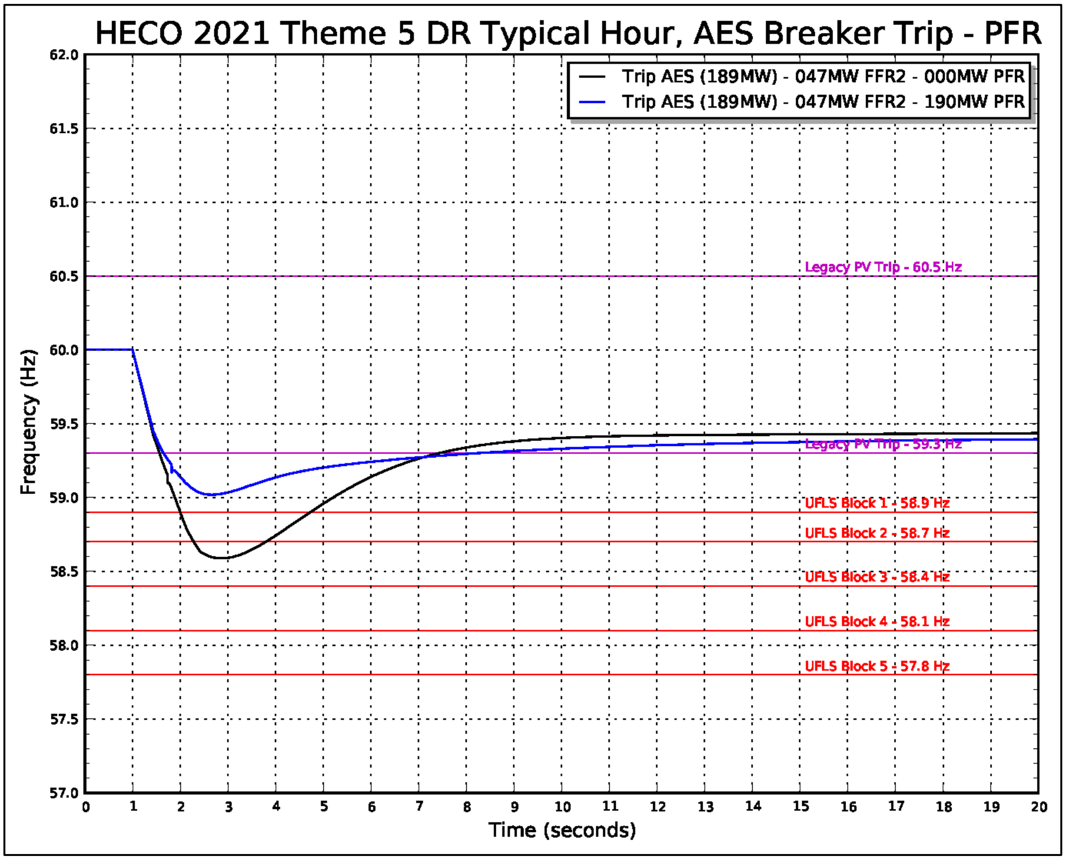

Figure O-148. Frequency Response Profile PFR Typical Hour

Figure O-148 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 190 MW. This is in addition to the 47 MW of FFR2 and 339 MW of upward regulation from thermal generation.

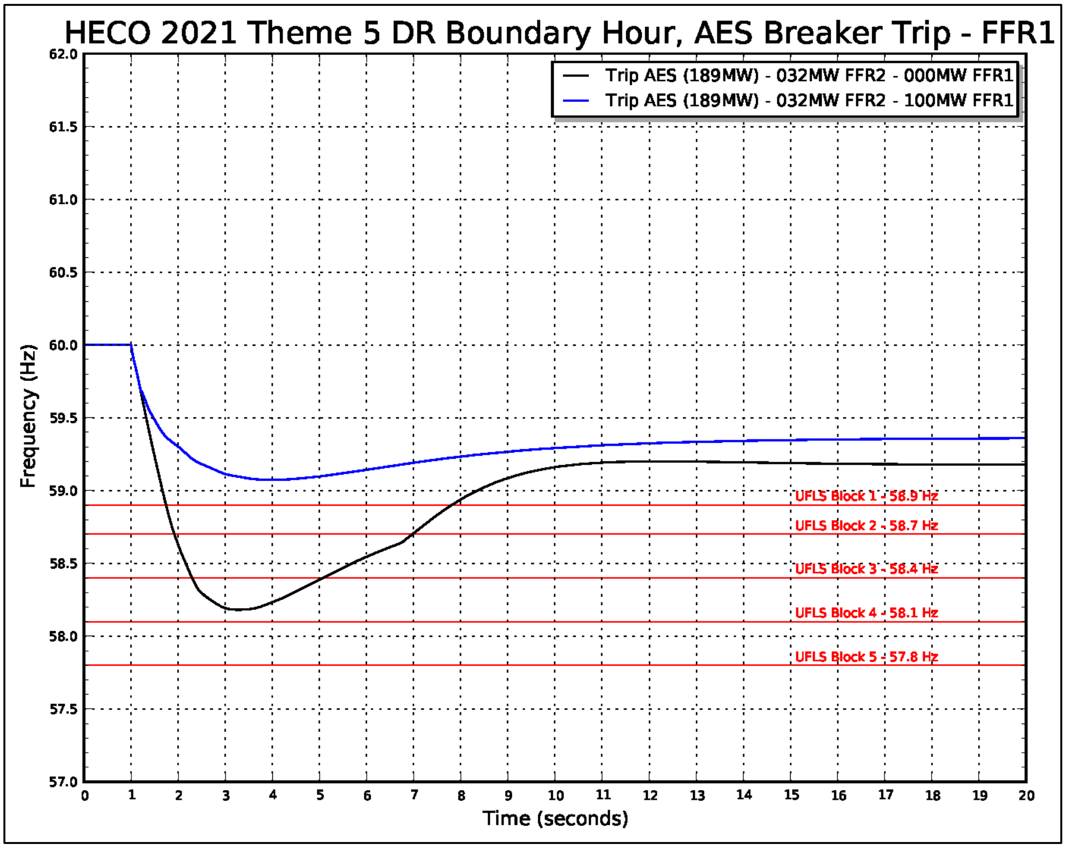

Figure O-149. Frequency Response Profile FFR1 Boundary Hour

Figure O-149 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3586 MW-sec and the capacity of FFR2 is 32 MW. With no FFR1, the frequency nadir is 58.2 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 32 MW of FFR2.

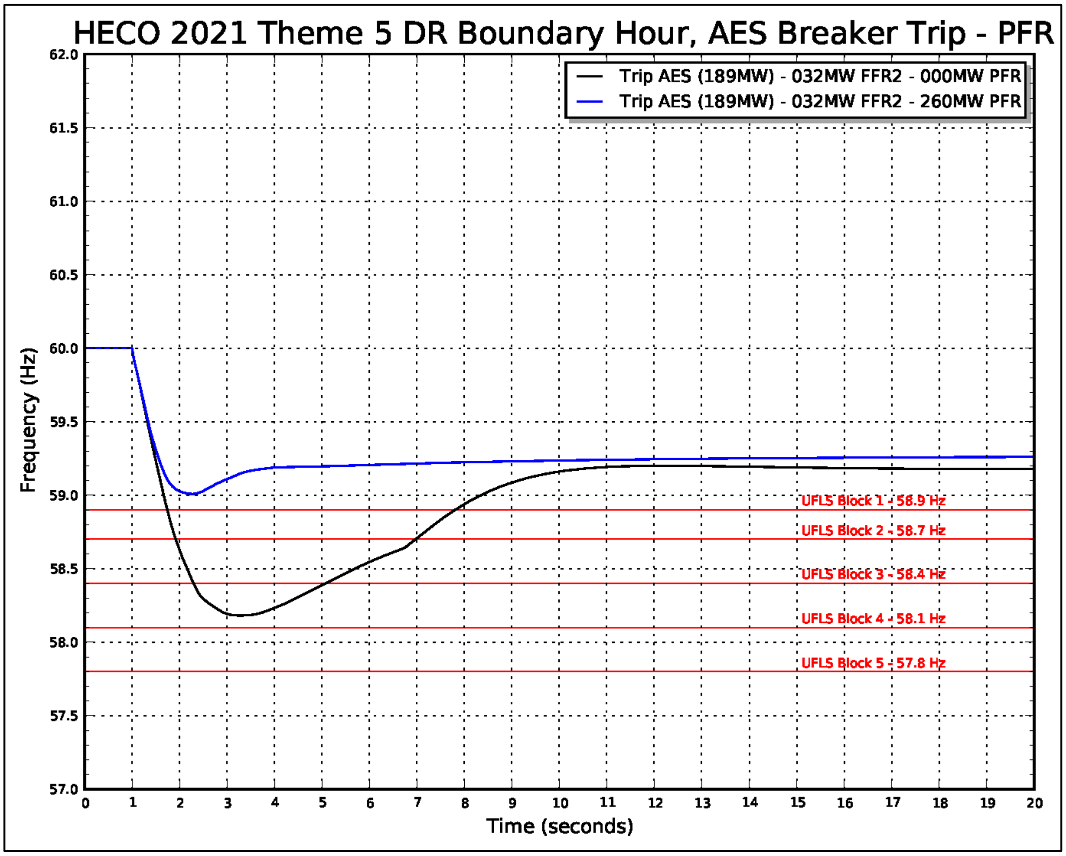

Figure O-150. Frequency Response Profile PFR Boundary Hour

Figure O-150 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 32 MW of FFR2 and 146 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip Typical Tue 2/23/21 Hour 10			DR - K5 Trip Boundary Sun 3/14/21 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615	104.0	85.0	41.0	104.0	85.0	41.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	62.7	21.3	33.7	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	14.9	5.1	4.9	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591				84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	25.0	57.2	1.2			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	32.1	54.1	8.4			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357				41.3	44.0	17.7
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						30			53		
-Kahuku	30	0						1			11		
-Kawailoa	69	0						12			13		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						4			2		
DG-PV	712	0						321			0		
Station PV	463	0						272			0		
Total Kinetic Energy								3996			3591		
Total Load								1066			576		
Total Thermal Generation								444			523		
Total Renewable Generation								622			53		
Total Generation								1066			576		
Excess Generation								0			0		
Total Up Regulation								303			140		
Total Down Regulation								214			322		
Total FFR2 Capacity								47			32		
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		32.7	59.3Hz Output		0.0
	60.5Hz Capacity		215.9					60.5Hz Output		96.1	60.5Hz Output		0.0

Table O-65. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-65 shows the unit commitment and dispatch for the typical hour (2/23/21, 10:00 AM) and boundary hour (3/14/21, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

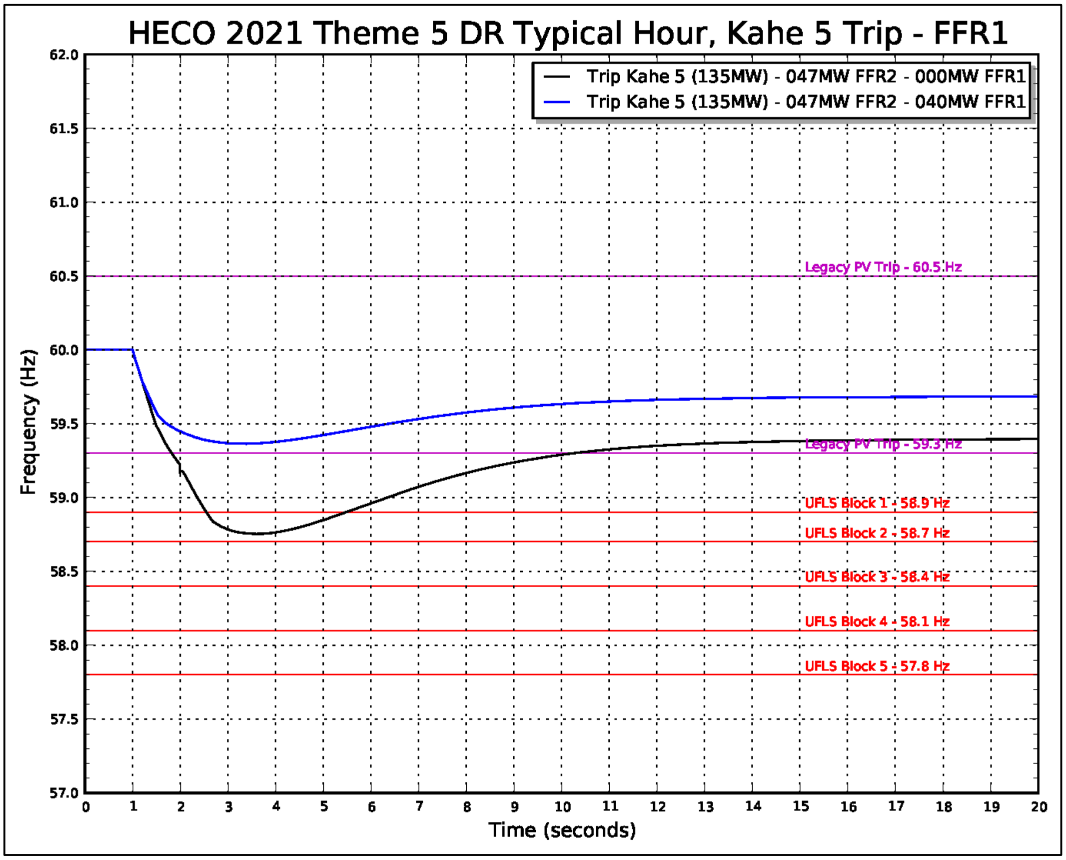

Figure O-151. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-151 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3996 MW-sec, the capacity of FFR2 is 47 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 33 MW. With no additional FFR, the frequency nadir is 58.8 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 40 MW. This is in addition to the 47 MW of FFR2.

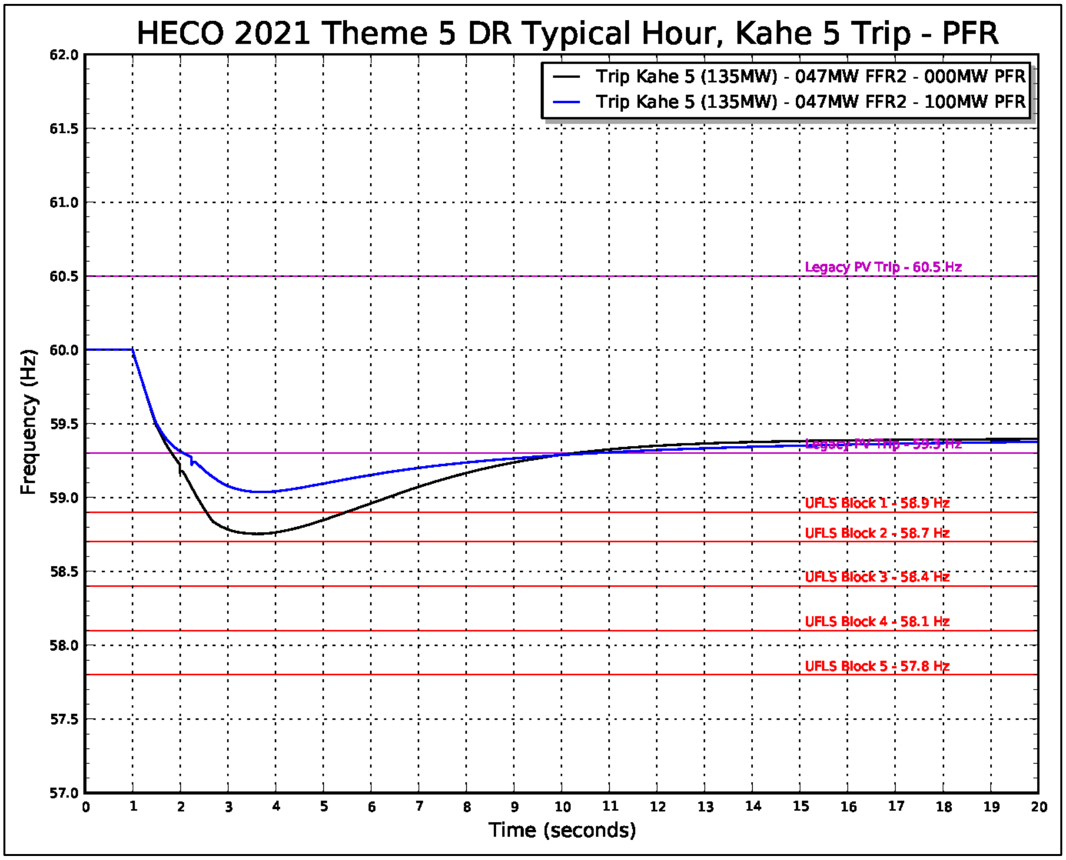

Figure O-152. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-152 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 47 MW of FFR2 and 303 MW of upward regulation from thermal generation.

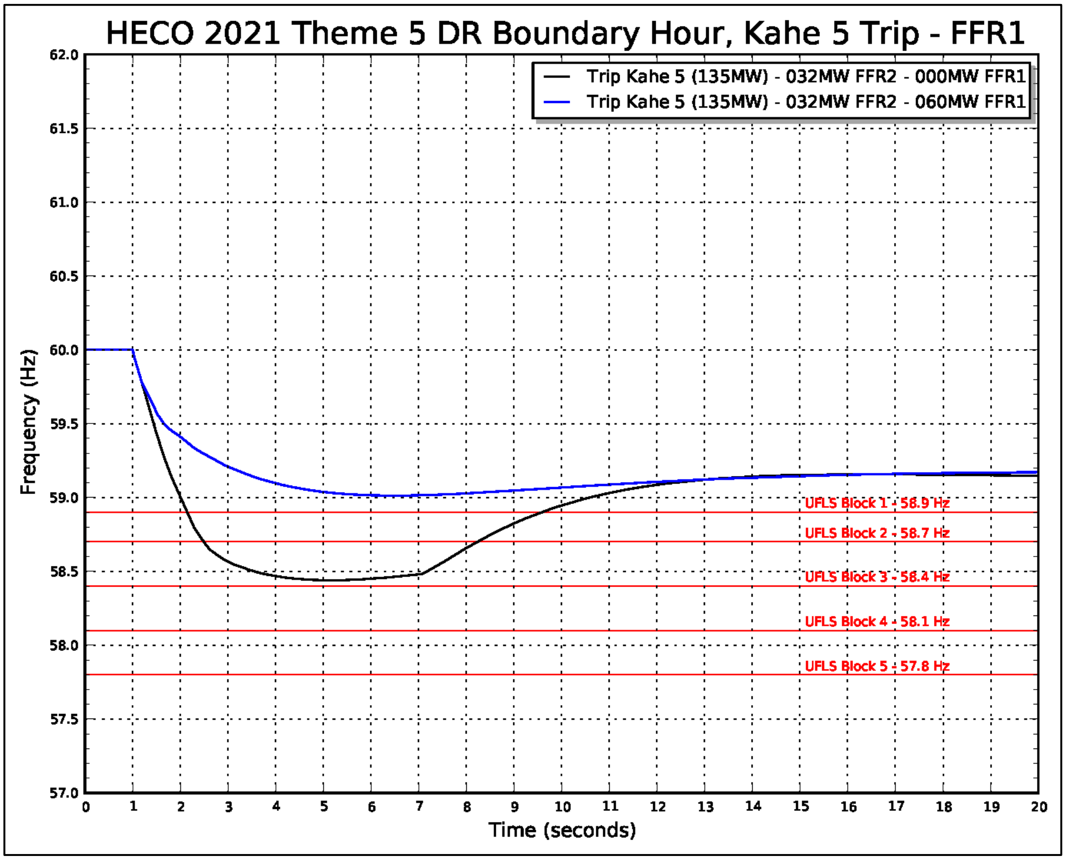

Figure O-153. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-153 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3591 MW-sec and the capacity of FFR2 is 32 MW. With no additional FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 32 MW of FFR2.

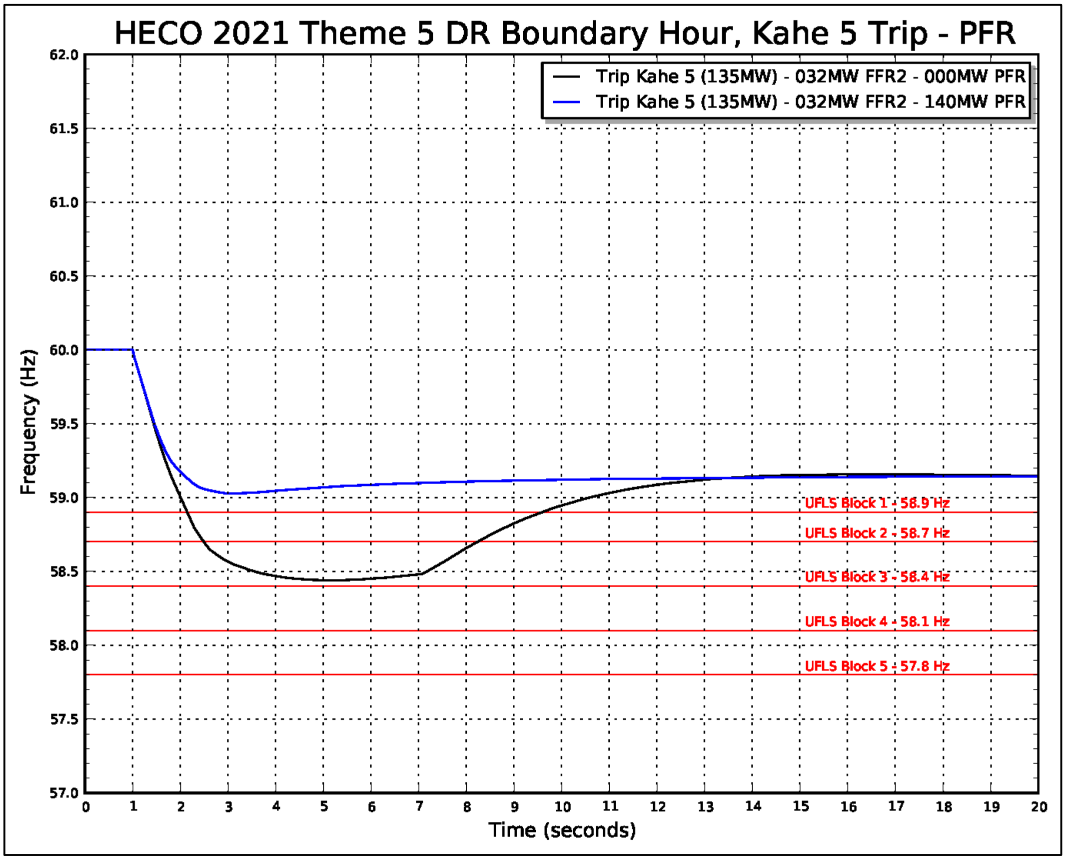

Figure O-154. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-154 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 140 MW. This is in addition to the 32 MW of FFR2 and 140 MW of upward regulation from thermal generation.

138 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

Unit	Unit Ratings							DR - Fault Sun 7/11/21 Hour 13		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	25.0	21.0	0.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0
AES	189.0	63.0			2.57	239.0	615	63.0	126.0	0.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	52.5	31.5	23.5
Kalaeloa ST	40.0	10.0			4.70	61.1	287	12.5	7.5	2.5
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	25.0	61.2	1.3
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	25.0	60.3	1.4
Kahe 5	134.6	21.0			4.36	158.8	692			
Kahe 6	133.8	40.0			4.36	158.8	692			
Waiau 3	47.0	23.7			4.51	57.5	259			
Waiau 4	46.5	23.5			4.51	57.5	259			
Waiau 5	54.5	23.5			4.07	64.0	261	25.0	29.5	1.5
Waiau 6	53.7	23.8			4.00	64.0	256			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426			
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426			
Waiau 9	52.9	5.9			7.84	57.0	447			
Waiau 10	49.9	5.9			7.84	57.0	447			
CIP1	112.2	41.2			4.72	162.0	765			
Schofield 1	8.0	2.0			0.99	10.9	11			
Schofield 2	8.0	2.0			0.99	10.9	11			
Schofield 3	8.0	2.0			0.99	10.9	11			
Schofield 4	8.0	2.0			0.99	10.9	11			
Schofield 5	8.0	2.0			0.99	10.9	11			
Schofield 6	8.0	2.0			0.99	10.9	11			
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.	
Total Wind	163	0						54		
-Kahuku	30	0						11		
-Kawailoa	69	0						19		
-Na Pua Makani	24	0						21		
-CBRE Wind	10	0						3		
DG-PV	712	0						533		
Station PV	463	0						273		
Total Kinetic Energy									3069	
Total Load									1098	
Total Thermal Generation									238	
Total Renewable Generation									860	
Total Generation									1098	
Excess Generation									0	
Total Up Regulation									350	
Total Down Regulation									30	
Total FFR2 Capacity									53	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		54.5
	60.5Hz Capacity			215.9				60.5Hz Output		160.2

Table O-66. Unit Commitment and Dispatch Fault Analysis 2021

Table O-66 shows the unit commitment and dispatch for the fault analysis. The capacity of inverter-based PV generation is 806 MW and the capacity of demand response is 53 MW.

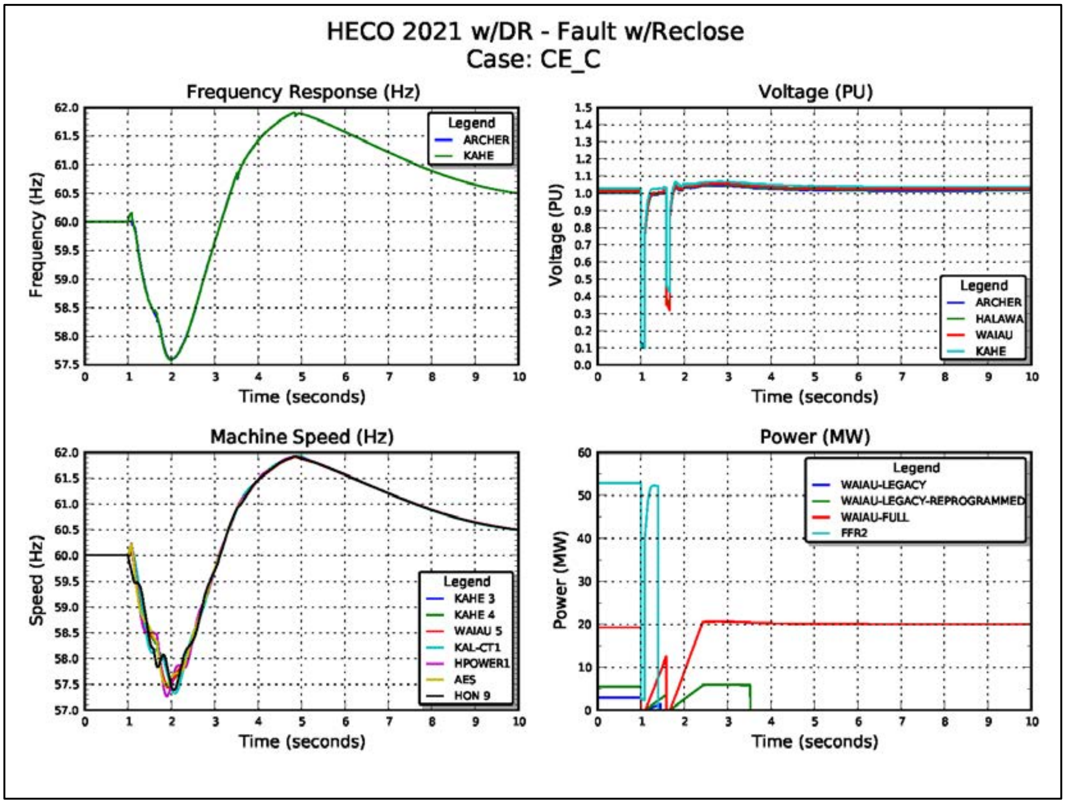

Figure O-155. System Performance for Normally Cleared Fault

Figure O-155 shows the system performance for a normally cleared fault on the CEIP-Ewa Nui circuit. System voltage is suppressed below the 0.5 PU threshold where the 806 MW of inverter-based generation momentarily drops to zero, driving system frequency to 57.6 Hz. System voltage is restored within 0.5 seconds so some DG-PV generation is restored. The aggregate response from synchronous units, the restoration of DG-PV generation, five blocks of UFLS, and 53 MW of FFR2 is able to stabilize system frequency but eventually the response over-compensates and drives the frequency apex above 61.0 Hz, tripping legacy PV. The plot at the bottom right shows the response of DG-PV at Waiau that is indicative of all inverter-based generation on the system.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to bring the system into compliance with TPL-001.

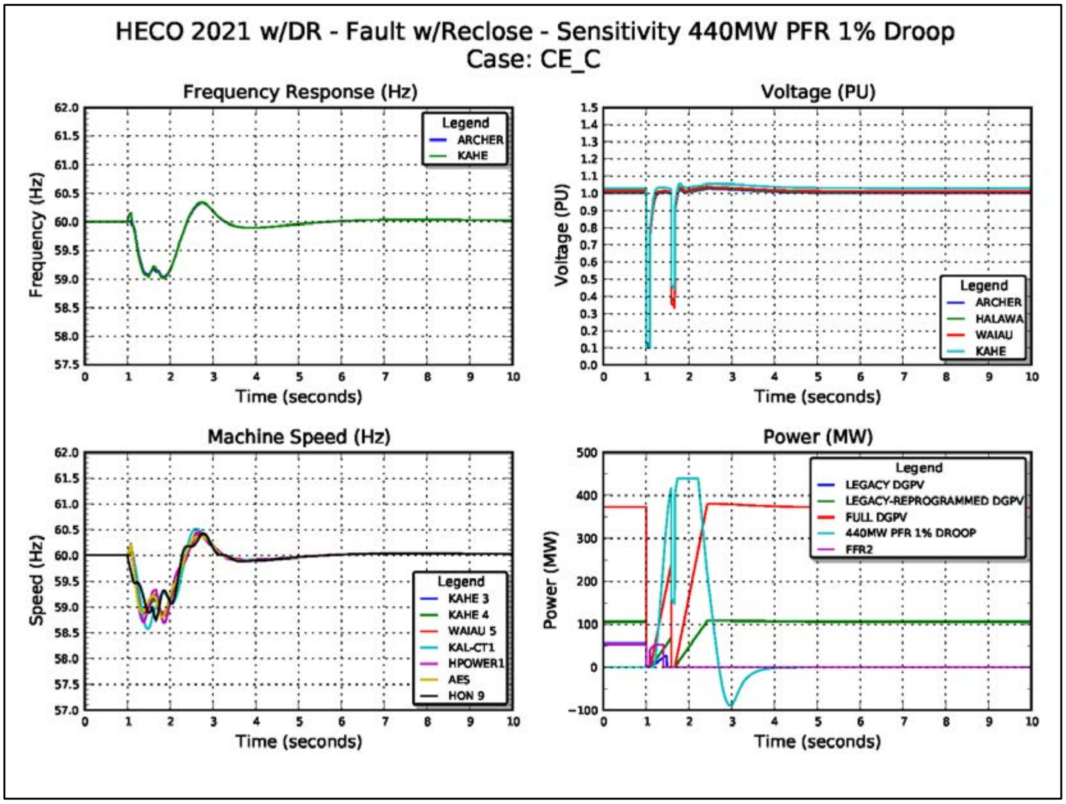

Figure O-156. System Performance Sensitivity Analysis 440 MW PFR

Figure O-156 shows system performance with the addition of 440 MW of PFR at 1% droop response. For the purpose of this analysis, a 440 MW BESS was located at Halawa Substation.

The plot at the bottom right shows the frequency response of DG-PV and the BESS. The aggregate response from synchronous units, 440 MW PFR, and the restoration of DG-PV generation brings the system into compliance with TPL-001.

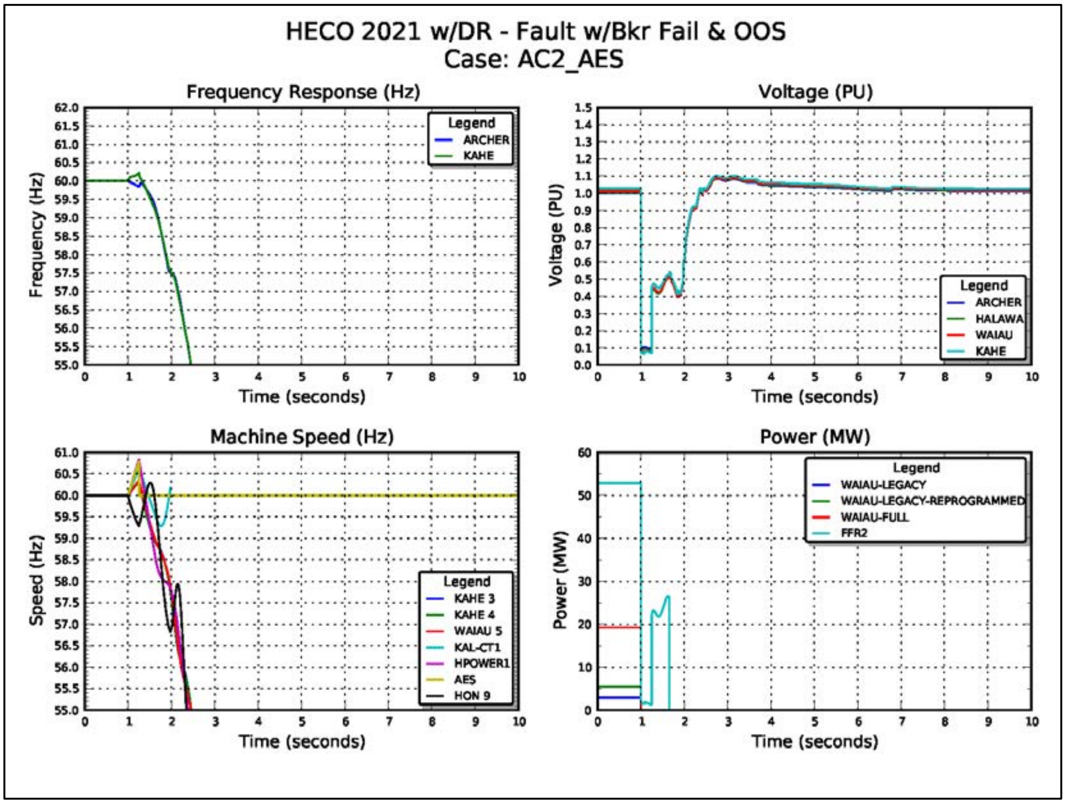

Figure O-157. System Performance for Breaker Failure Analysis

Figure O-157 shows four plots that illustrate system performance for a fault on the AES-CEIP 2 circuit and BKR 323 fails to operate. A breaker failure initiates the backup protection scheme to clear the fault, isolating the AES bus and tripping 63 MW. System voltage is suppressed below the 0.5 PU voltage ride-through setting for longer than 0.5 seconds, causing 806 MW of inverter-based generation to trip offline. The net loss of generation contingency is 869 MW, driving system frequency below 56.0 Hz so the remaining synchronous generators trip offline on under frequency protection. The BKR 323 failure is the only simulation that resulted in system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to stabilize the system.

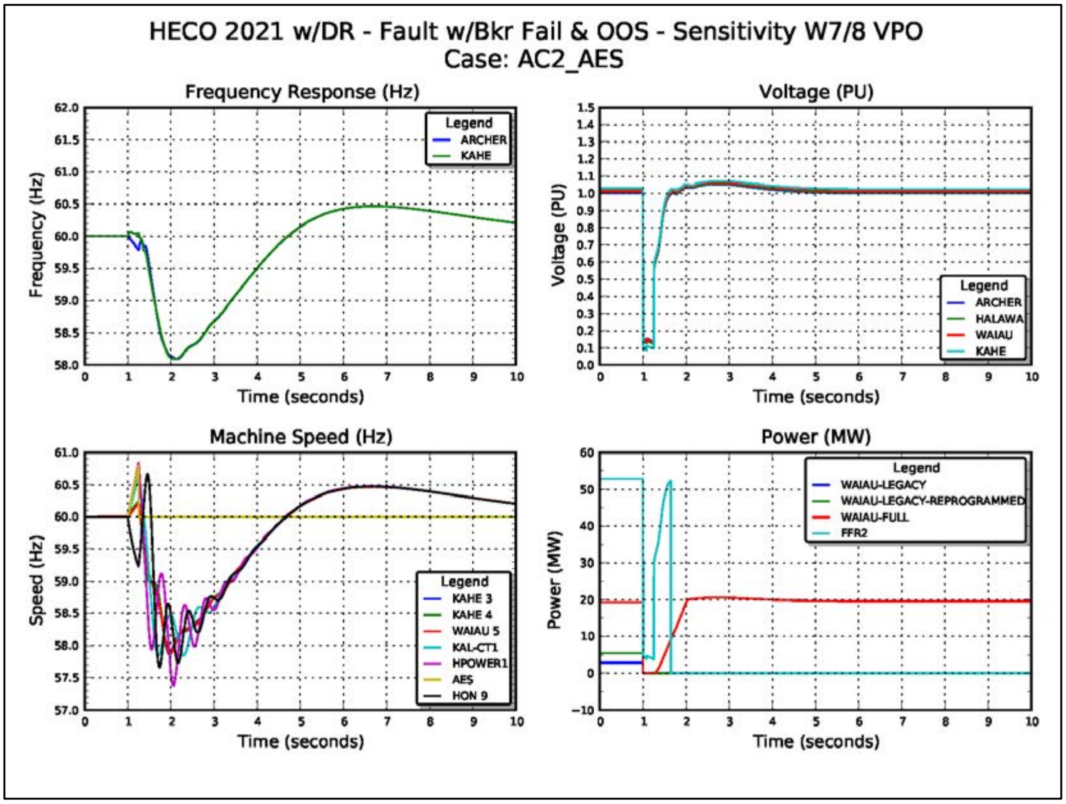

Figure O-158. System Performance Sensitivity Analysis VPO Units

Figure O-158 shows system performance with Waiau Units 7 and 8 operating in VPO. The aggregate response from synchronous generators, restoration of full ride-through DG-PV, and four blocks of UFLS are required to stabilize system frequency. With additional synchronous units at Waiau, system voltage is momentarily suppressed but recovers above the 0.5 PU threshold before the 0.5 second trip setting so generation from full ride-through inverters is restored, arresting frequency decay at 58.0 Hz. The system is stable but is not in compliance with TPL-001.

2021 138 kV Fault Analysis						
Circuit Outage	Bus Fault	Bkr Fail	BFTD	2nd Outage	Fault Hour Condition	Waiau 7/8 VPO Mitigation
AES-CEIP 1	AES	320	15	AES-HP	Stable	Stable
AES-HP	AES	320	15	AES-CEIP 1	Stable	Stable
AES-CEIP 2	AES	323	15	AES Gen	Unstable	Stable
AES-Kalaeloa	AES	456	15	CIP Gen	Stable	Stable
AES-CEIP 1	CEIP	276	18	Kahe-CEIP 2	Stable	Stable
Kahe-CEIP 2	CEIP	276	18	AES-CEIP 1	Stable	Stable
AES-CEIP 2	CEIP	279	18	CEIP-Ewa Nui	Stable	Stable
CEIP-Ewa Nui	CEIP	279	18	AES-CEIP 2	Stable	Stable
CEIP-Ewa Nui	EWA	384	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Ewa Nui 2	EWA	384	18	CEIP-Ewa Nui	Stable	Stable
Kalaeloa-Ewa Nui	EWA	387	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 1	EWA	387	18	Kalaeloa-Ewa Nui	Stable	Stable
Halawa-Iwilei	HLWA	158	18	Halawa-Makalapa	Stable	Stable
Halawa-Makalapa	HLWA	158	18	Halawa-Iwilei	Stable	Stable
Halawa-School	HLWA	161	18	Kahe-Halawa 1	Stable	Stable
Kahe-Halawa 1	HLWA	161	18	Halawa-School	Stable	Stable
Halawa-Koolau	HLWA	176	18	Kahe-Halawa 2	Stable	Stable
Kahe-Halawa 2	HLWA	176	18	Halawa-Koolau	Stable	Stable
Kahe-Wahiawa	KAHE	129	18	K1 Gen	Stable	Stable
Kahe-Halawa 2	KAHE	132	18	K2 Gen	Stable	Stable
Kahe-Halawa 1	KAHE	168	18	K3 Gen	Stable	Stable
Kahe-Waiau	KAHE	171	18	K4 Gen	Stable	Stable
Kahe-CEIP 2	KAHE	246	18	K5 Gen	Stable	Stable
Kahe-CEIP 1	KAHE	249	18	K6 Gen	Stable	Stable
Kalaeloa-Ewa Nui	KPLP	310	18	Kal2 Gen	Stable	Stable
AES-Kalaeloa	KPLP	313	18	Kal1 Gen	Stable	Stable
Waiau-Makalapa 1	MKLPA	260	18	Makalapa Tsf 3	Stable	Stable
Halawa-Makalapa	MKLPA	263	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	MKLPA	263	18	Halawa-Makalapa	Stable	Stable
Makalapa-Airport	MKLPA	266	18	Makalapa Tsf 1	Stable	Stable
Kahe-Waiau	WAIAU	102	18	W5 Gen	Stable	Stable
Waiau-Koolau 2	WAIAU	105	18	W6 Gen	Stable	Stable
Waiau-Wahiawa	WAIAU	108	18	W8 Gen	Stable	Stable
Waiau-Koolau 1	WAIAU	111	18	W7 Gen	Stable	Stable
Waiau-Ewa Nui 1	WAIAU	179	18	Waiau-Makalapa 2	Stable	Stable
Waiau-Makalapa 2	WAIAU	179	18	Waiau-Ewa Nui 1	Stable	Stable
Waiau-Ewa Nui 2	WAIAU	302	18	Waiau-Makalapa 1	Stable	Stable
Waiau-Makalapa 1	WAIAU	302	18	Waiau-Ewa Nui 2	Stable	Stable
Waiau-Wahiawa	WHWA	145	18	Wahiawa Tsf 3	Stable	Stable

Table O-67. Summary of Results Breaker Failure Analysis

Table O-67 shows the results for the breaker failure analysis. Committing Waiau Units 7 and 8 in VPO can help stabilize system frequency but multiple blocks of UFLS was also required.

The system requires 440 MW of PFR at 1% droop response to meet the requirements of TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2022

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

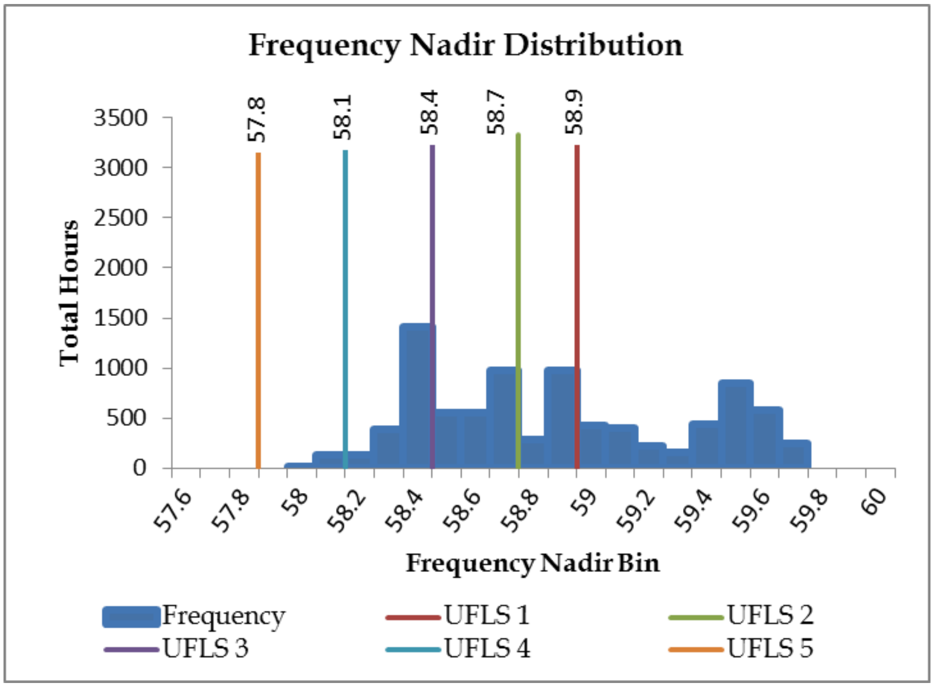

Figure O-159. Frequency Nadir Histogram 2022

Figure O-159 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1412 hours was 8:00 AM on Friday, August 5. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the distribution of one hour was 3:00 AM on Monday, March 21. The frequency nadir range for the boundary hour is 57.9 – 58.0 Hz that requires four blocks of UFLS to stabilize system frequency.

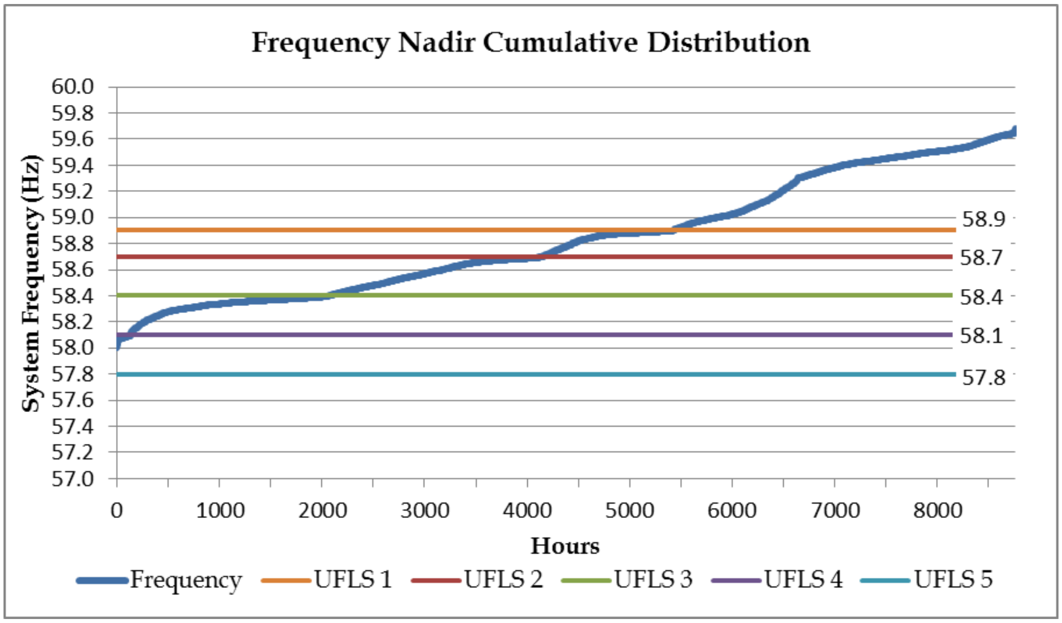

Figure O-160. Frequency Nadir Duration Curve 2022

Figure O-160 shows the frequency nadir duration curve for 2021. The system is at risk of UFLS for5424 hours of the year.

Unit	Unit Ratings							DR - AES Trip Typical Fri 8/5/22 Hour 8			DR - AES Trip Boundary Mon 3/21/22 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615	189.0	0.0	126.0	189.0	0.0	126.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	45.4	40.8	21.7			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	41.7	43.6	18.1			
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426				43.3	40.0	19.5
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	30.2	56.0	6.1	44.0	42.2	19.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1	14.6	2.2	7.9
JBPHH 2	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1			
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						40			59		
-Kahuku	30	0						13			13		
-Kawailoa	69	0						19			17		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						2			2		
DG-PV	729	0						91			0		
Station PV	543	0						56			0		
Total Kinetic Energy									3869			3416	
Total Load									804			593	
Total Thermal Generation									616			534	
Total Renewable Generation									187			59	
Total Generation									804			593	
Excess Generation									0			0	
Total Up Regulation									140			95	
Total Down Regulation									366			323	
Total FFR2 Capacity									38			33	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		9.5	59.3Hz Output		0.0
	60.5Hz Capacity		215.9					60.5Hz Output		27.8	60.5Hz Output		0.0

Table O-68. Unit Commitment and Dispatch 2022

Table O-68 shows the unit commitment and dispatch for the typical hour (8/5/22, 8:00 AM) and boundary hour (3/21/22, 3:00 AM).

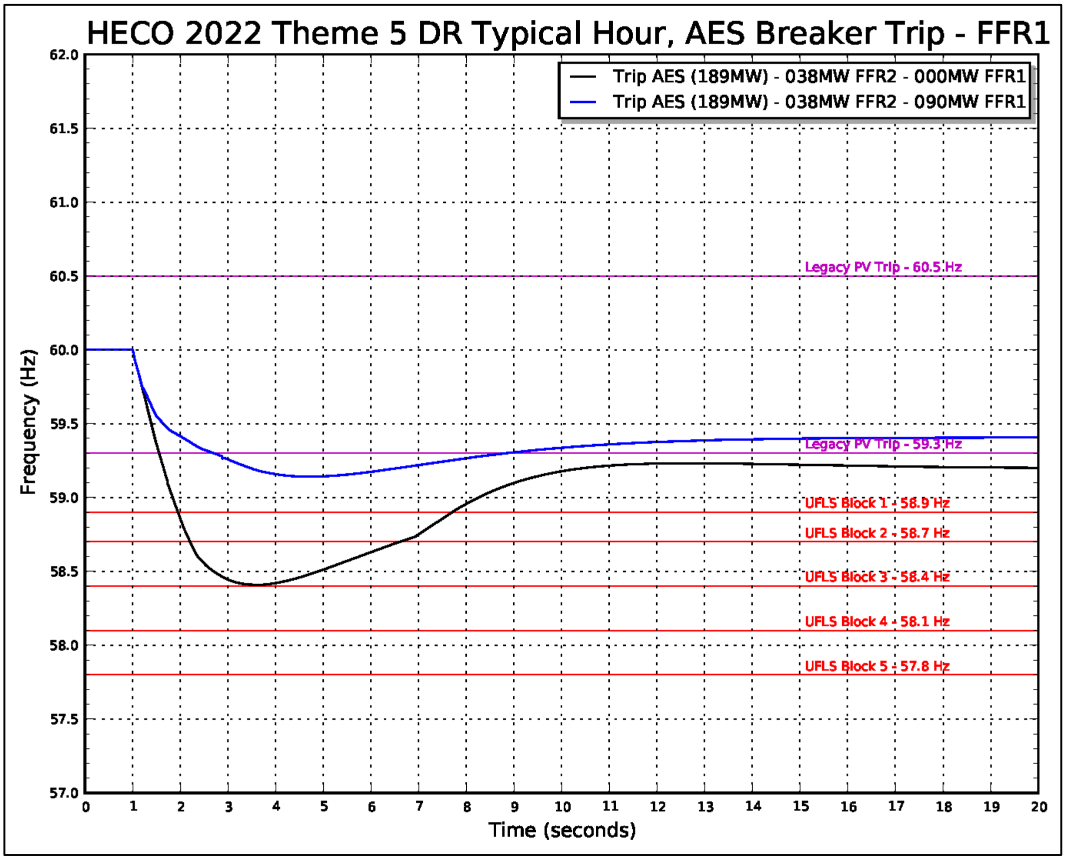

Figure O-161. Frequency Response Profile FFR1 Typical Hour

Figure O-161 shows the frequency response profile for an AES trip at 189 MW for a typical hour. System kinetic energy is 3869 MW-sec, the capacity of FFR2 is 38 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 9.5 MW. With no FFR1, the frequency nadir is 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 38 MW of FFR2.

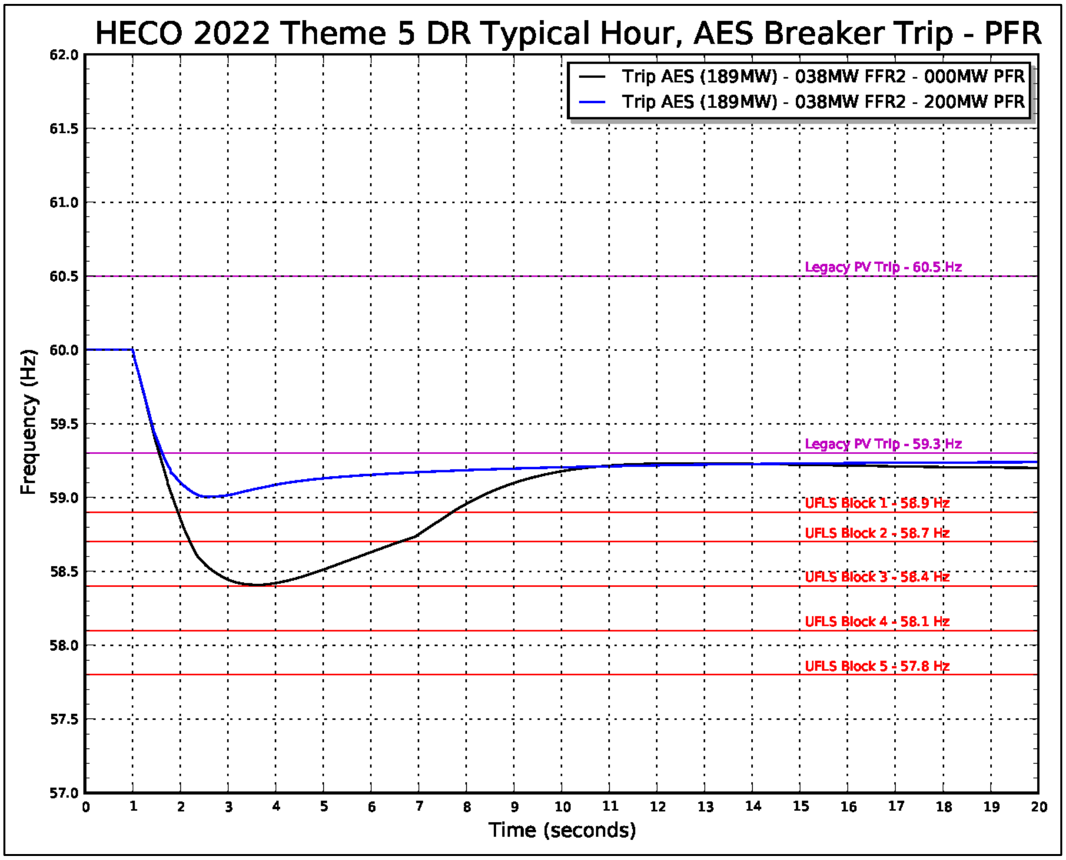

Figure O-162. Frequency Response Profile PFR Typical Hour

Figure O-162 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 38 MW of FFR2 and 140 MW of upward regulation from thermal generation.

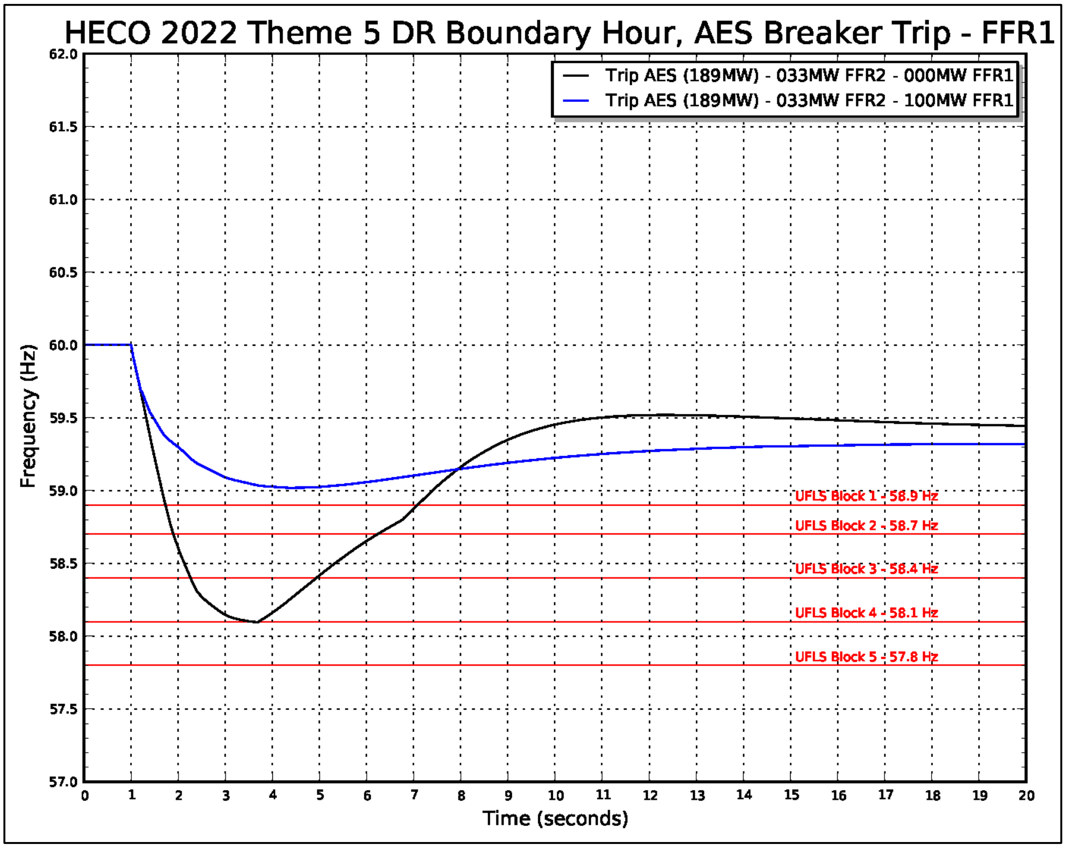

Figure O-163. Frequency Response Profile FFR1 Boundary Hour

Figure O-163 shows the frequency response profile for an AES trip at 189 MW for a boundary hour. System kinetic energy is 3416 MW-sec and the capacity of FFR2 is 33 MW. With no additional FFR, the frequency nadir is 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 100 MW. This is in addition to the 33 MW of FFR2.

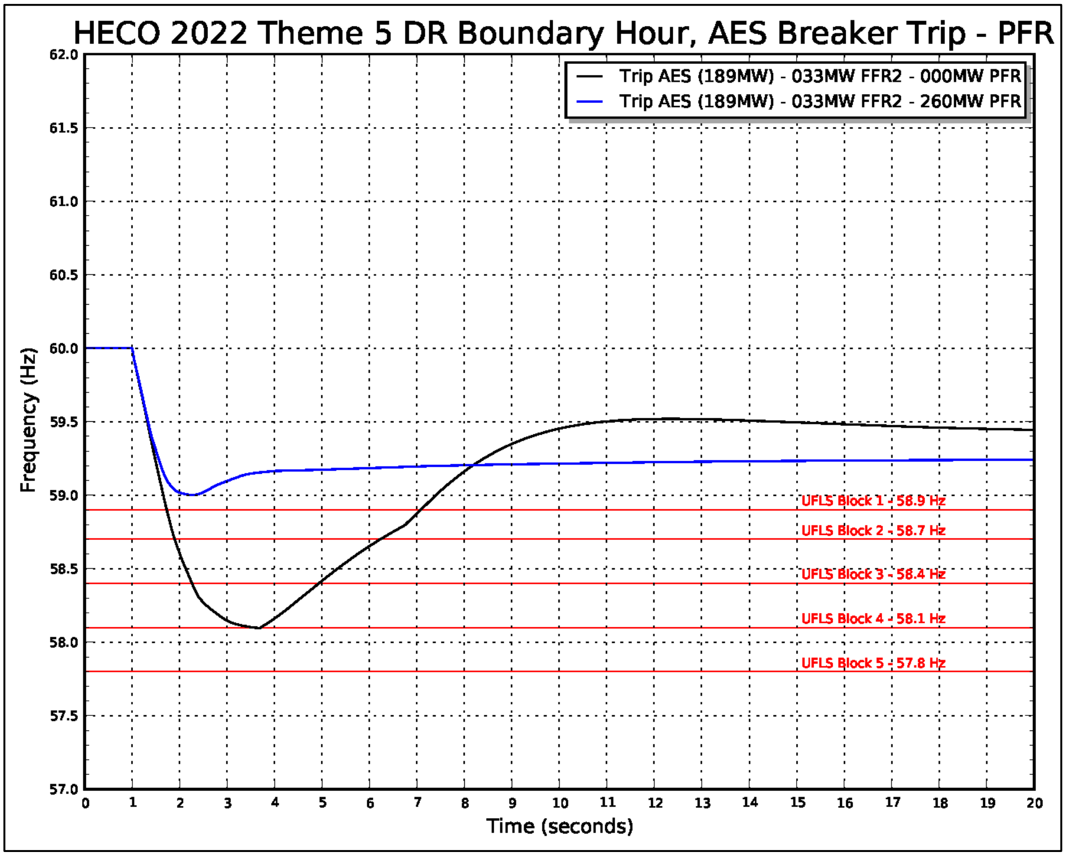

Figure O-164. Frequency Response Profile PFR Boundary Hour

Figure O-164 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 260 MW. This is in addition to the 33 MW of FFR2 and 95 MW of upward regulation from thermal generation.

A sensitivity analysis was performed to determine the frequency response reserve requirements to meet TPL-001 if AES was dispatched to a lower output. The next largest generator contingency is Kahe Unit 5 or Kahe Unit 6 at 135 MW.

Unit	Unit Ratings							DR - K5 Trip Typical Fri 8/5/22 Hour 8			DR - K5 Trip Boundary Mon 3/21/22 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615	134.0	55.0	71.0	112.0	77.0	49.0
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	38.2	48.0	14.1	44.0	42.2	19.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1			
JBPHH 2	16.8	6.7			0.99	21.8	22	16.8	0.0	10.1			
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						40			59		
-Kahuku	30	0						13			13		
-Kawailoa	69	0						19			17		
-Na Pua Makani	24	0						0			21		
-CBRE Wind	10	0						2			2		
DG-PV	729	0						91			0		
Station PV	543	0						56			0		
Total Kinetic Energy									3847			3660	
Total Load									804			593	
Total Thermal Generation									617			534	
Total Renewable Generation									187			59	
Total Generation									804			592	
Excess Generation									0			0	
Total Up Regulation									103			130	
Total Down Regulation									392			332	
Total FFR2 Capacity									38			33	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		9.5	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		27.8	60.5Hz Output		0.0

Table O-69. Unit Commitment and Dispatch Kahe 5 Sensitivity

Table O-69 shows the unit commitment and dispatch for the typical hour (8/5/22, 8:00 AM) and boundary hour (3/21/22, 3:00 AM). Kahe 5 was dispatched to full output to determine the frequency response reserve requirements to bring the system into compliance with TPL-001.

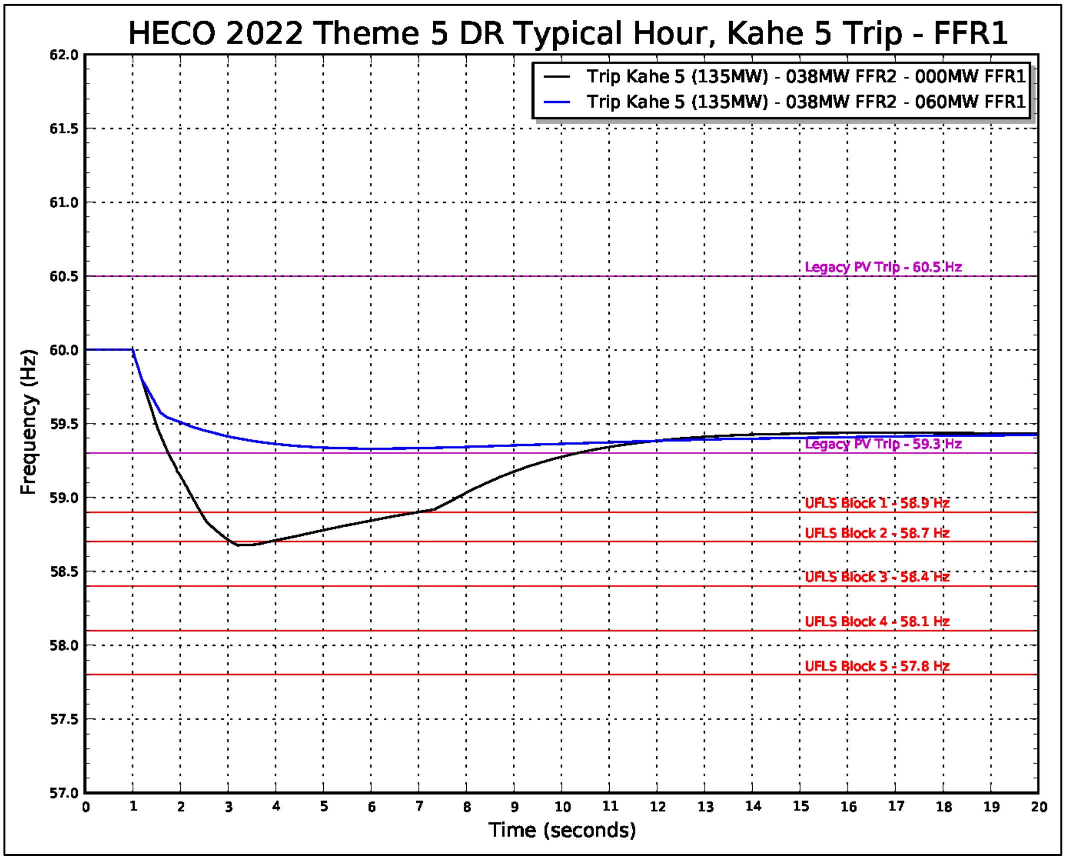

Figure O-165. Frequency Response Profile FFR1 Sensitivity Typical Hour

Figure O-165 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 3847 MW-sec, the capacity of FFR2 is 38 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 9.5 MW. With no FFR1, the frequency nadir breaches 58.7 Hz. Two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 38 MW of FFR2.

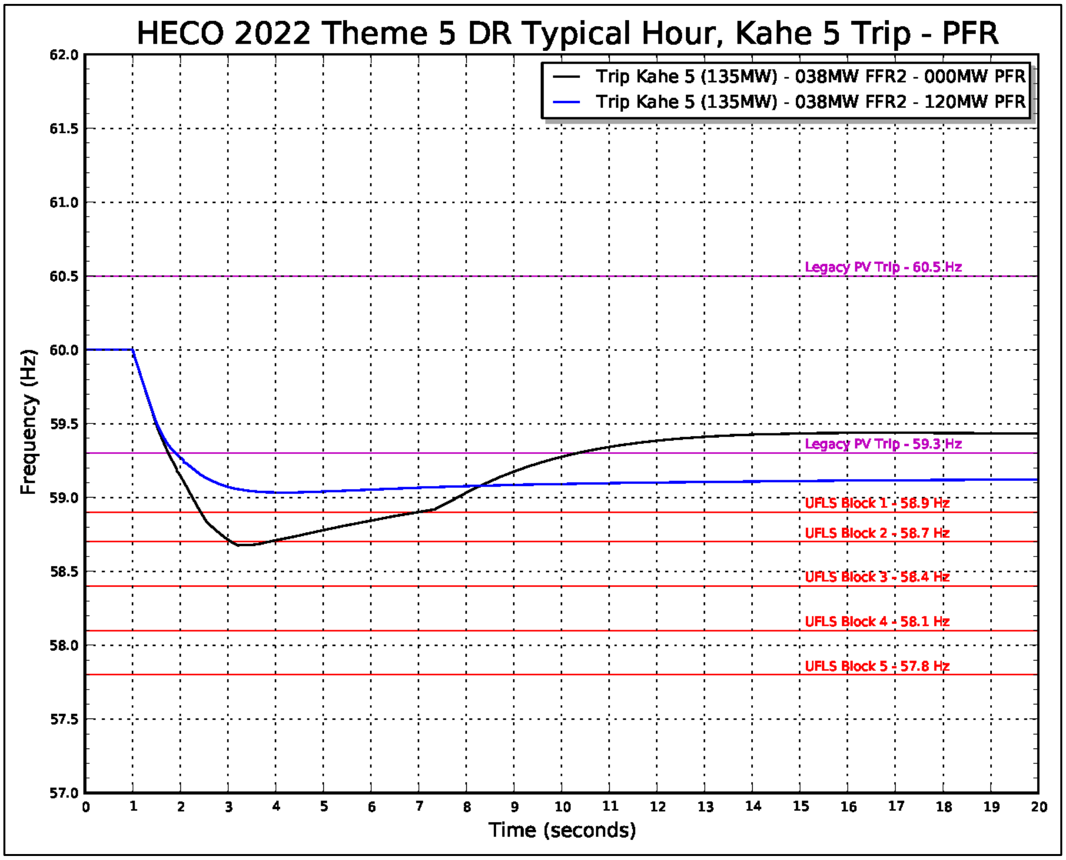

Figure O-166. Frequency Response Profile PFR Sensitivity Typical Hour

Figure O-166 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 120 MW. This is in addition to the 38 MW of FFR2 and 103 MW of upward regulation from thermal generation.

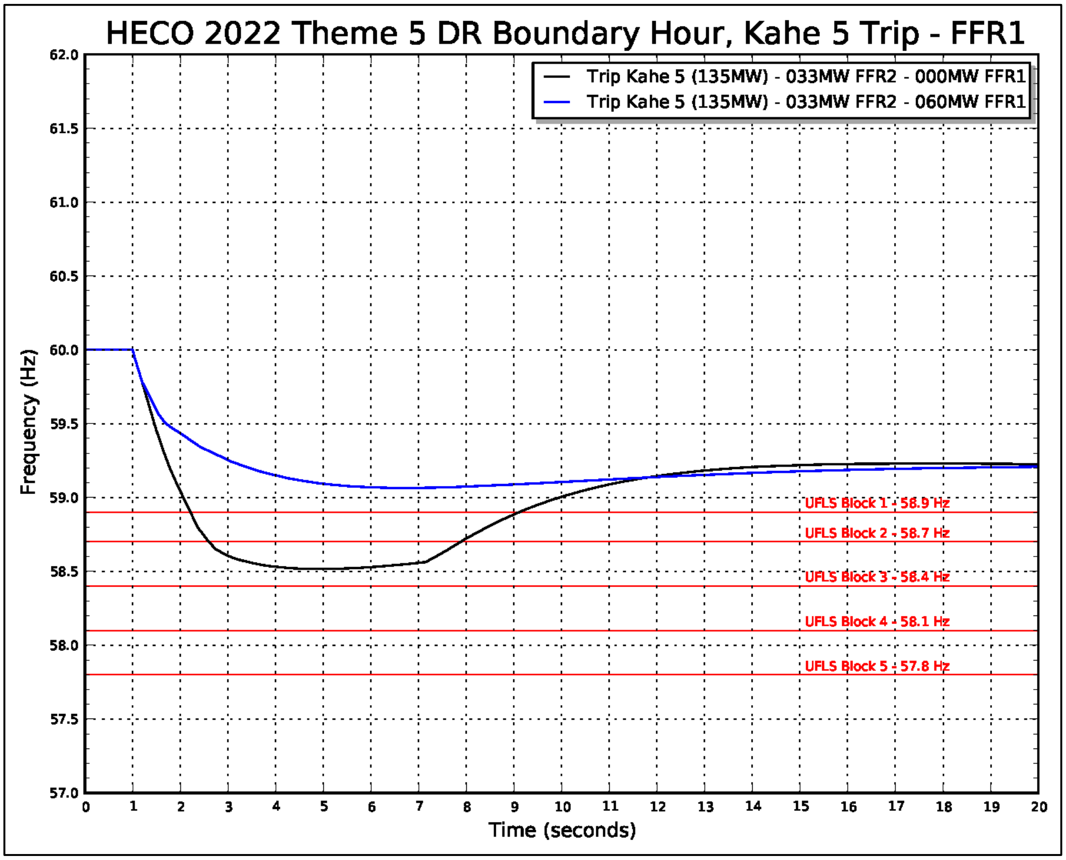

Figure O-167. Frequency Response Profile FFR1 Sensitivity Boundary Hour

Figure O-167 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3660 MW-sec and the capacity of FFR2 is 33 MW. With no FFR1, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 33 MW of FFR2.

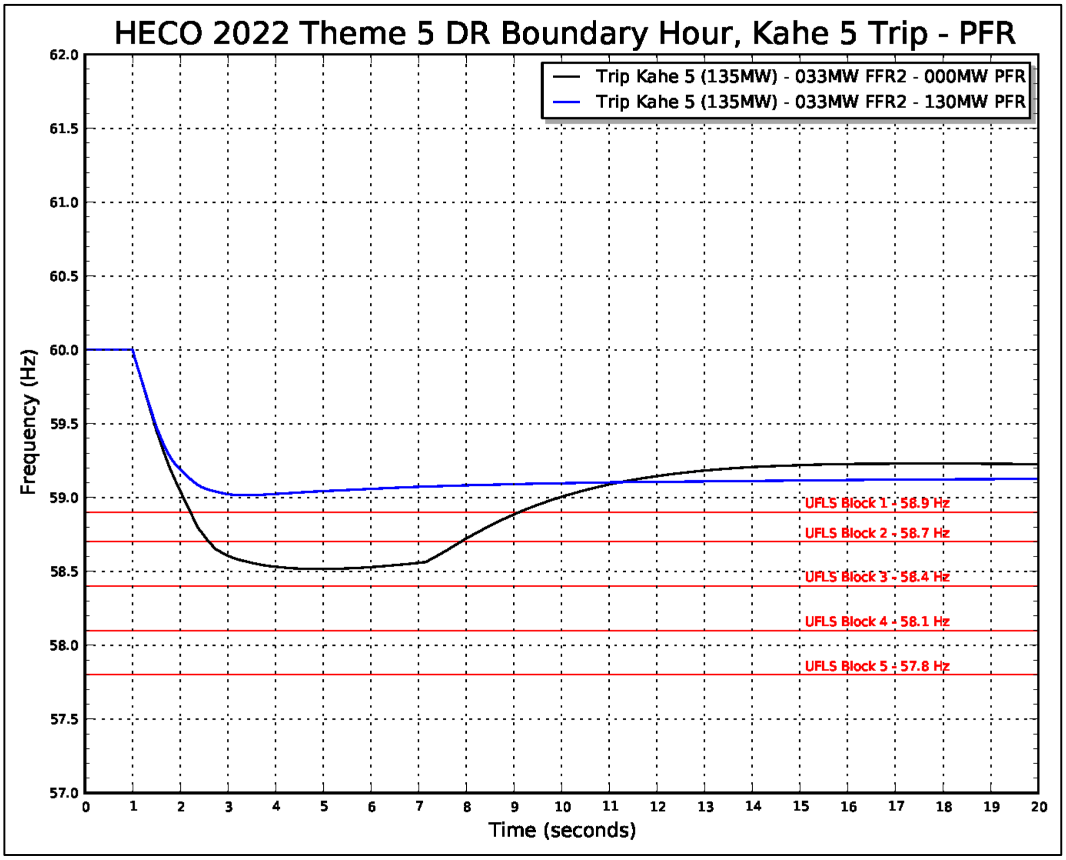

Figure O-168. Frequency Response Profile PFR Sensitivity Boundary Hour

Figure O-168 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 130 MW. This is in addition to the 33 MW of FFR2 and 130 MW of upward regulation from thermal generation.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

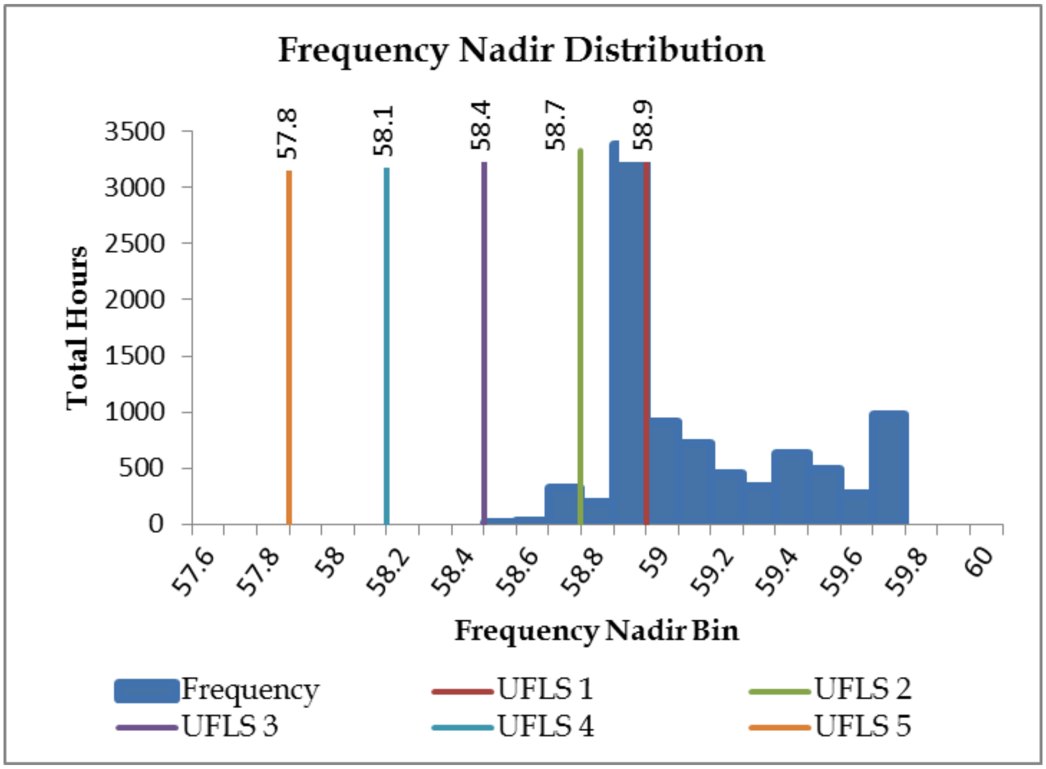

Figure O-169. Frequency Nadir Histogram 2023

Figure O-169 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 3387 hours was 8:00 PM on Friday, February 17. The frequency nadir range for the typical hour is 58.8- 58.9 Hz that requires one block of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 5 hours was 12:00 AM on Saturday, January 28. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires four blocks of UFLS to stabilize system frequency.

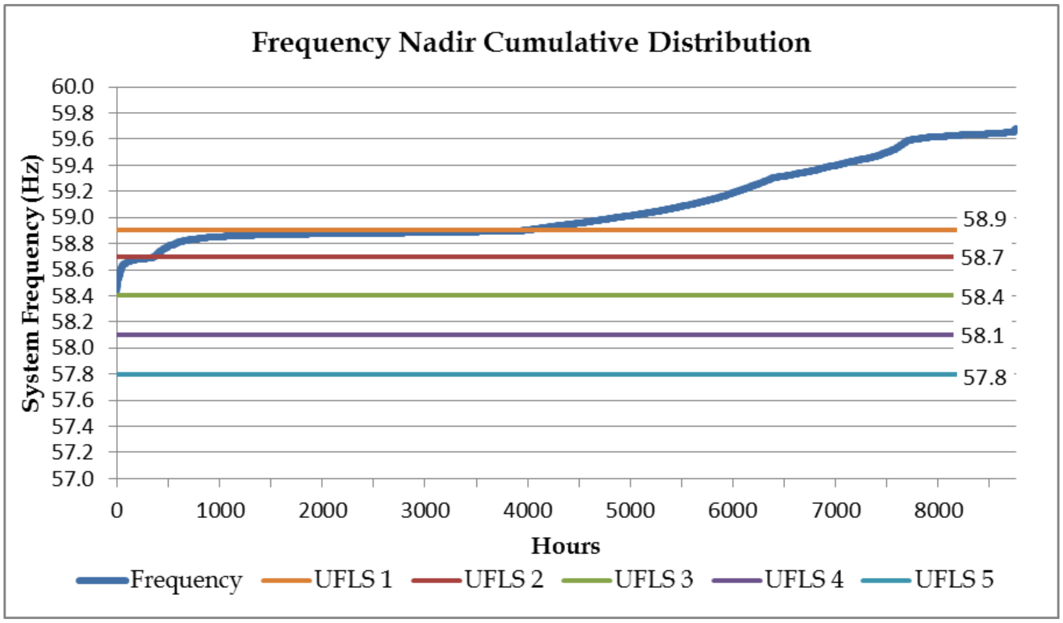

Figure O-170. Frequency Nadir Duration Curve 2023

Figure O-170 shows the frequency nadir duration curve for 2023. The system is at risk of UFLS for 3957 hours of the year.

Unit	Unit Ratings							DR - K5 Trip Typical Fri 2/17/23 Hour 20			DR - K5 Trip Boundary Sat 1/28/23 Hour 24		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.5	10.5	10.5	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426	82.2	0.0	58.4			
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426	82.2	0.0	58.4			
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	86.2	0.0	62.5			
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357	85.3	0.0	61.7	85.3	0.0	61.7
Kahe 5	134.6	21.0			4.36	158.8	692	134.6	0.0	113.6	134.6	0.0	113.6
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256	25.0	28.7	1.2			
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426				59.0	27.2	34.9
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11	4.0	4.0	2.0			
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 2	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 3	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 4	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 5	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3	16.6	0.2	9.9
JBPHH 6	16.8	6.7			0.99	21.8	22	15.0	1.8	8.3			
KMCBH 1	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 2	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 3	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 4	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 5	9.2	4.6			0.99	10.9	11	9.2	0.0	4.6	9.2	0.0	4.6
KMCBH 6	9.2	4.6			0.99	10.9	11						
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						31			38		
-Kahuku	30	0						1			2		
-Kawailoa	69	0						10			9		
-Na Pua Makani	24	0						12			12		
-CBRE Wind	10	0						2			4		
DG-PV	744	0						0			0		
Station PV	603	0						0			0		
Total Kinetic Energy									4780			3564	
Total Load									919			689	
Total Thermal Generation									889			650	
Total Renewable Generation									31			38	
Total Generation									919			689	
Excess Generation									0			0	
Total Up Regulation									67			39	
Total Down Regulation									581			433	
Total FFR2 Capacity									49			35	
Legacy DG-PV	59.3Hz Capacity			73.5				59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity			215.9				60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-70. Unit Commitment and Dispatch 2023

Table O-70 shows the unit commitment and dispatch for the typical hour (2/17/23, 8:00 PM) and boundary hour (1/28/23, 12:00 AM).

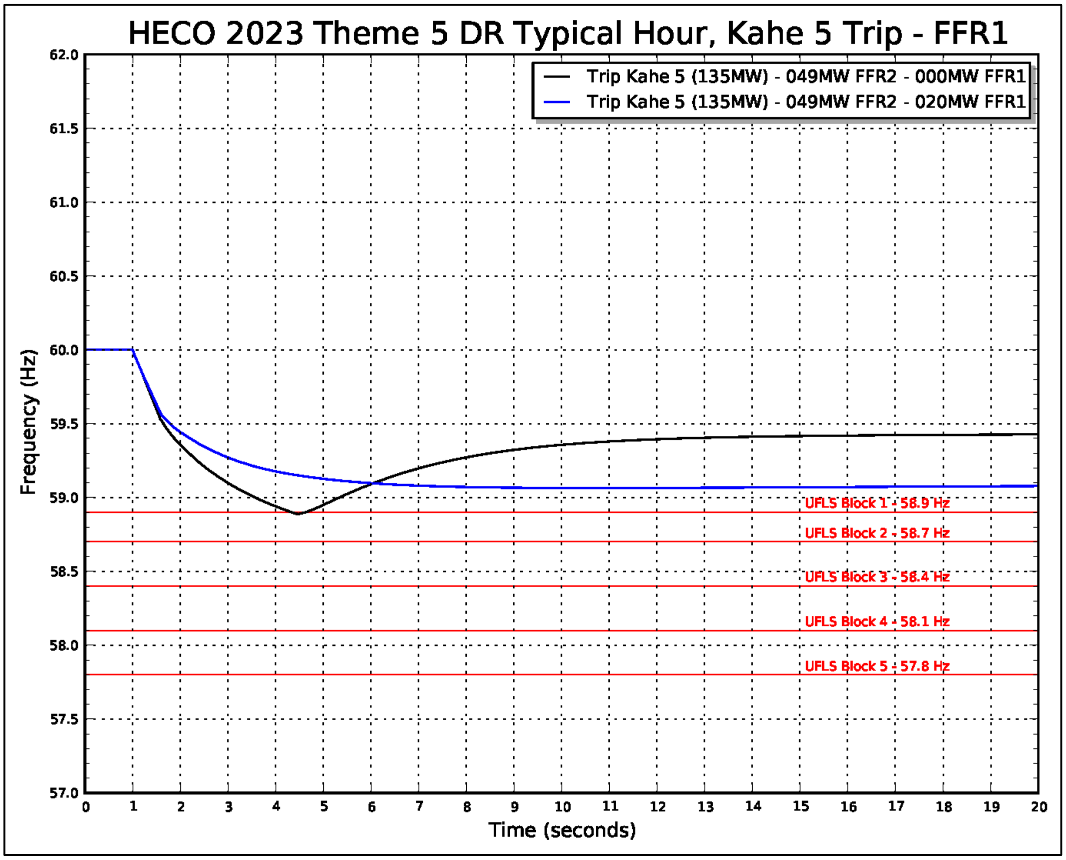

Figure O-171. Frequency Response Profile FFR1 Typical Hour

Figure O-171 shows the frequency response profile for a Kahe 5 trip at 135 MW for a typical hour. System kinetic energy is 4780 MW-sec and the capacity of FFR2 is 49 MW. With no FFR1, the frequency nadir is 58.9 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 20 MW. This is in addition to the 49 MW of FFR2.

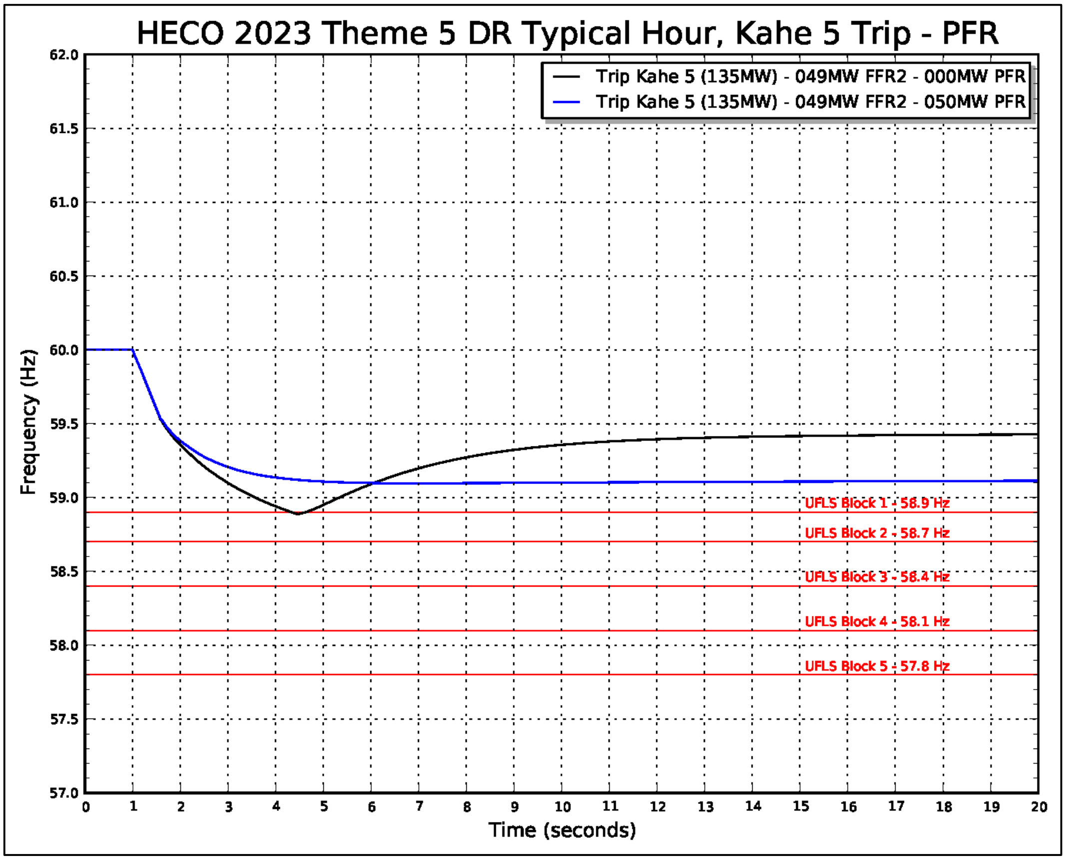

Figure O-172. Frequency Response Profile PFR Typical Hour

Figure O-172 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 50 MW. This is in addition to the 49 MW of FFR2 and 67 MW of upward regulation from thermal generation.

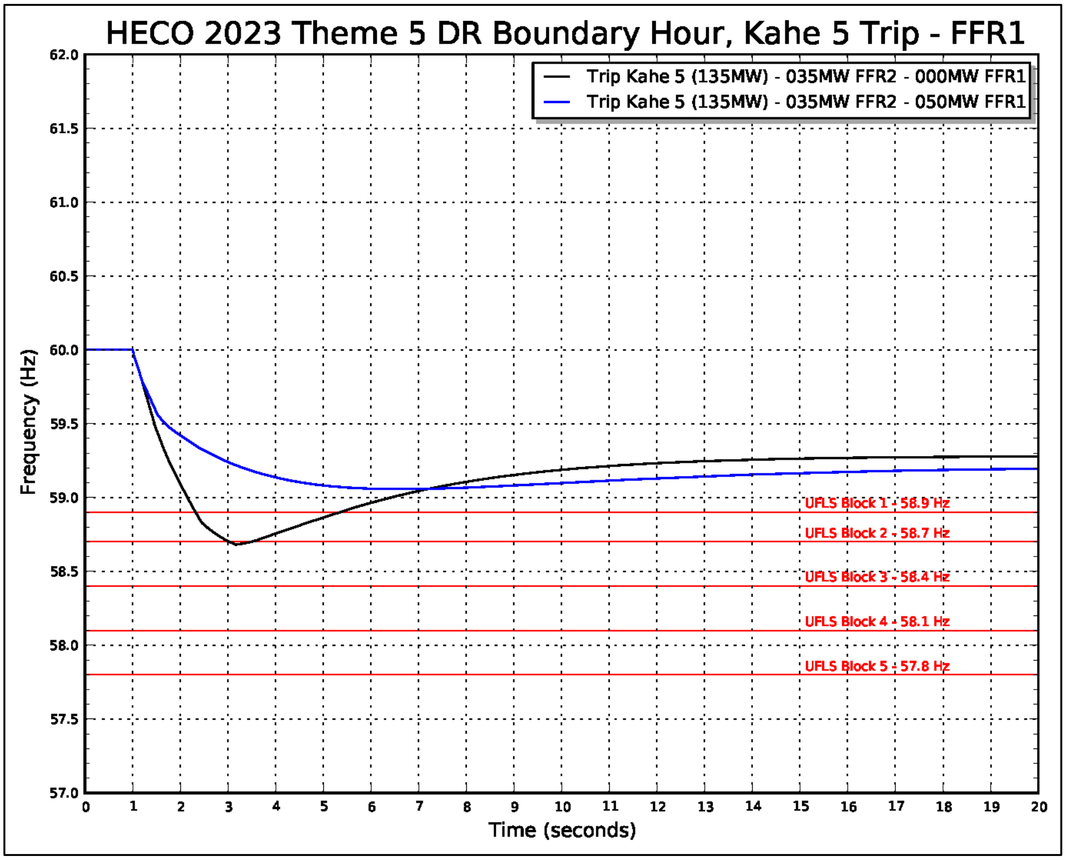

Figure O-173. Frequency Response Profile FFR1 Boundary Hour

Figure O-173 shows the frequency response profile for a Kahe 5 trip at 135 MW for a boundary hour. System kinetic energy is 3564 MW-sec and the capacity of FFR2 is 35 MW. With no FFR1, the frequency nadir is 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 50 MW. This is in addition to the 35 MW of FFR2.

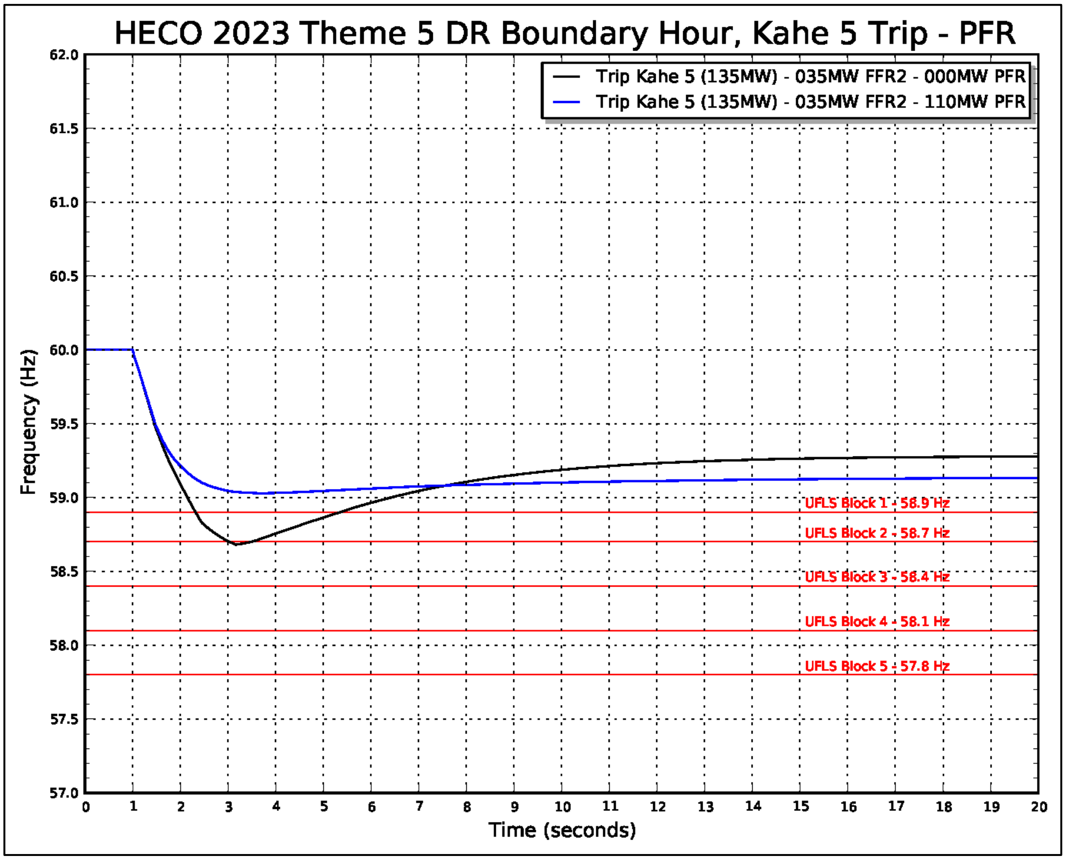

Figure O-174. Frequency Response Profile PFR Boundary Hour

Figure O-174 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 110 MW. This is in addition to the 35 MW of FFR2 and 39 MW of upward regulation from thermal generation.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

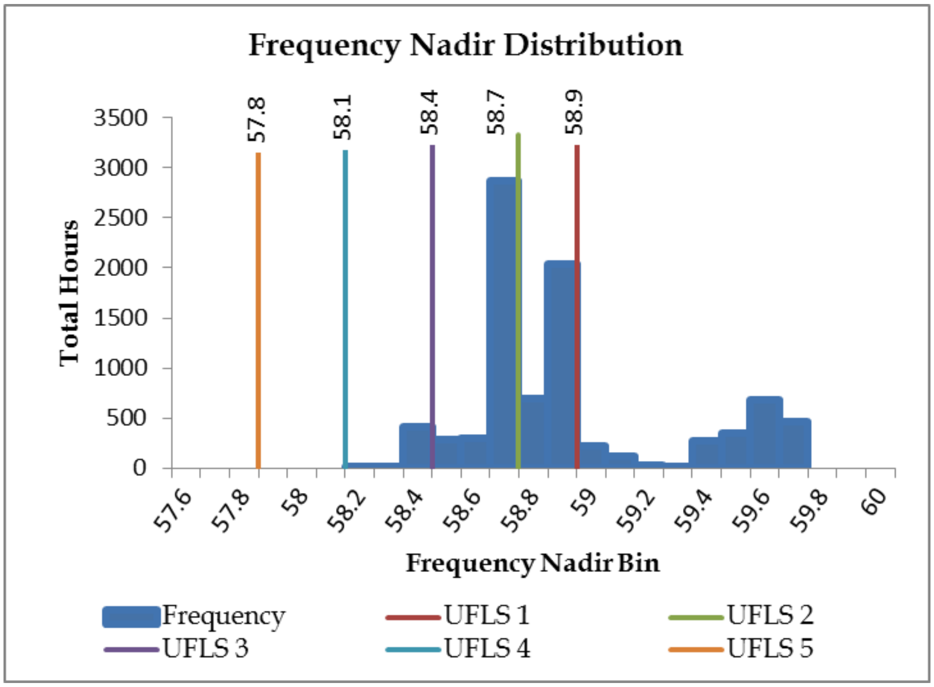

Figure O-175. Frequency Nadir Histogram 2025

Figure O-175 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 2865 hours was 8:00 AM on Wednesday, June 18. The frequency nadir range for the typical hour is 58.6- 58.7 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of one hour was 3:00 AM on Monday, March 17. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires three blocks of UFLS to stabilize system frequency.

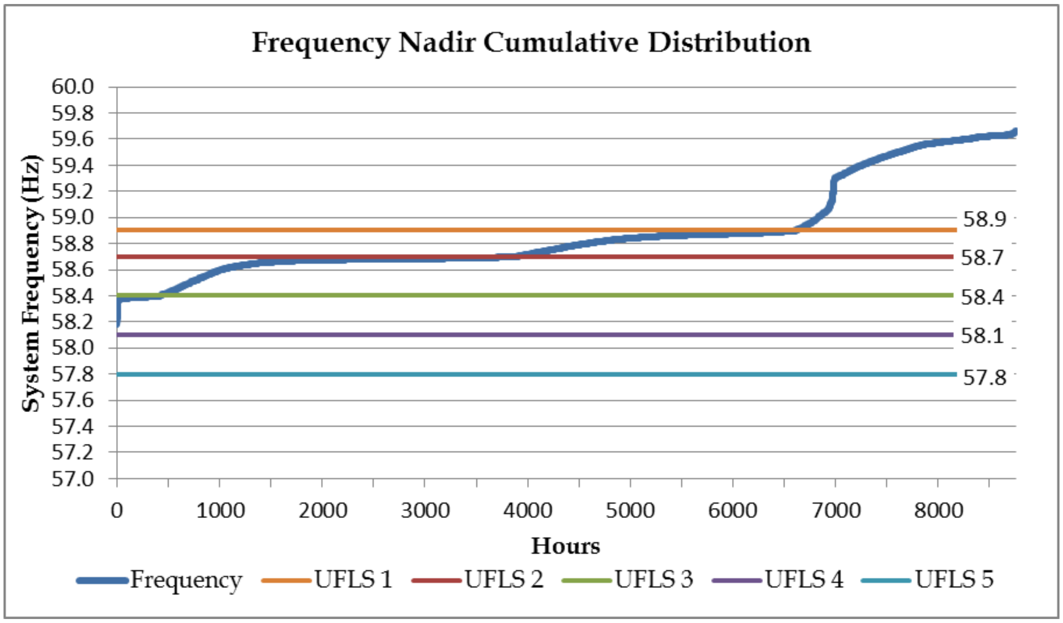

Figure O-176. Frequency Nadir Duration Curve 2023

Figure O-176 shows the frequency nadir duration curve for 2023. The system is at risk of UFLS for 3957 hours of the year.

Unit	Unit Ratings							DR - GE CT1 Trip Typical Wed 6/18/25 Hour 8			DR - GE CT1 Trip Boundary Mon 3/17/25 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	46.0	0.0	21.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	22.5	0.0	12.5			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	40.0	0.0	30.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357	36.2	50.0	12.5	35.8	50.4	12.1
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426	32.3	53.9	8.2			
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22	13.9	2.9	7.2	14.5	2.2	7.9
JBPHH 2	16.8	6.7			0.99	21.8	22	13.9	2.9	7.2	14.5	2.2	7.9
JBPHH 3	16.8	6.7			0.99	21.8	22	13.9	2.9	7.2	14.5	2.2	7.9
JBPHH 4	16.8	6.7			0.99	21.8	22				14.5	2.2	7.9
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 2	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 3	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 4	9.2	4.6			0.99	10.9	11	8.9	0.3	4.3			
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	67.0	0.0	38.0
GE-151CT2	84.0	42.0			3.40	98.5	335						
GE-151ST2	67.0	29.0			4.70	99.3	467						
GE-151CT3	84.0	42.0			3.40	98.5	335						
GE-151ST3	67.0	29.0			4.70	99.3	467						
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	0.0			0.0		
Kahe 6	133.8	40.0			1.75	158.8	278						
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						50			70		
-Kahuku	30	0						6			23		
-Kawailoa	69	0						19			20		
-Na Pua Makani	24	0						17			18		
-CBRE Wind	10	0						2			2		
DG-PV	777	0						108			0		
Station PV	683	0						132			0		
Total Kinetic Energy								4058			3467		
Total Load								864			558		
Total Thermal Generation								573			488		
Total Renewable Generation								290			70		
Total Generation								864			558		
Excess Generation								0			0		
Total Up Regulation								114			70		
Total Down Regulation								313			274		
Total FFR2 Capacity								41			32		
Legacy DG-PV	59.3Hz Capacity	73.5						59.3Hz Output	10.1		59.3Hz Output	0.0	
	60.5Hz Capacity	215.9						60.5Hz Output	29.8		60.5Hz Output	0.0	

Table O-71. Unit Commitment and Dispatch 2025

Table O-71 shows the unit commitment and dispatch for the typical hour (6/18/25, 8:00 AM) and boundary hour (3/17/25, 3:00 AM).

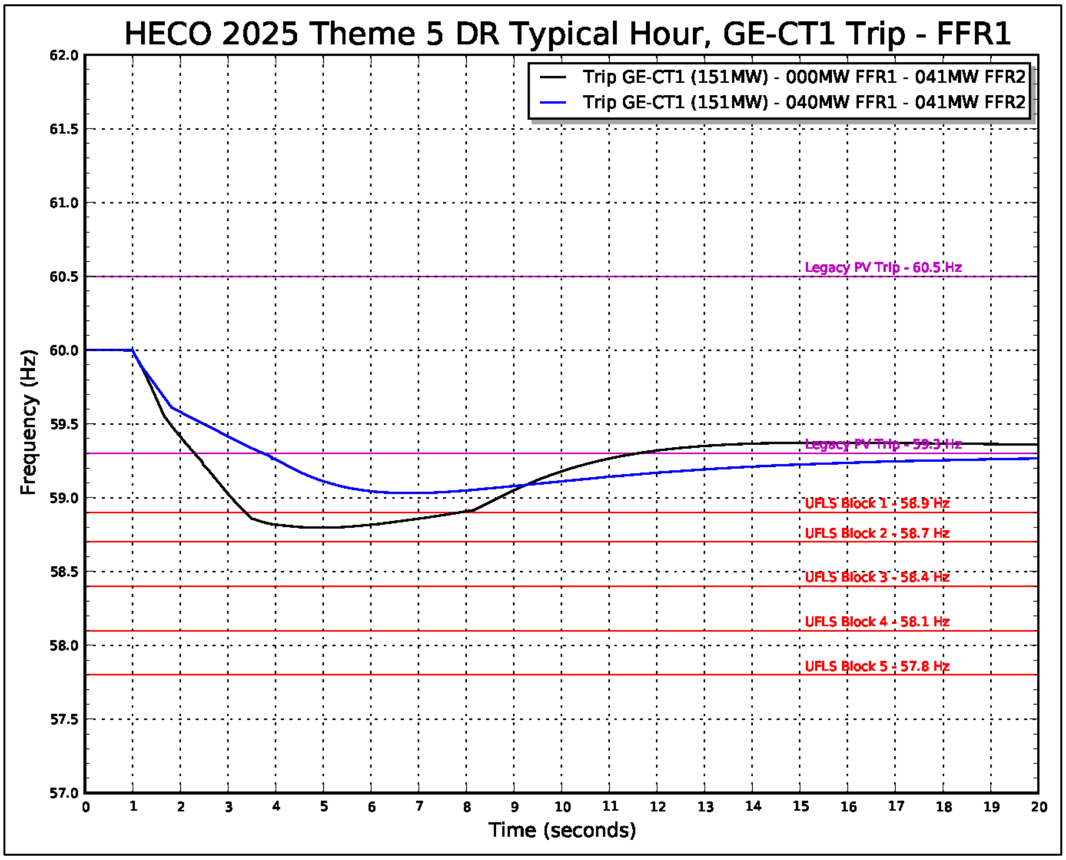

Figure O-177. Frequency Response Profile FFR1 Typical Hour

Figure O-177 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a typical hour. System kinetic energy is 4058 MW-sec, the capacity of FFR2 is 41 MW, and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 10.1 MW. With no FFR1, the frequency nadir is 58.8 Hz and one block of UFLS is required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 40 MW. This is in addition to the 41 MW of FFR2.

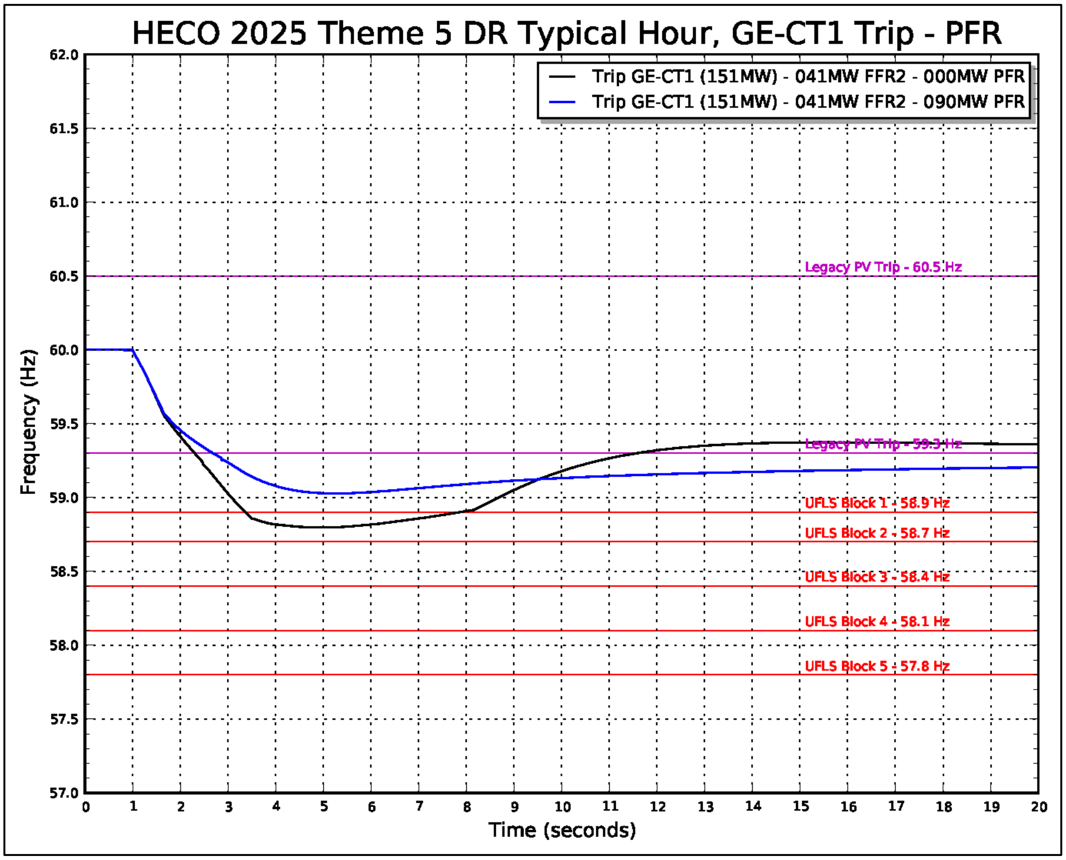

Figure O-178. Frequency Response Profile PFR Typical Hour

Figure O-178 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 41 MW of FFR2 and 114 MW of upward regulation from thermal generation.

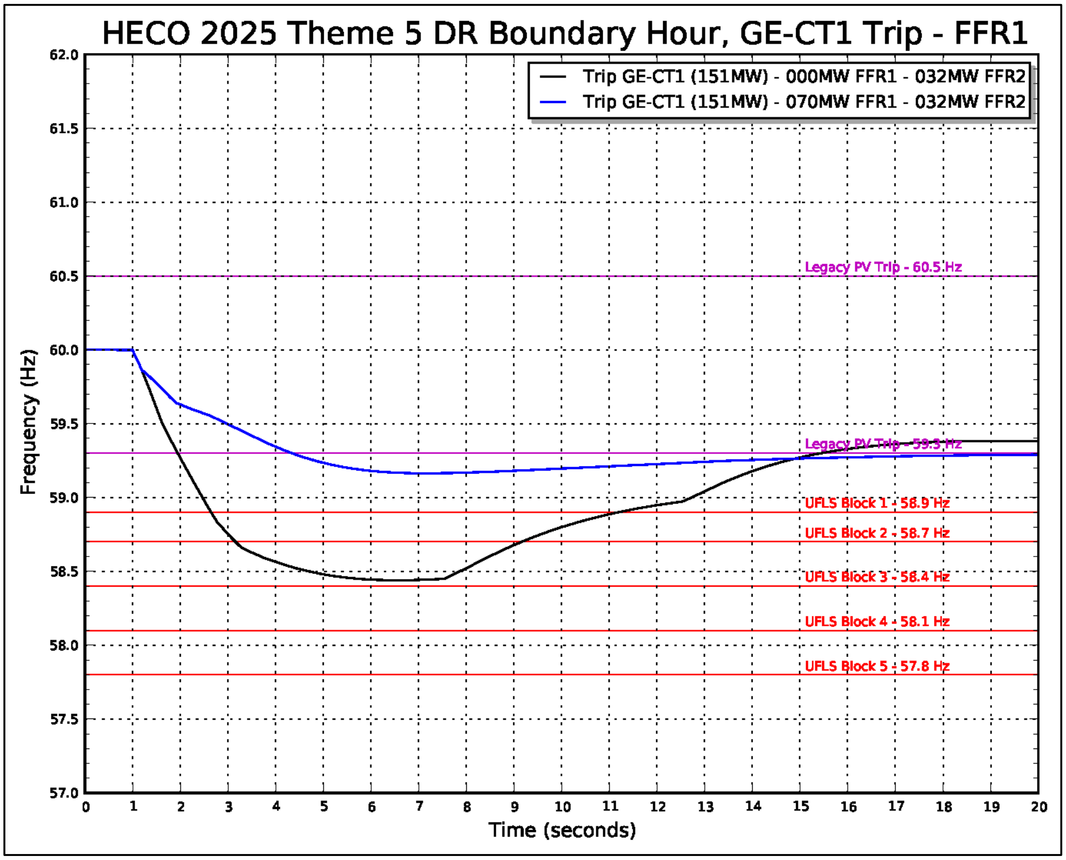

Figure O-179. Frequency Response Profile FFR1 Boundary Hour

Figure O-179 shows the frequency response profile for a GE CT1 trip in combined–cycle operation for a boundary hour. System kinetic energy is 3467 MW-sec and the capacity of FFR2 is 32 MW. With no FFR1, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 32 MW of FFR2.

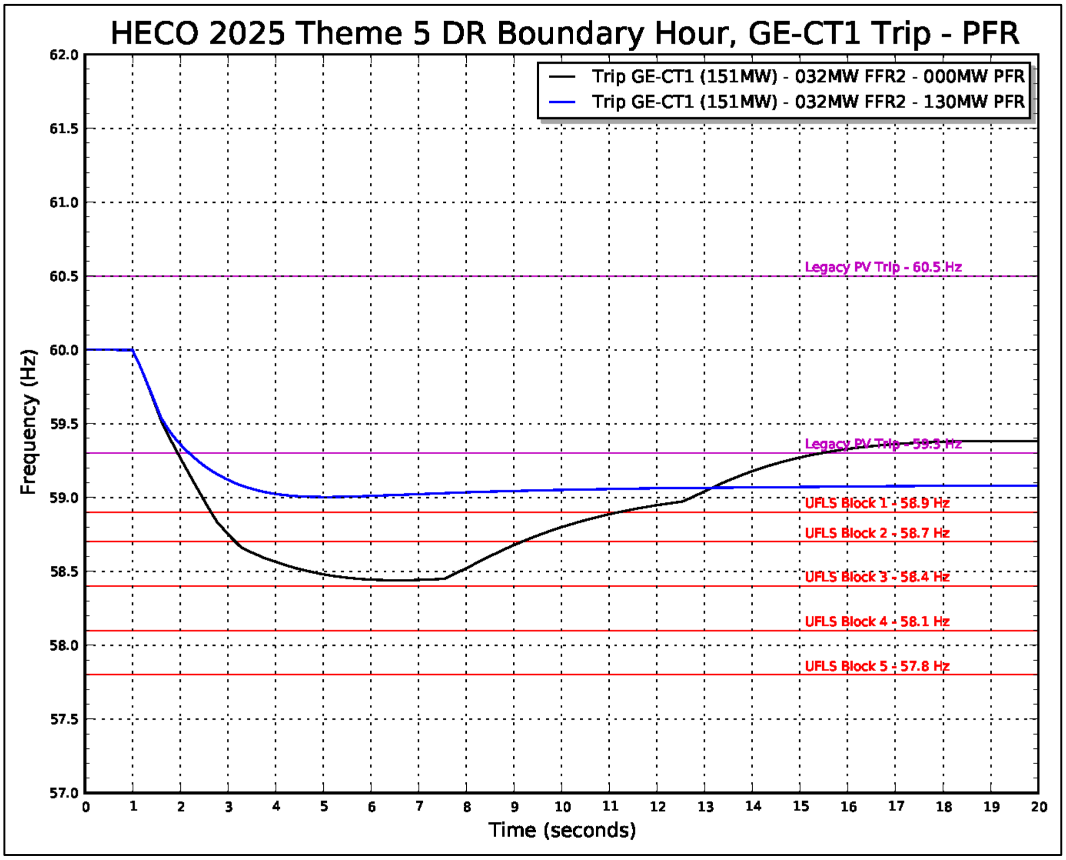

Figure O-180. Frequency Response Profile PFR Boundary Hour

Figure O-180 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 130 MW. This is in addition to the 32 MW of FFR2 and 70 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

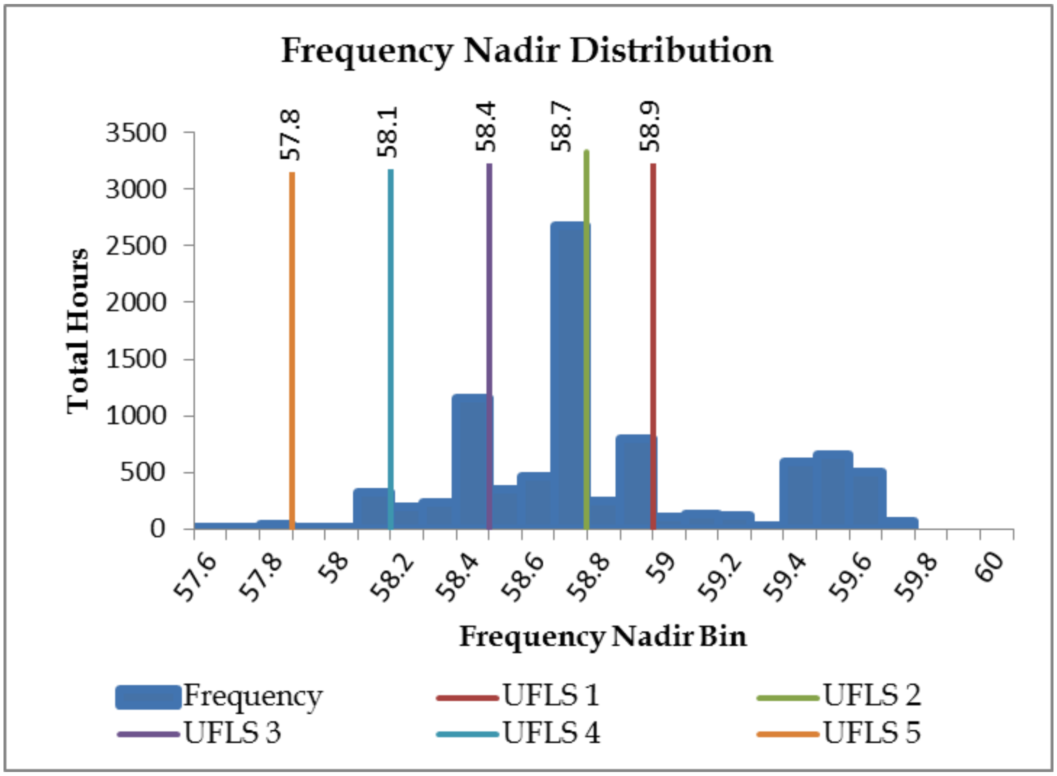

Figure O-181. Frequency Nadir Histogram 2030

Figure O-181 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 1155 hours was 1:00 AM on Monday, September 23. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 39 hours was 3:00 AM on Wednesday, April 17. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

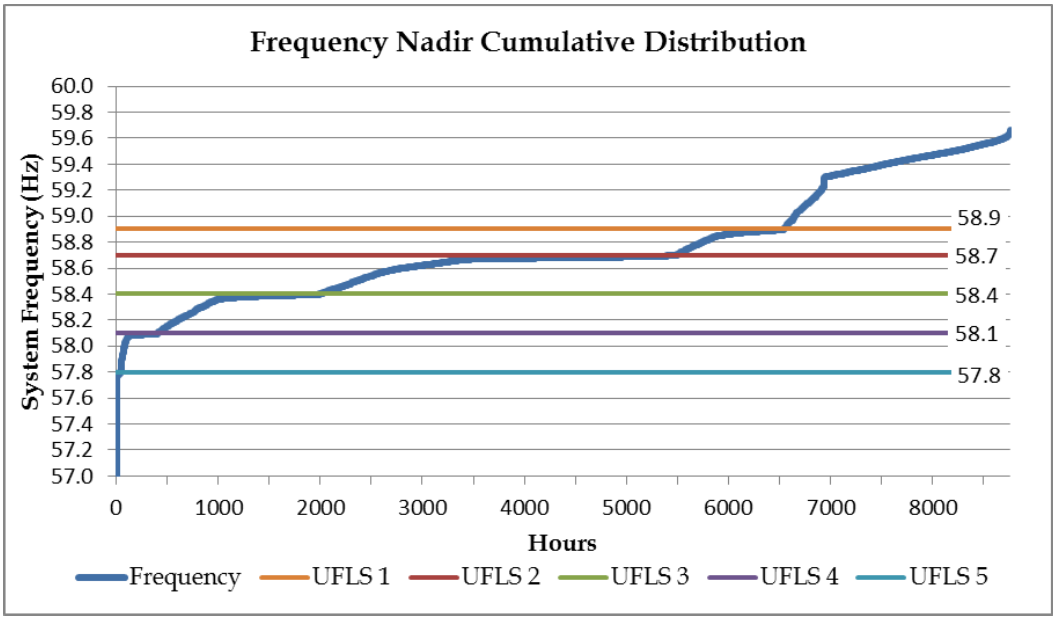

Figure O-182. Frequency Nadir Duration Curve 2030

Figure O-182 shows the frequency nadir duration curve for 2030. The system is at risk of UFLS for 6543 hours of the year.

Unit	Unit Ratings							DR - GE CT2 Trip Typical Mon 9/23/30 Hour 1			DR - GE CT1 Trip Boundary Wed 4/17/30 Hour 3		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	35.0	11.0	10.0	42.0	4.0	17.0
HPOWER-2	22.5	10.0			3.41	42.1	144						
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0	84.0	0.0	55.0
Kalaeloa ST	40.0	10.0			4.70	61.1	287	40.0	0.0	30.0	20.0	20.0	10.0
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591	84.0	0.0	55.0			
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11	4.0	4.0	2.0			
JBPHH 1	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8	16.7	0.1	10.0
JBPHH 2	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8	16.7	0.1	10.0
JBPHH 3	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8			
JBPHH 4	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8			
JBPHH 5	16.8	6.7			0.99	21.8	22	13.4	3.3	6.8			
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 2	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 3	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 4	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 5	9.2	4.6			0.99	10.9	11	8.5	0.6	4.0			
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335				84.0	0.0	42.0
GE-151ST1	67.0	29.0			4.70	99.3	467				66.1	0.9	37.1
GE-151CT2	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0	82.6	1.4	40.6
GE-151ST2	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0	63.3	3.7	34.3
GE-151CT3	84.0	42.0			3.40	98.5	335	84.0	0.0	42.0			
GE-151ST3	67.0	29.0			4.70	99.3	467	67.0	0.0	38.0			
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	2.3			0.0		
Kahe 6	133.8	40.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	163	0						31			72		
-Kahuku	30	0						6			24		
-Kawailoa	69	0						11			27		
-Na Pua Makani	24	0						6			21		
-CBRE Wind	10	0						2			0		
DG-PV	871	0						0			0		
Station PV	843	0						0			0		
Total Kinetic Energy									4276			3555	
Total Load									687			466	
Total Load Shifting									-5			-82	
Total Thermal Generation									661			475	
Total Renewable Generation									31			72	
Total Generation									692			548	
Excess Generation									0			0	
Total Up Regulation									35			30	
Total Down Regulation									366			256	
Total FFR2 Capacity									33			33	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity		215.9					60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-72. Unit Commitment and Dispatch 2030

Table O-72 shows the unit commitment and dispatch for the typical hour (9/23/30, 1:00 AM) and boundary hour (4/17/30, 3:00 AM).

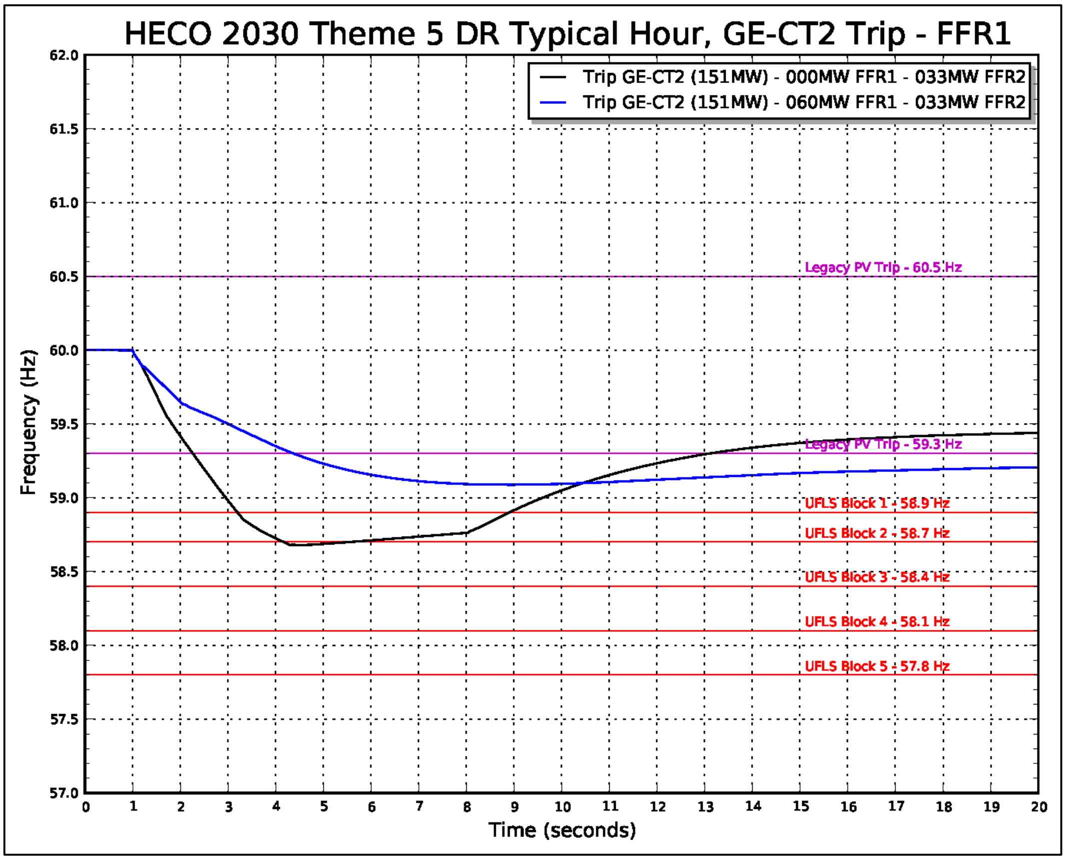

Figure O-183. Frequency Response Profile FFR1 Typical Hour

Figure O-183 shows the frequency response profile for a GE CT2 trip in combined-cycle operation for a typical hour. System kinetic energy is 4276 MW-sec and the capacity of FFR2 is 33 MW. With no FFR1, the frequency nadir breaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 60 MW. This is in addition to the 33 MW of FFR2.

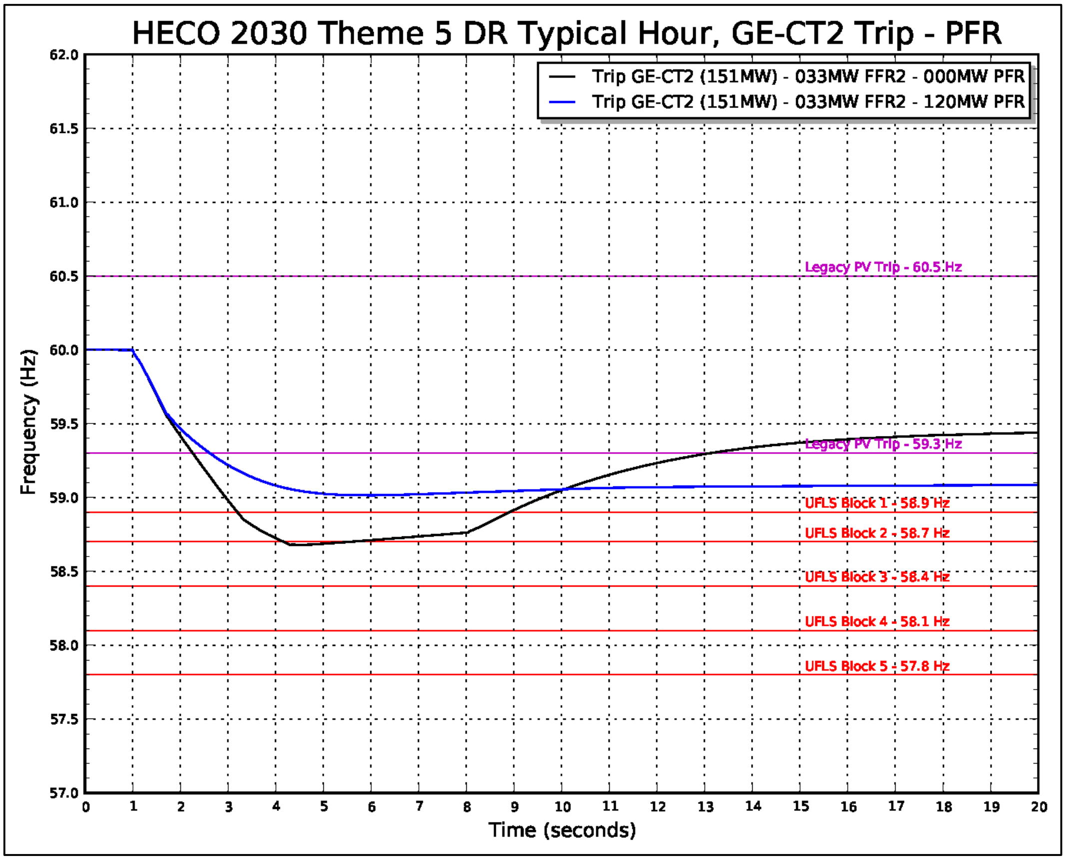

Figure O-184. Frequency Response Profile PFR Typical Hour

Figure O-184 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 120 MW. This is in addition to the 33 MW of FFR2 and 35 MW of upward regulation from thermal generation.

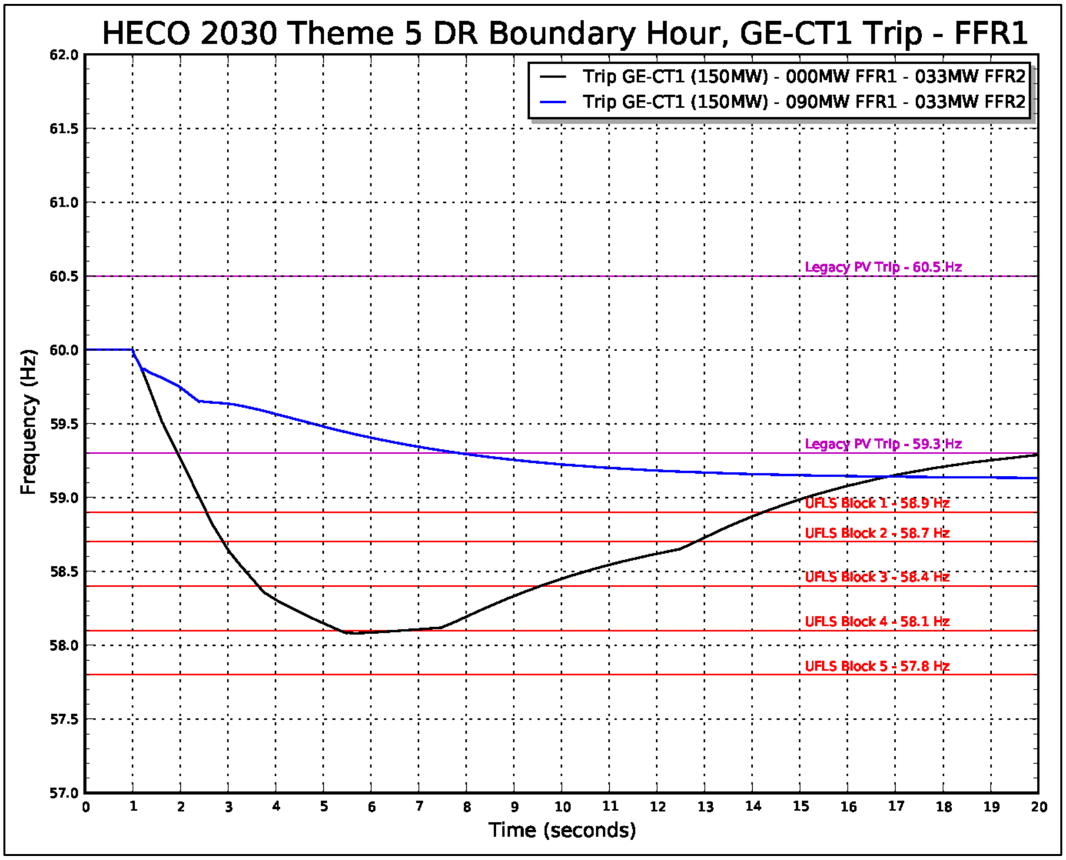

Figure O-185. Frequency Response Profile FFR1 Boundary Hour

Figure O-185 shows the frequency response profile for a GE CT1 trip in combined-cycle operation for a boundary hour. System kinetic energy is 3555 MW-sec and the capacity of FFR2 is 33 MW. With no FFR1, the frequency nadir breaches 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 33 MW of FFR2.

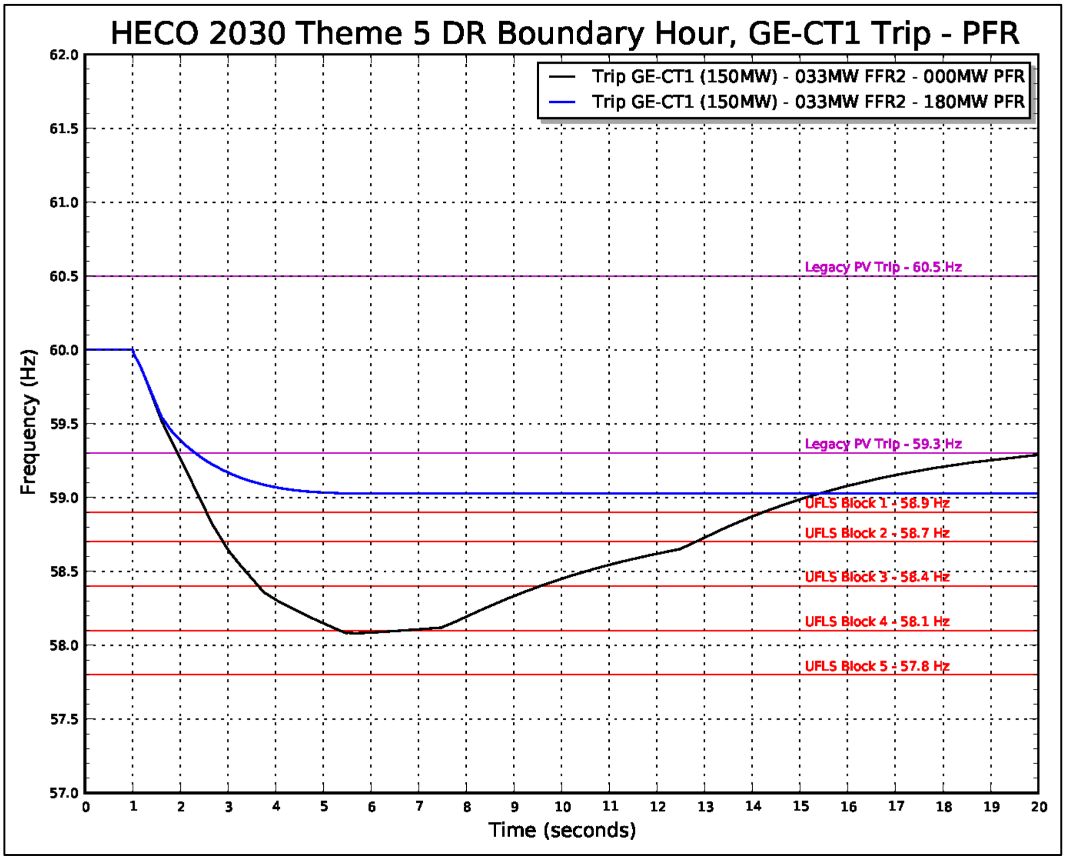

Figure O-186. Frequency Response Profile PFR Boundary Hour

Figure O-186 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 180 MW. This is in addition to the 33 MW of FFR2 and 30 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

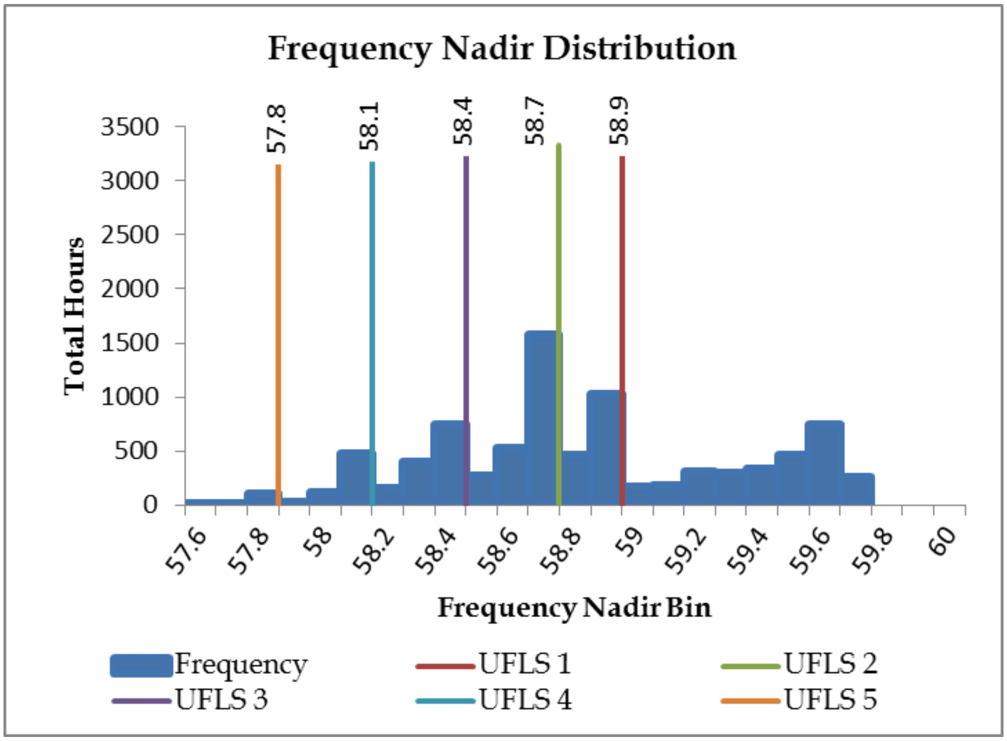

Figure O-187. Frequency Nadir Histogram 2045

Figure O-187 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour was selected from the hourly distribution of 753 hours was 10:00 AM on Monday, January 23. The frequency nadir range for the typical hour is 58.3- 58.4 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from the hourly distribution of 22 hours was 5:00 AM on Sunday, October 22. The frequency nadir range for the boundary hour is 57.7 – 57.8 Hz that requires five blocks of UFLS to stabilize system frequency.

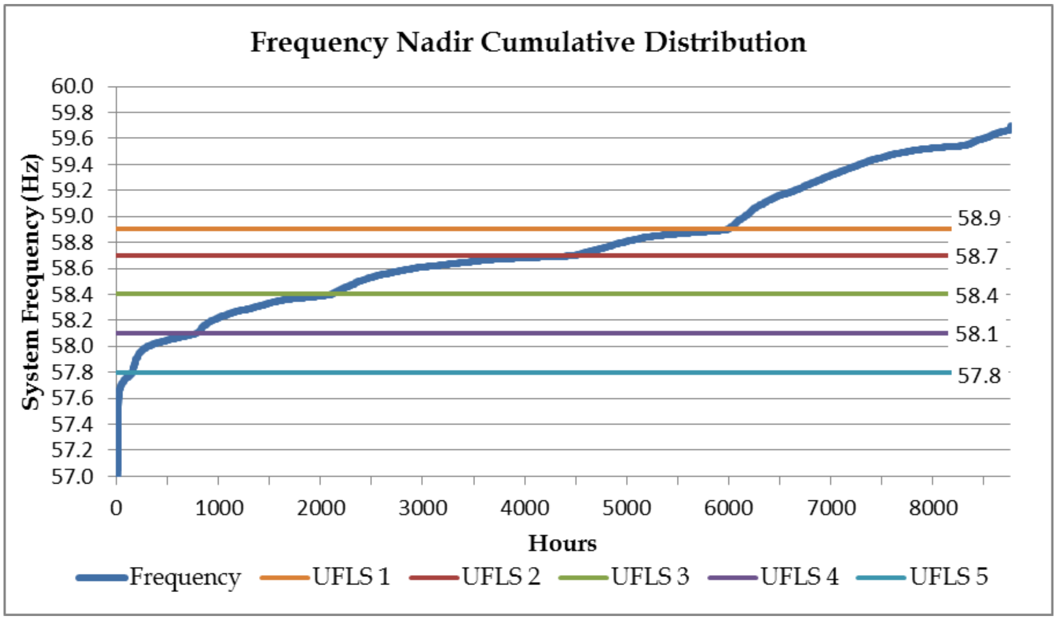

Figure O-188. Frequency Nadir Duration Curve 2045

Figure O-188 shows the frequency nadir duration curve for 2045. The system is at risk of UFLS for 5989 hours of the year.

Unit	Unit Ratings							DR - Off Shore Wind Trip Typical Mon 1/23/45 Hour 10			DR - Off Shore Wind Trip Boundary Sun 10/22/45 Hour 5		
	Pmax	Pmin			Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
HPOWER-1	46.0	25.0			2.78	75.0	209	25.0	21.0	0.0	35.0	11.0	10.0
HPOWER-2	22.5	10.0			3.41	42.1	144	10.0	12.5	0.0			
AES	189.0	63.0			2.57	239.0	615						
Kalaeloa CT-1	84.0	29.0			4.96	119.2	591						
Kalaeloa ST	40.0	10.0			4.70	61.1	287						
Kalaeloa CT-2	84.0	29.0			4.96	119.2	591						
Kahe 1	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 2	82.2	23.8	25.0	5.0	4.44	96.0	426						
Kahe 3	86.2	23.7	25.0	5.0	3.54	101.0	357						
Kahe 4	85.3	23.6	25.0	5.0	3.54	101.0	357						
Kahe 5	134.6	21.0			4.36	158.8	692						
Kahe 6	133.8	40.0			4.36	158.8	692						
Waiau 3	47.0	23.7			4.51	57.5	259						
Waiau 4	46.5	23.5			4.51	57.5	259						
Waiau 5	54.5	23.5			4.07	64.0	261						
Waiau 6	53.7	23.8			4.00	64.0	256						
Waiau 7	83.3	23.8	25.0	5.0	4.44	96.0	426						
Waiau 8	86.2	24.1	25.0	5.0	4.44	96.0	426						
Waiau 9	52.9	5.9			7.84	57.0	447						
Waiau 10	49.9	5.9			7.84	57.0	447						
CIP1	112.2	41.2			4.72	162.0	765						
Schofield 1	8.0	2.0			0.99	10.9	11						
Schofield 2	8.0	2.0			0.99	10.9	11						
Schofield 3	8.0	2.0			0.99	10.9	11						
Schofield 4	8.0	2.0			0.99	10.9	11						
Schofield 5	8.0	2.0			0.99	10.9	11						
Schofield 6	8.0	2.0			0.99	10.9	11						
JBPHH 1	16.8	6.7			0.99	21.8	22						
JBPHH 2	16.8	6.7			0.99	21.8	22						
JBPHH 3	16.8	6.7			0.99	21.8	22						
JBPHH 4	16.8	6.7			0.99	21.8	22						
JBPHH 5	16.8	6.7			0.99	21.8	22						
JBPHH 6	16.8	6.7			0.99	21.8	22						
KMCBH 1	9.2	4.6			0.99	10.9	11						
KMCBH 2	9.2	4.6			0.99	10.9	11						
KMCBH 3	9.2	4.6			0.99	10.9	11						
KMCBH 4	9.2	4.6			0.99	10.9	11						
KMCBH 5	9.2	4.6			0.99	10.9	11						
KMCBH 6	9.2	4.6			0.99	10.9	11						
GE-151CT1	84.0	42.0			3.40	98.5	335						
GE-151ST1	67.0	29.0			4.70	99.3	467						
GE-151CT2	84.0	42.0			3.40	98.5	335						
GE-151ST2	67.0	29.0			4.70	99.3	467						
GE-151CT3	84.0	42.0			3.40	98.5	335						
GE-151ST3	67.0	29.0			4.70	99.3	467						
GE-151CT4	84.0	42.0			3.40	98.5	335						
GE-151ST4	67.0	29.0			4.70	99.3	467						
GE-151CT5	84.0	42.0			3.40	98.5	335						
GE-151ST5	67.0	29.0			4.70	99.3	467						
PSH	10.0	-10.0			2.43	11.8	29	-10.0			-10.0		
Kahe 6	133.8	40.0			1.75	158.8	278	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 3	47.0	23.7			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Waiau 4	46.5	23.5			2.32	57.5	133	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 8	0.0	0.0			1.99	62.5	124	0.0	Synch. Cond.		0.0	Synch. Cond.	
Honolulu 9	0.0	0.0			1.95	64.0	125	0.0	Synch. Cond.		0.0	Synch. Cond.	
Total Wind	963	0						654			599		
-Kahuku	30	0						5			4		
-Kawailoa	69	0						10			4		
-Na Pua Makani	24	0						0			8		
-CBRE Wind	10	0						2			1		
-Future Wind	30	0						0			0		
-Off Shore Wind	800	0						638			582		
DG-PV	1225	0						432			0		
Station PV	1043	0						120			0		
Total Kinetic Energy									1146			1002	
Total Load									1230			470	
Total Load Shifting									0			-154	
Total Thermal Generation									25			25	
Total Renewable Generation									1205			599	
Total Generation									1230			624	
Excess Generation									0			0	
Total Up Regulation									34			11	
Total Down Regulation									0			10	
Total FFR2 Capacity									48			40	
Legacy DG-PV	59.3Hz Capacity		73.5					59.3Hz Output		0.0	59.3Hz Output		0.0
	60.5Hz Capacity		215.9					60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-73. Unit Commitment and Dispatch 2045

Table O-73 shows the unit commitment and dispatch for the typical hour (1/23/45, 10:00 AM) and boundary hour (10/22/45, 5:00 AM).

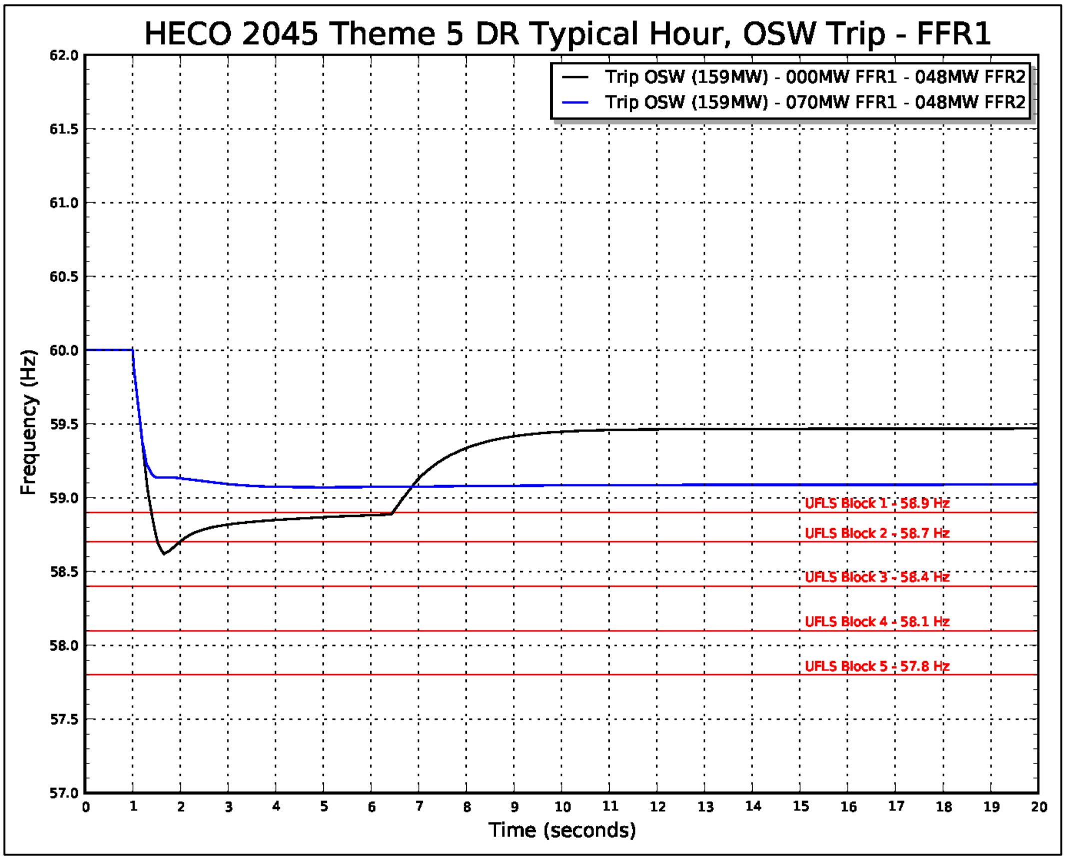

Figure O-189. Frequency Response Profile FFR1 Typical Hour

Figure O-189 shows the frequency response profile for an off-shore wind trip at 159 MW for a typical hour. System kinetic energy is 1146 MW-sec and the capacity of FFR2 is 48 MW. With no FFR1, the frequency nadir breaches 58.7 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW. This is in addition to the 48 MW of FFR2.

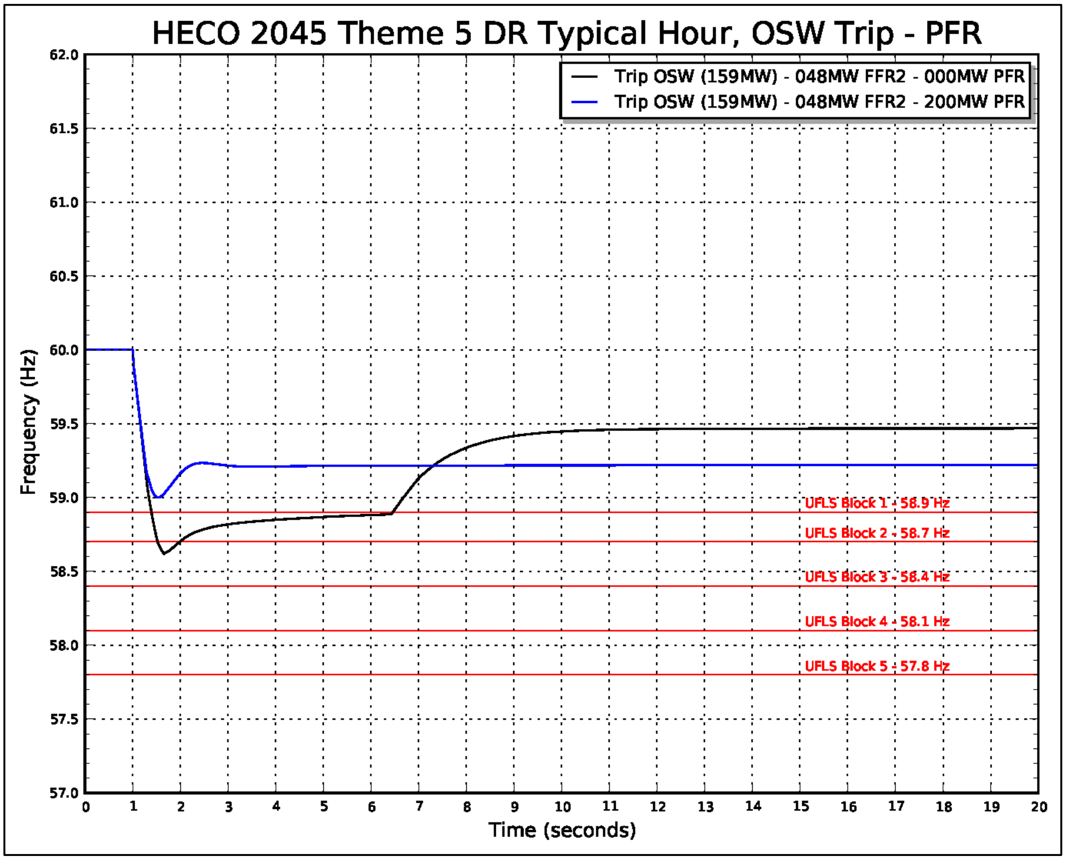

Figure O-190. Frequency Response Profile PFR Typical Hour

Figure O-190 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 200 MW. This is in addition to the 48 MW of FFR2 and 34 MW of upward regulation from thermal generation.

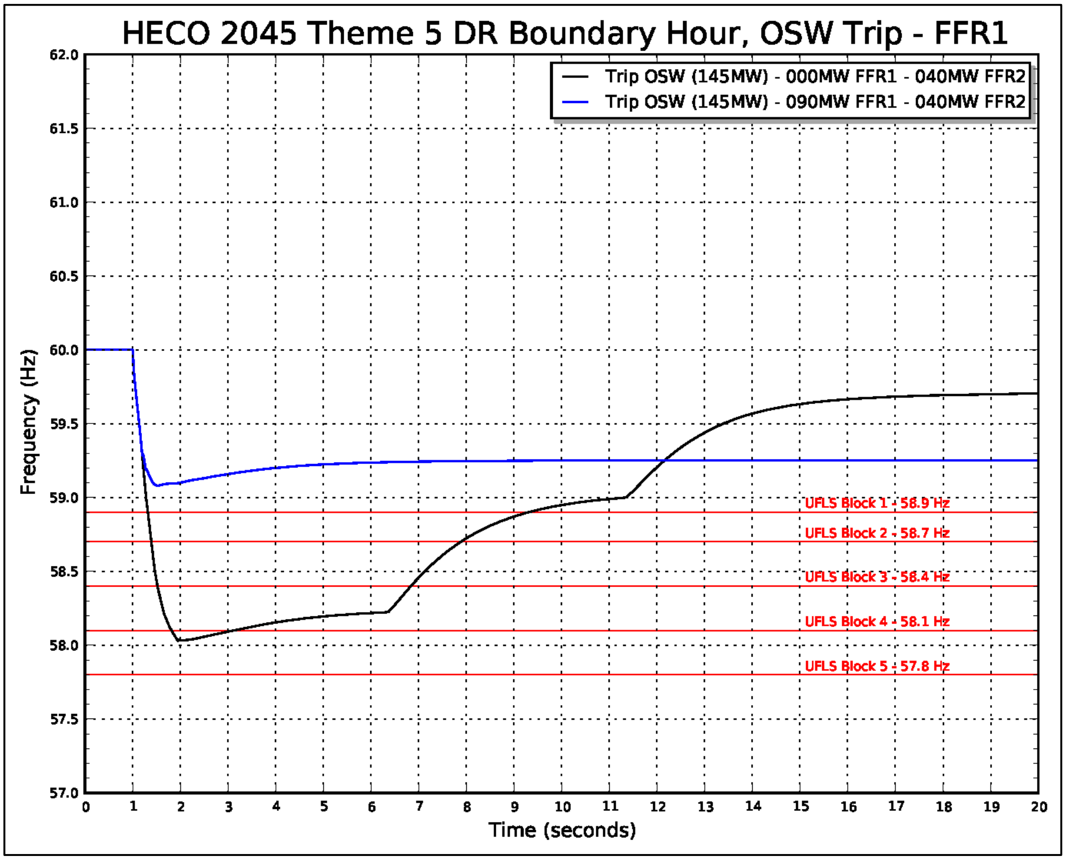

Figure O-191. Frequency Response Profile FFR1 Boundary Hour

Figure O-191 shows the frequency response profile for the FFR1 analysis. System kinetic energy is 1002 MW-sec and the capacity of FFR2 is 40 MW. With no additional FFR, the frequency nadir breaches 58.1 Hz and four blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 90 MW. This is in addition to the 40 MW of FFR2.

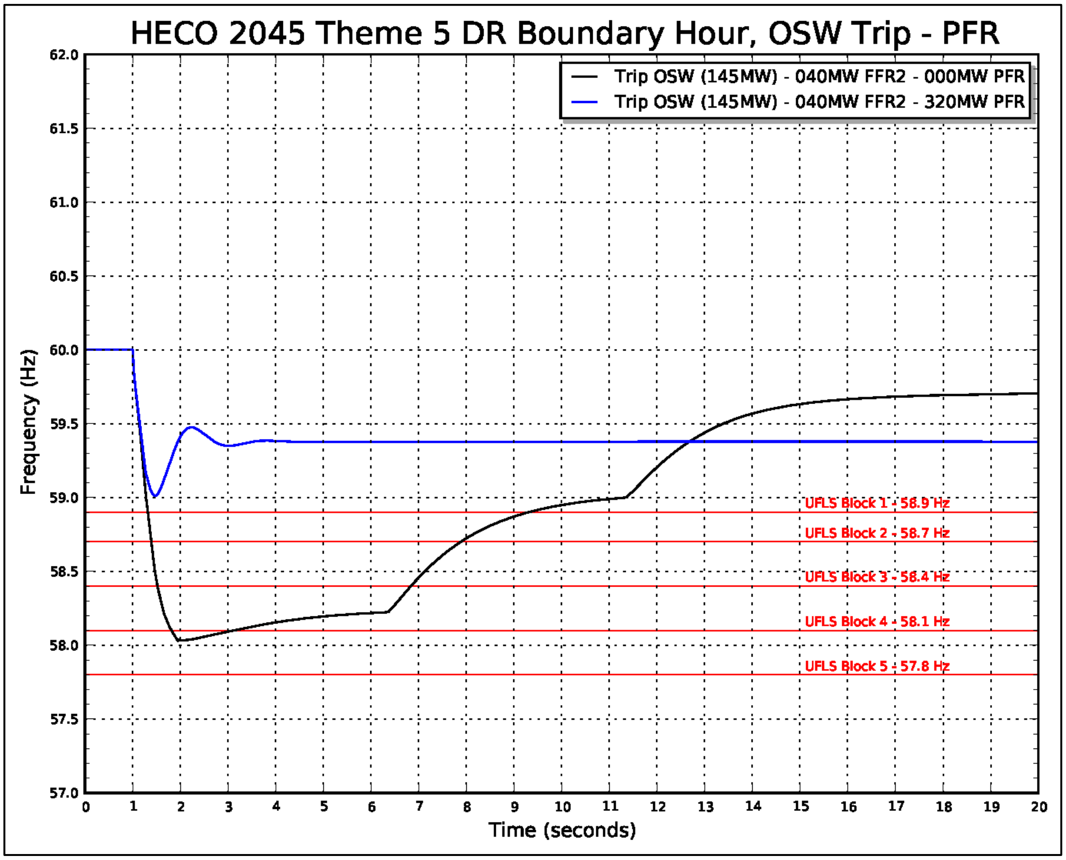

Figure O-192. Frequency Response Profile PFR Boundary Hour

Figure O-192 shows the frequency response profile for the PFR analysis. The capacity of PFR required to bring the system into compliance with TPL-001 is 320 MW. This is in addition to the 40 MW of FFR2 and 11 MW of upward regulation from thermal generation.

E3 Resource Plan Assessment

The full scope of the system security analysis was not completed for the E3 resource plans. Analysis and assessment focused on two plans; 1) No LNG; High DG-PV plan and 2) No LNG, High DG-PV; Power Supply Retirement plan.

E3 - No LNG; High DG-PV

- QV Analysis (2019 – 2021): Conversion of Honolulu 8 and 9 to synchronous condensers is required in 2020.
- Loss of Generation Analysis (2019 – 2020): FFR and PFR capacities required to bring the system into compliance with TPL-001 are similar to the Post April DR plan.
- 138 kV Fault Analysis (2019 – 2020): All normally cleared faults were stable with multiple blocks of UFLS. System performance is similar to the Post April DR plan.

E3 - No LNG; High DG-PV; Power Supply Retirements

- QV Analysis (2019 – 2021): Conversion of Honolulu 8 and 9 to synchronous condensers is not required in the 5-year action plan period.
- Loss of Generation Analysis (2019 – 2020): FFR and PFR capacities required to bring the system into compliance with TPL-001 are similar to the Post April DR plan.
- 138 kV Fault Analysis (2019 – 2020): All normally cleared faults were stable with multiple blocks of UFLS. System performance is similar to the Post April DR plan.

O'ahu Summary

The system security analysis determines technology-neutral requirements for each resource plan to ensure compliance with TPL-001. Analysis focused on 2019 through 2021 to ensure the resource plans meet system security requirements through the 5-year action plan period. System security analyses include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation contingency analysis was performed for select years beyond 2021.

The O'ahu system does not meet the requirements of TPL-001. Based on historical data, an AES trip at full output requires multiple blocks of UFLS to help stabilize system frequency. Analysis was performed for 2019 to determine capacities of frequency response reserves to mitigate an AES trip at full capacity and a Kahe Unit 5 trip at full capacity.

The O'ahu system may also be susceptible to system collapse for a normally cleared three-phase fault because of the proliferation of DG-PV. An electrical fault is the most severe disturbance on the transmission system typically characterized by high system frequency and low voltages. During a fault, system voltage can be suppressed below the 0.5 PU voltage ride-through threshold of inverter-based generation, momentarily tripping the entire capacity of DG-PV from the system. If system voltage does not recover within the 0.5-second ride-through time, inverters will disconnect from the system.

If the capacity of DG-PV is high, the momentary loss of power could drive system frequency below 57.0 Hz and initiate under-frequency protection for synchronous generators. Inverter-based generation will also trip at 56.0 Hz.

Analyzing DG-PV performance during transmission faults requires a dynamic 3-phase model from the transmission system to the distribution system so single-phase distribution system voltages can be accurately simulated. Complex load models must also be developed since load characteristics will impact transient voltage stability.

Potential mitigating strategies include the following:

Limit the area of impact. The O'ahu system is more vulnerable to system collapse when central station generation is concentrated on the Leeward side of the island because a three-phase fault between Leeward O'ahu and Honolulu basically syncs the system's voltage source to ground. Sensitivity analysis indicates that running synchronous units at Waiau limits the number of transmission circuit faults that will collapse the system. Mitigation strategies at the distribution system should also be evaluated.

Increase the magnetic strength of the system. Transient voltage stability is maintained by increasing the short circuit current capacity on the transmission system. Short circuit ratio analysis should be performed for each critical bus to ensure voltage stability. The synchronous condenser requirements established in this PSIP only ensures that the protective relays will operate and the system's reactive power requirements for each resource plan is met; it doesn't ensure transient voltage stability.

Add frequency response reserves. Frequency response reserves can help stabilize system frequency for both the momentary loss of DG-PV, and the ultimate trip of all DG-PV. As stated above, at some point in time the capacity of DG-PV will be too high and frequency response reserves will be too costly or ineffective.

Improve inverter performance. The inverter industry is in the best position to mitigate this problem. Under-voltage ride-through requirements are nebulous; presently defined as "Permissive Operation" where the inverter manufacturer must remain connected to the grid but inverter output current can range from zero to full output.

Minimum Fault Current

Minimum fault current analysis was performed for the April PSIP. For O'ahu, 515 MVA at the 138 kV system is required. This ensures protective relay schemes will operate but this does not ensure transient voltage stability is maintained.

QV Analysis

The O'ahu transmission system is designed to operate with two transmission lines out of service (N-2) while maintaining a minimum bus voltage of 0.92 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide fault current to meet the minimum 515 MVA requirement. Therefore, only synchronous condensers are evaluated in these analyses.

For O‘ahu, the critical busses with the highest MVAR demand are the Archer, Halawa, Ko‘olau, and Pukele substations. These critical busses determine the reactive power requirements for the system.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

For the Theme 5 No-DR resource plan, analysis was performed to determine the capacities of FFR1, FFR2, and PFR required to bring the system into compliance with TPL-001. For the 5-year action plan period, sensitivity analysis was performed for a Kahe Unit 5 trip at full capacity. Table O-201 (page O-615) shows the results of the analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 120 MW for an AES trip and 90 MW for a Kahe 5 trip.

For the Post April DR resource plan, hourly capacities of FFR2 were provided to augment frequency response reserves. Analysis was performed to determine the capacities of FFR1 and PFR required to bring the system into compliance with TPL-001. Similar to the Theme 5 analysis, sensitivity analysis was performed for a Kahe Unit 5 trip at full capacity. Table O-202 (page O-615) shows the results of the analysis. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 70 MW for an AES trip and 30 MW for a Kahe 5 trip.

138 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system through the 5-year action plan. Results indicate that the system is susceptible to collapse on normally cleared three-phase faults in 2019. Breaker failure analysis produced similar results.

Non-exhaustive sensitivity analyses were performed for normally cleared faults to stabilize system frequency and bring the system into compliance with TPL-001. Strategies that were analyzed include 1) mitigate the loss of generation with the addition of PFR at 1% droop response, and 2) limit transient voltage impact by committing Waiau 7 and 8 in VPO. Both of these strategies improved system performance. Table O-74 shows the results of the PFR analysis to bring the system into compliance with TPL-001.

Year	PFR (MW)	
	No DR	DR
2019	440	350
2020	550	420
2021	740	440

Table O-74. Summary of Results PFR Analysis

Further analysis is required to determine optimal mitigating strategies to maintain system security.

MAUI SYSTEM SECURITY ANALYSIS

State of the System

The Maui system does not meet the requirements of TPL-001. Maui has three wind plants that total 72 MW that displaces synchronous generation. Maui operates with the minimum must-run units for the most of the year.

Analyses was conducted to evaluate the Maui system to determine technology-neutral system security requirements to maintain system stability and meet TPL-001.

Minimum Fault Current

A minimum fault current analysis was not performed for this PSIP. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Maui transmission system requires 72 MVA on the 69 kV system and 30 MVA on the 23 kV system. This requirement presumes protective relay schemes are currently operating as designed. This does not ensure the system has sufficient fault current to meet transient voltage stability requirements. More analysis is required to ensure protective relay schemes are operational and transient voltage stability is maintained.

Historical Contingency Events

On March 1, 2012, the system experienced the loss of two Maʻalaea generating units that tripped offline. The total system generation prior to the event was 155 MW. Maʻalaea M16 generating unit breaker opened at 13:32:35 with an output of 19.7 MW. The frequency decreased to 58.4 Hz and tripped Block 1 & 2 on UFLS for the frequency to recover. After a short recovery, M19 tripped offline with an output of 20.2 MW. The loss of M19 decreased the frequency to 57.7 Hz and triggered Block 3 on UFLS.

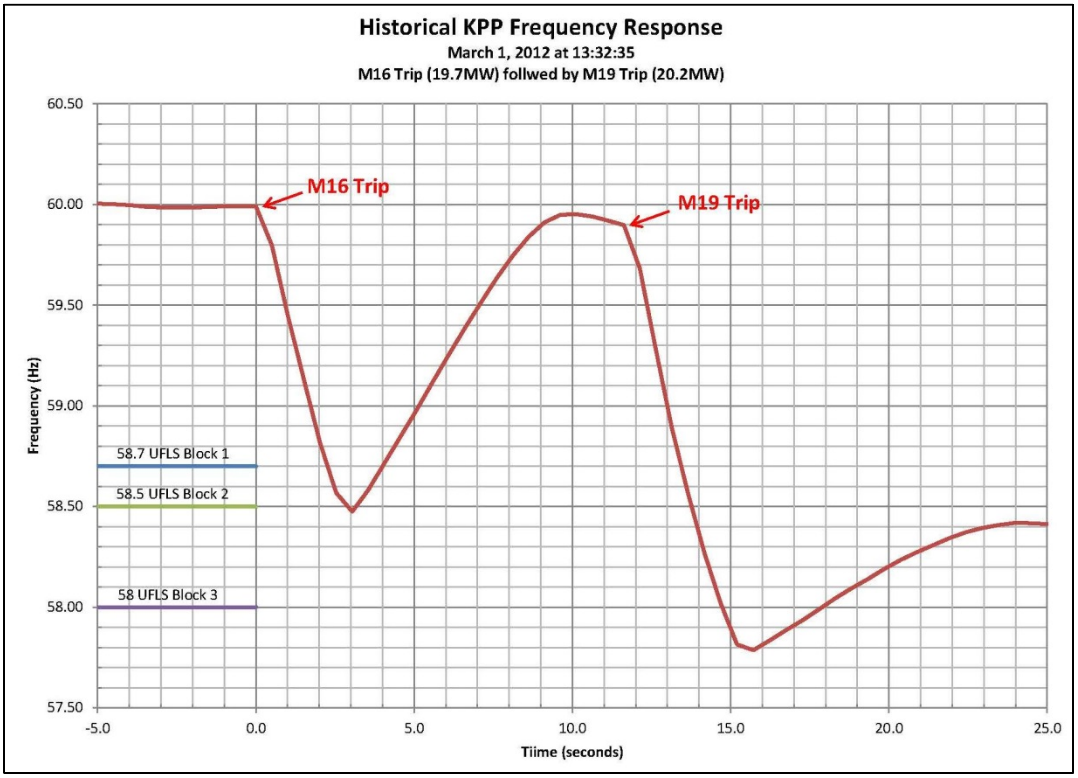

Figure O-193. Frequency Response Profile for Historic Events

Figure O-193 shows the frequency response profile for the M16 and M19 trip. The M16 trip causes the frequency nadir to breach 58.5 Hz that required 2 blocks of UFLS to stabilize system frequency.

2017

Loss of Generation Simulation

System security analysis was performed on two hours that were selected from the Theme 3 (a no-LNG case) production cost simulations that represents a typical hour and a boundary condition.

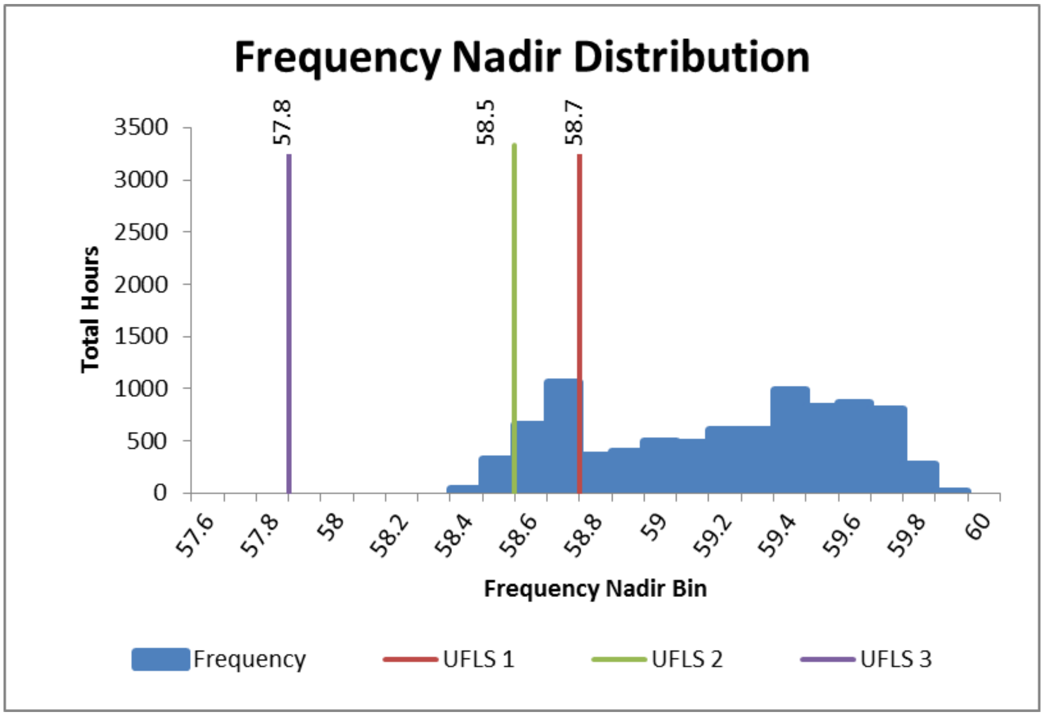

Figure O-194. Frequency Nadir Histogram 2017

Figure O-194 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year in 2017. The typical hour selected from the maximum distribution of 323 hours was2:00 PM on Wednesday, June 17. The frequency nadir range for the typical hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 44 hours was 4:00 AM on Friday, September 1. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

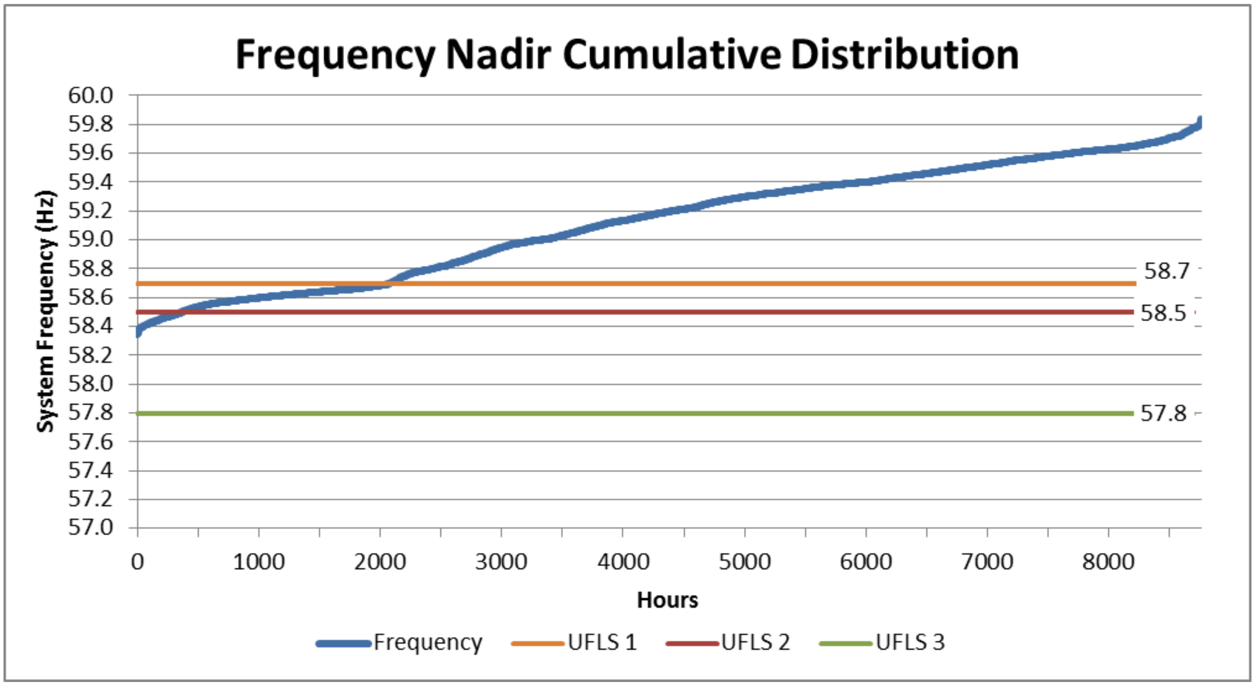

Figure O-195. Frequency Nadir Distribution Curve 2017

Figure O-195 shows the frequency nadir duration curve for 2017. The system is at risk of exceeding the UFLS requirements of TPL-001 for 367 hours of the year.

Unit	Unit Ratings					Current System - KWP I Trip Typical Wed 6/7/2017 Hour 14			Current System - KWP I Trip Boundary Fri 9/1/2017 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	10.0	1.5	7.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0			
Maalaea 14	20.0	5.9	2.02	26.8	58	11.6	8.4	5.7	7.5	12.5	1.6
Maalaea 15	13.0	3.0	2.46	18.5	46	4.4	8.6	1.4	5.0	8.0	2.0
Maalaea 16	20.0	5.9	2.02	26.8	54				7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54				19.5	0.0	13.6
Maalaea 18	12.8	3.0	2.46	18.5	46				7.5	5.3	4.5
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Total Wind	72					72			51		
-KWP	30	0				30			30		
-Auwahi	21	0				21					
-KWPII	21	0				21			21		
Central PV	5.74	0				5					
DG-PV	113	0				84					
Total System MVA							76			133	
Total Kinetic Energy							246			346	
Total Load							185			110	
Total Thermal Generation							26			57	
Total Renewable Generation							161			51	
Total Generation							187			108	
Excess Generation							2			-2	
Regulation Requirement							0			0	
Total Up Regulation							30			40	
Total Down Regulation							11			23	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.4	59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		51.6	60.5Hz Output		0.0

Table O-75. Unit Commitment and Dispatch 2017

Table O-75 shows the unit commitment and dispatch schedules for the typical hour (6/7/17, 2:00 PM) and boundary hour (9/1/17, 4:00 AM).

Simulations were performed to determine system performance for the largest loss of generation contingency for the typical and boundary hours. For Maui, the largest loss of generation contingency is a KWP I trip at 30 MW.

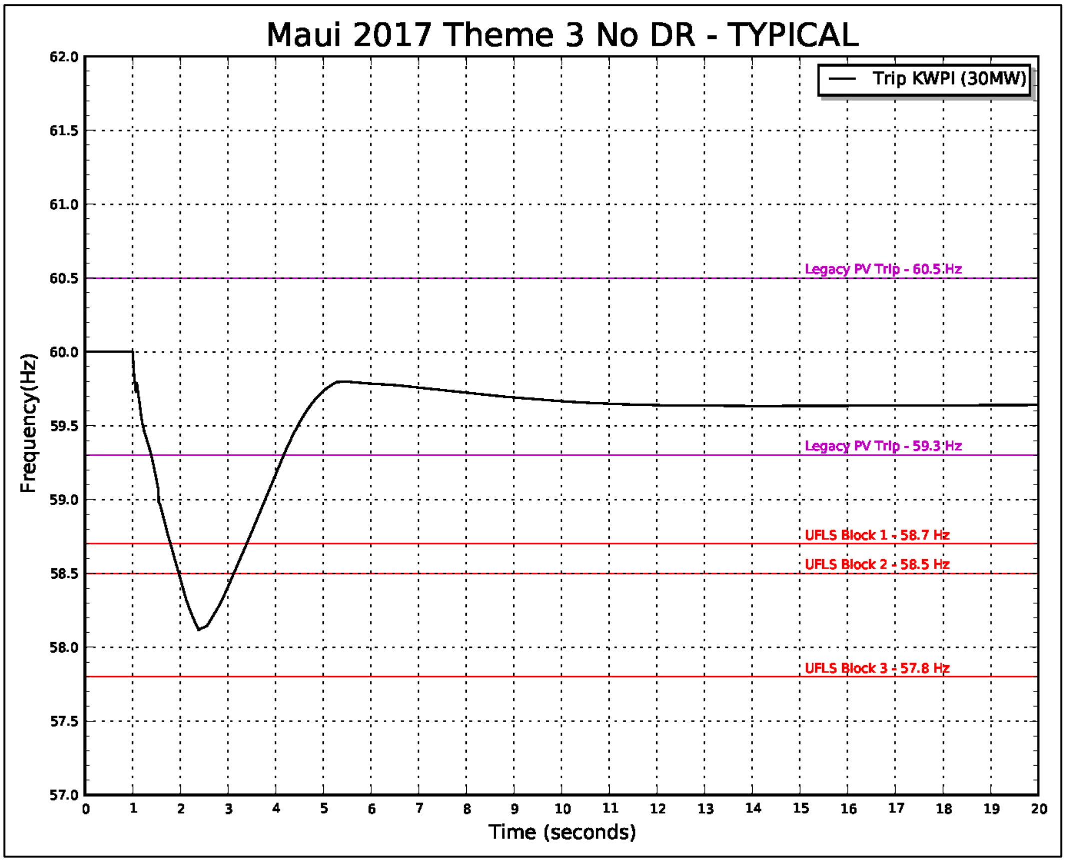

Figure O-196. Frequency Response Profile Typical Hour

Figure O-196 shows the frequency response profile for an AES turbine trip for a typical hour. System kinetic energy is 246 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.4 MW. The frequency nadir is 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The system is not in compliance with TPL-001.

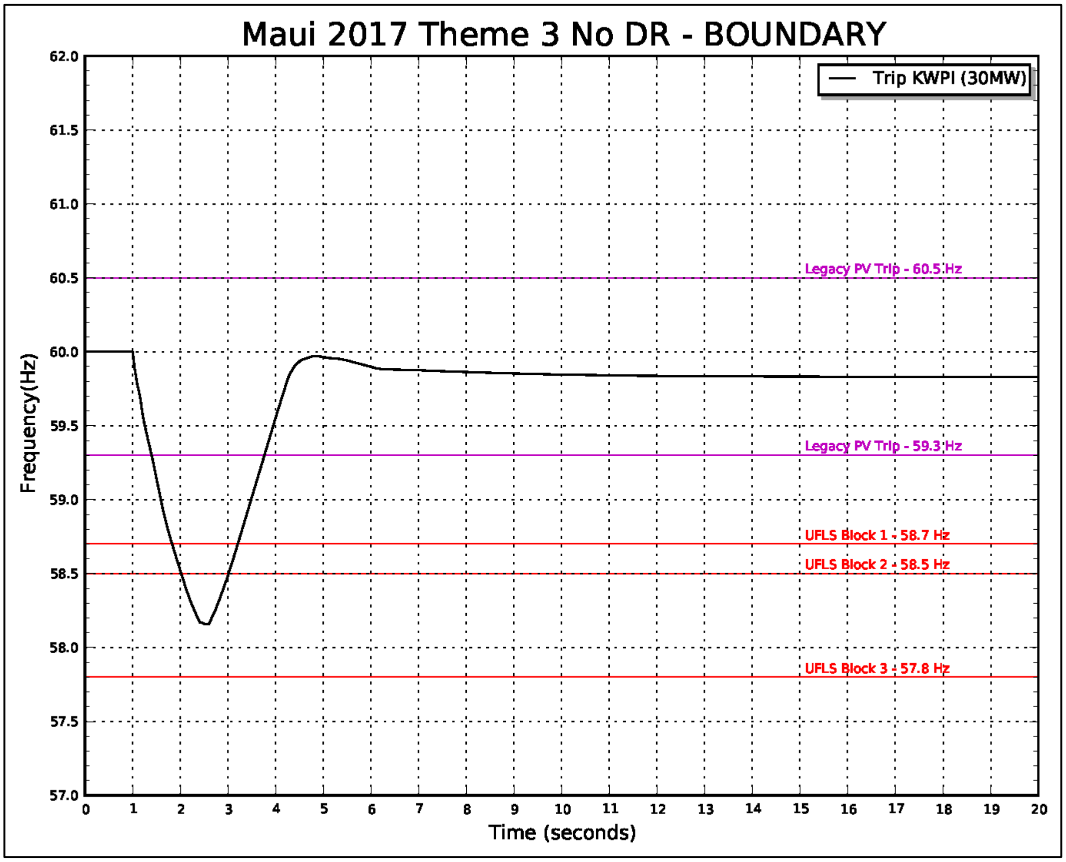

Figure O-197. Frequency Response Profile Boundary Hour

Figure O-197 shows the frequency response profile for the boundary hour. The frequency nadir is 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The system is not in compliance with TPL-001.

69 kV Fault Simulation

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. For Maui, normally cleared faults are isolated in 5-cycles at the near end and up to 30-cycles at the far end. Therefore, a normally cleared fault at the far end of the circuit constitutes a delayed clearing fault.

Unit	Unit Ratings					Current System - Fault Dispatch Thu 6/1/2017 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	11.6	8.4	5.7
Maalaea 15	13.0	3.0	2.46	18.5	46	4.4	8.6	1.4
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54	12.3	7.3	6.4
Maalaea 18	12.8	3.0	2.46	18.5	46	4.3	8.5	1.3
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	72					38		
-KWP	30	0				8		
-Auwahi	21	0				17		
-KWPII	21	0				13		
Central PV	5.74	0						
DG-PV	113	0				97		
Total System MVA						122		
Total Kinetic Energy						346		
Total Load						179		
Total Thermal Generation						43		
Total Renewable Generation						135		
Total Generation						178		
Excess Generation						-1		
Regulation Requirement						0		
Total Up Regulation						46		
Total Down Regulation						19		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		6.2
	60.5Hz Capacity			69.5		60.5Hz Output		59.6

Table O-76. Unit Commitment and Dispatch Fault Analysis 2017

Table O-76 shows the unit commitment and dispatch for the 69 kV fault analysis (6/1/17, 12:00 PM). Inverter-based generation is 97 MW.

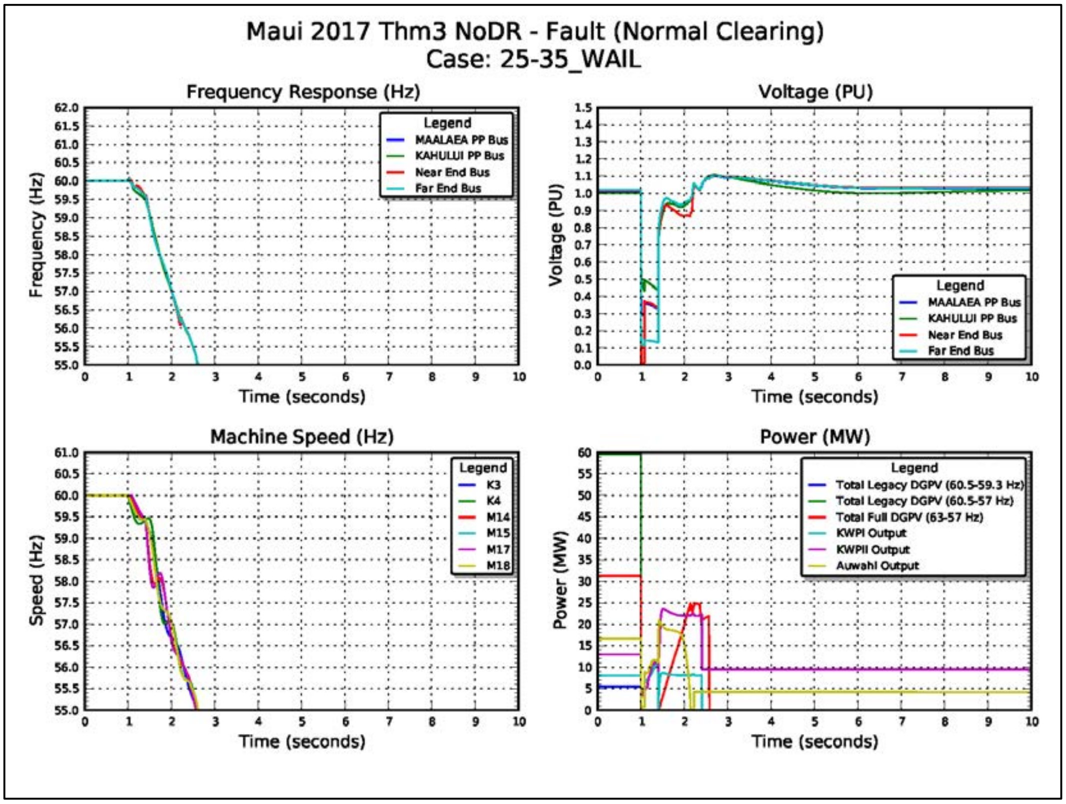

Figure O-198. System Performance for Normally Cleared Fault

Figure O-198 shows the system performance for a normally cleared fault at the Wailea end of the Wailea-Kihei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 97 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Maui 2019 Theme 3 No DR Fault Analysis		
Line	3-phase Fault Near	System Status Normal Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable
	Waiinu	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable
	Kanaha	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable
	Waiinu	Stable
Wailea-Kihei 69kV	Wailea	Unstable
	Kihei	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable
	Lahainaluna	Unstable
MPP-Kihei 69kV	MPP	Stable
	Kihei	Stable
MPP-Waiinu 69kV	MPP	Stable
	Waiinu	Unstable
MPP-Puunene 69kV	MPP	Stable
	Puunene	Unstable
MPP-KWPII 69kV	MPP	Stable
	KWPII	Stable
MPP-KWP 69kV	MPP	Stable
	KWP	Stable
MPP-Lahainaluna 69kV	MPP	Stable
	Lahainaluna	Stable
MPP-Kula AG 69kV	MPP	Stable
	Kula AG	Unstable
Kealahou-Kula 69kV	Kealahou	Stable
	Kula	Unstable
Kealahou-Kula AG 69kV	Kealahou	Unstable
	Kula AG	Unstable
KPP-Kanaha FDR1 23kV	KPP	Stable
	Kanaha FDR1	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable
	Kanaha FDR2	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable
	Kanaha FDR3	Stable
KPP-Wailuku 23kV	KPP	Stable
	Wailuku	Stable
Kanaha-Puunene 23kV	Kanaha	Stable
	Puunene	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable
	Pukalani	Unstable
Kanaha-Puunene 69kV	Kanaha	Stable
	Puunene	Stable
Kula-Pukalani 69kV	Kula	Stable
	Pukalani	Stable

Table O-77. Summary of Results Fault Simulation

Table O-77 is the summary of results for the breaker failure analysis. Fifteen simulations resulted in system instability where system voltage drops below the 0.5 PU voltage threshold for inverter-based generation to trip.

Post April No DR Plan –Theme 3

System security analysis performed on the Theme 3 resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

System security analysis was performed on the Theme 3 resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Maui transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirements of 73 MVA on the 69 kV system and 29 MVA on the 23 kV system. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Mon 12/30/2019 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	11.5	0.0	8.5
Kahului 4	11.5	3.0	3.48	15.6	54	10.4	1.2	7.4
Maalaea 14	20.0	5.9	2.02	28.8	58	20.0	0.0	14.1
Maalaea 15	13.0	5.0	2.46	18.5	46	13.0	0.0	8.0
Maalaea 16	20.0	5.9	2.02	26.8	54	20.0	0.0	14.1
Maalaea 17	19.5	5.9	2.02	26.8	54	19.5	0.0	13.6
Maalaea 18	12.8	3.0	2.46	18.5	46	13.6	-0.8	10.6
Maalaea 19	19.5	5.9	2.02	26.8	54	19.5	0.0	13.6
Maalaea 10	12.3	7.9	3.28	15.6	51	12.2	0.1	4.3
Maalaea 12	12.3	7.9	3.28	15.6	51	12.2	0.1	4.3
Maalae13	12.3	7.9	3.28	15.6	51	12.3	0.0	4.5
Maalaea 11	12.3	7.9	3.28	15.6	51	12.1	0.2	4.2
Maalaea 4	5.5	1.9	2.28	7.0	16	4.0	1.5	2.1
Maalaea 6	5.5	1.9	2.28	7.0	16	4.4	1.1	2.6
Maalaea 9	5.5	1.9	2.28	7.0	16	3.8	1.7	2.0
Maalaea 8	5.5	1.9	2.28	7.0	16	4.4	1.1	2.5
Maalaea 5	5.5	1.9	2.28	7.0	16	4.4	1.1	2.6
Maalaea 1	2.5	2.3	0.83	3.4	3	2.3	0.3	0.0
Maalaea 3	2.5	2.5	0.83	3.4	3	2.5	0.0	0.0
Maalaea 2	2.5	2.5	0.83	3.4	3	2.5	0.0	0.0
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16	4.7	0.3	4.7
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	72					0		
-KWP	30	0						
-Auwahi	21	0						
-KWPII	21	0						
DG-PV	121	0						
DER Grid Ex	4.2	0						
Total System MVA							289	
Total Kinetic Energy							764	
Total Load							209	
Total Thermal Generation							209	
Total Renewable Generation							0	
Total Generation							209	
Excess Generation							0	
Regulation Requirement							0	
Total Up Regulation							8	
Total Down Regulation							103	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		0.0

Table O-78. Unit Commitment and Dispatch 2019 QV Analysis

Table O-78 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Mon 12/30/2019 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	0.0	7.1	0.0
Kahului 4	9.4	0.0	0.0	9.4	0.0
Maalaea 14	4.1	0.0	4.0	0.2	4.0
Maalaea 15	2.9	0.0	1.4	1.5	1.4
Maalaea 16	4.1	0.0	1.4	2.7	1.4
Maalaea 17	15.0	0.0	1.4	13.6	1.4
Maalaea 18	12.0	0.0	1.4	10.6	1.4
Maalaea 19	15.0	0.0	1.4	13.6	1.4
Maalaea 10	9.4	0.0	0.0	9.4	0.0
Maalaea 12	9.4	0.0	0.7	8.7	0.7
Maalaea13	9.4	0.0	0.7	8.7	0.7
Maalaea 11	2.0	0.0	0.0	2.0	0.0
Maalaea 4	4.2	0.0	0.2	4.0	0.2
Maalaea 6	4.2	0.0	0.5	3.7	0.5
Maalaea 9	4.2	0.0	0.4	3.8	0.4
Maalaea 8	4.2	0.0	0.2	4.0	0.2
Maalaea 5	4.2	0.0	0.2	4.0	0.2
Maalaea 1	1.9	0.0	0.2	1.7	0.2
Maalaea 3	1.9	0.0	0.2	1.6	0.2
Maalaea 2	1.9	0.0	0.2	1.6	0.2
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0	0.0	3.0	0.0
Kahului 2	3.0	0.0			
Total Wind	31.2	0.0			
-KWP	14.5	-0.2			
-Auwahi	6.5	-6.5			
-KWPII	10.2	0.0			
DG-PV	0.0	0.0			
Total Thermal MVAR Generation			14.6		
Total Renewable MVAR Generation			0.0		
Total Cap Bank MVAR			54.4		
Charging MVAR			5.3		
Total MVAR Supply			74.4		
Total MVAR Load			33.0		
Total MVAR Losses			41.3		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				115	
Total MVAR Absorb Capability					14.6

Table O-79. MVAR Capability 2019 QV Analysis

Table O-79 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	Maalaea-Kihei
104	Maalaea-Waiinu

Table O-80. N-1 Contingencies 2019 QV Analysis

Table O-80 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

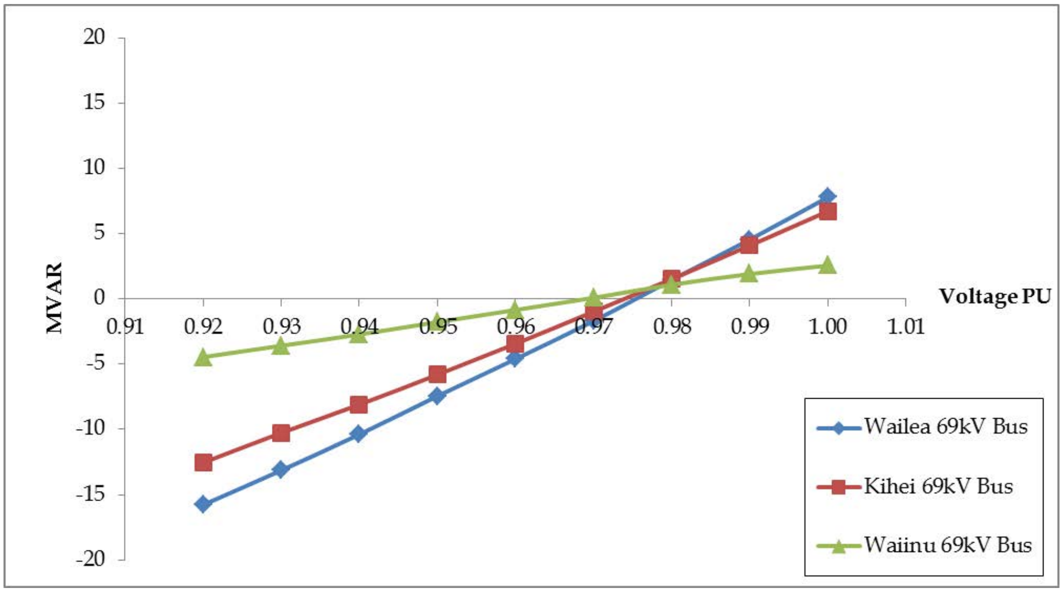

Figure O-199. QV Curves 2019

Figure O-199 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	102	8	102	5	102	1	102	-2	102	-5	102	-7	102	-10	102	-13	102	-16
35	Kihei 69 kV Bus	102	7	102	4	102	2	102	-1	102	-3	102	-6	102	-8	102	-10	102	-13
636	Waiinu 69 kV Bus	104	3	104	2	104	1	104	0	104	-1	104	-2	104	-3	104	-4	104	-4

Table O-81. Summary of Results 2019 QV Analysis

Table O-81 shows the results of the QV analysis for 2019. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

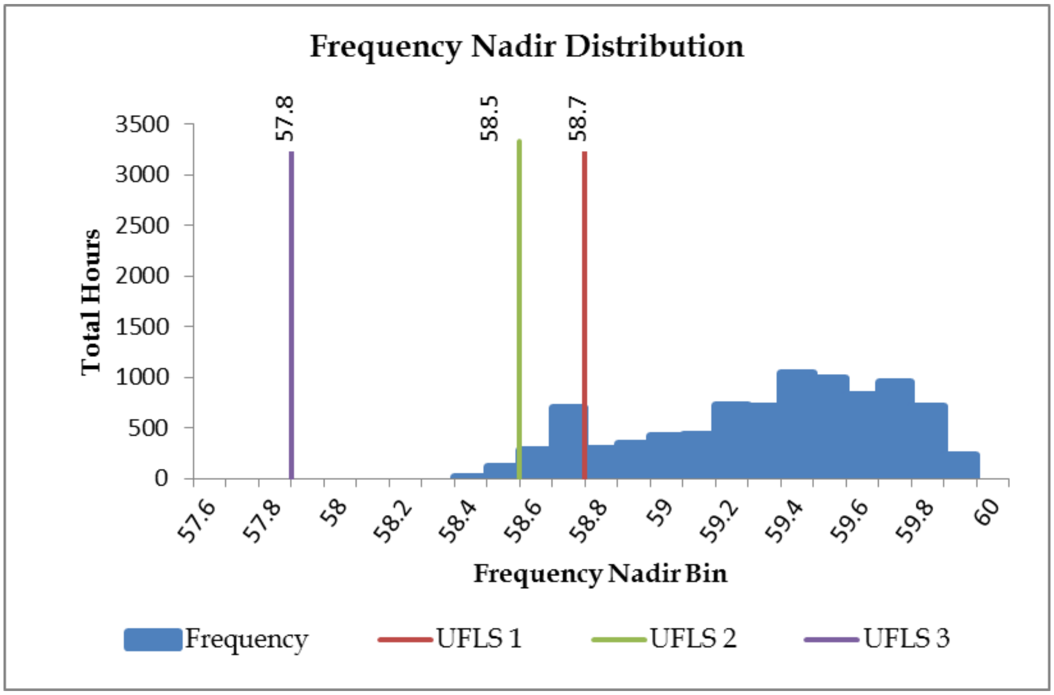

Figure O-200. Frequency Nadir Histogram for 2019

Figure O-200 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 211 hours was 1:00 PM on Friday, March 22. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 8 hours was 2:00 PM on Sunday, March 17. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

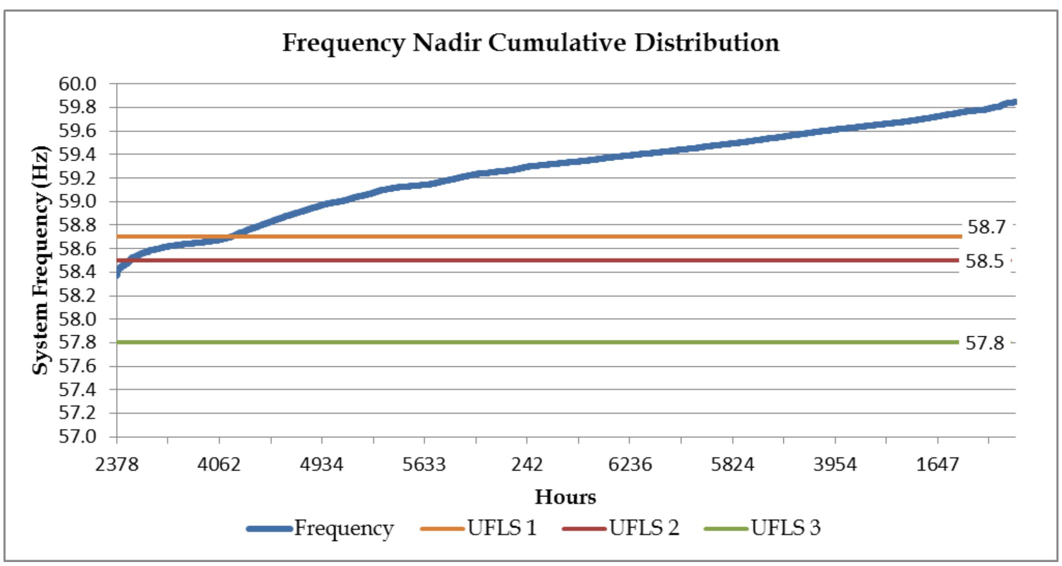

Figure O-201. Frequency Nadir Duration Curve 2019

Figure O-201 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of exceeding the UFLS requirements of TPL-001 for 8 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Fri 3/22/2019 Hour 13			Theme 3 - KWP I Trip Boundary Sun 3/17/2019 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	7.5	12.5	1.6	7.5	12.5	1.6
Maalaea 15	13.0	5.0	2.46	18.5	46	5.0	8.0	0.0	5.0	8.0	0.0
Maalaea 16	20.0	5.9	2.02	26.8	54	7.5	12.5	1.6	7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Total Wind	72					233%	49		63%	45	
-KWP	30	0					29			30	
-Auwahi	21	0								2	
-KWPII	21	0					20			13	
DG-PV	121	0				79%	96		76%	92	
DER Grid Ex	4.2	0				71%	3		71%	3	
Total System MVA							101			101	
Total Kinetic Energy							300			300	
Total Load							177			169	
Total Thermal Generation							30			30	
Total Renewable Generation							148			140	
Total Generation							178			170	
Excess Generation							1			1	
Regulation Requirement							0			0	
Total Up Regulation							33			33	
Total Down Regulation							3			3	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.7	59.3Hz Output		5.5
	60.5Hz Capacity			69.5		60.5Hz Output		55.1	60.5Hz Output		52.8

Table O-82. Unit Commitment and Dispatch 2019

Table O-82 shows the unit commitment and dispatch for the typical hour (3/22/19, 1:00 PM) and boundary hour (3/17/19, 2:00 PM).

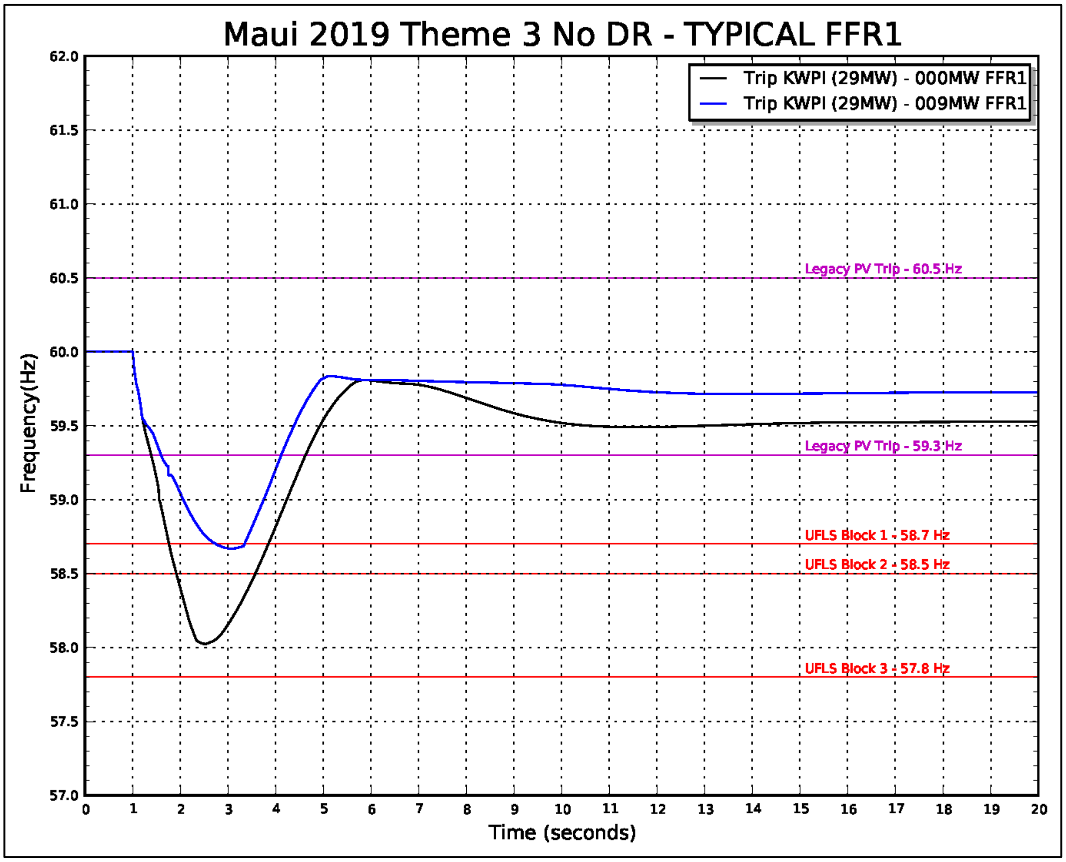

Figure O-202. Frequency Response Profile for FFR1 Typical Hour

Figure O-202 shows the frequency response profile for a KWP I trip at 29 MW for a typical hour. System kinetic energy is 300 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.7 MW. With no FFR, the frequency nadir is 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

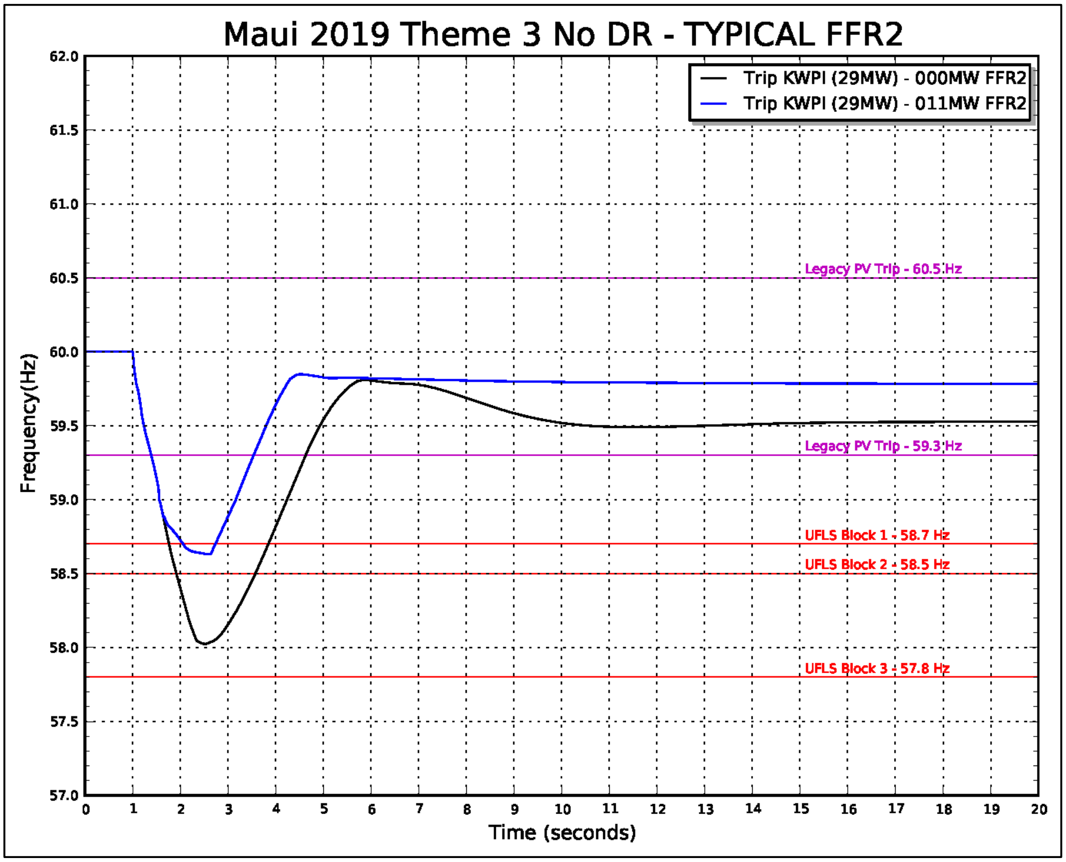

Figure O-203. Frequency Response Profile for FFR2 Typical Hour

Figure O-203 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 11 MW.

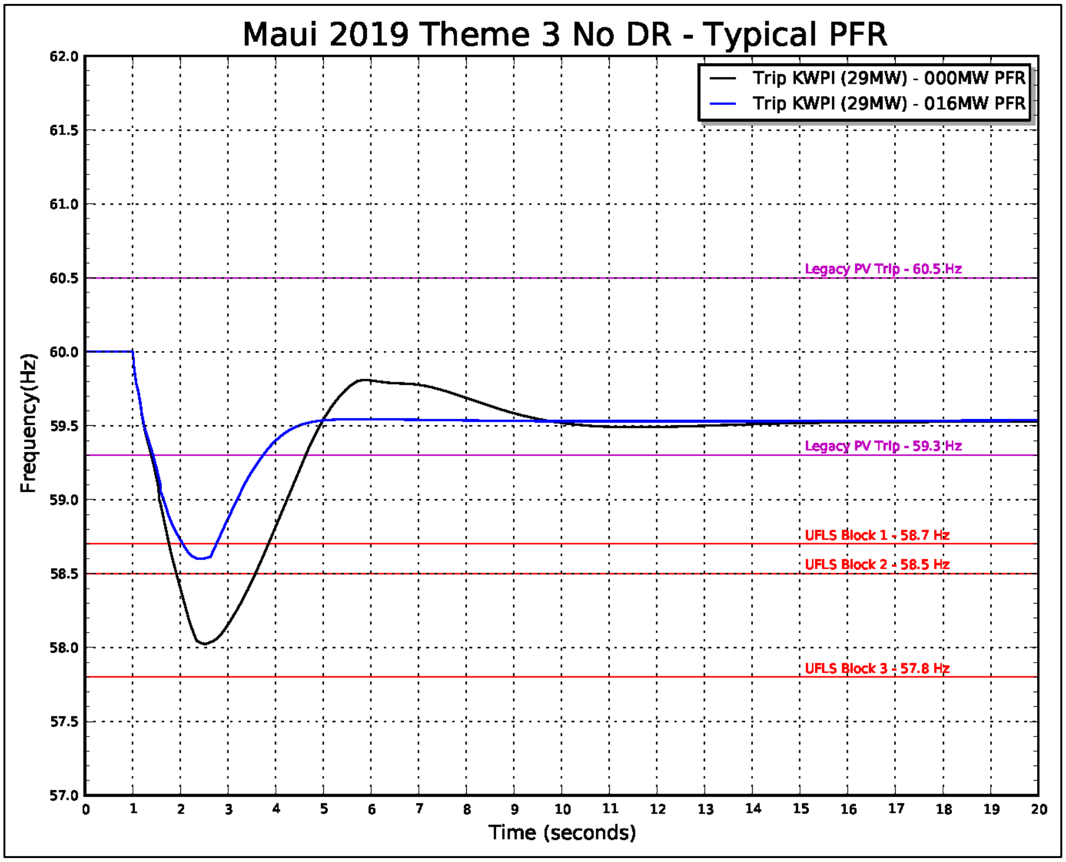

Figure O-204. Frequency Response Profile for PFR Typical Hour

Figure O-204 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 16 MW. This is in addition to the 33 MW of upward regulation from thermal generation.

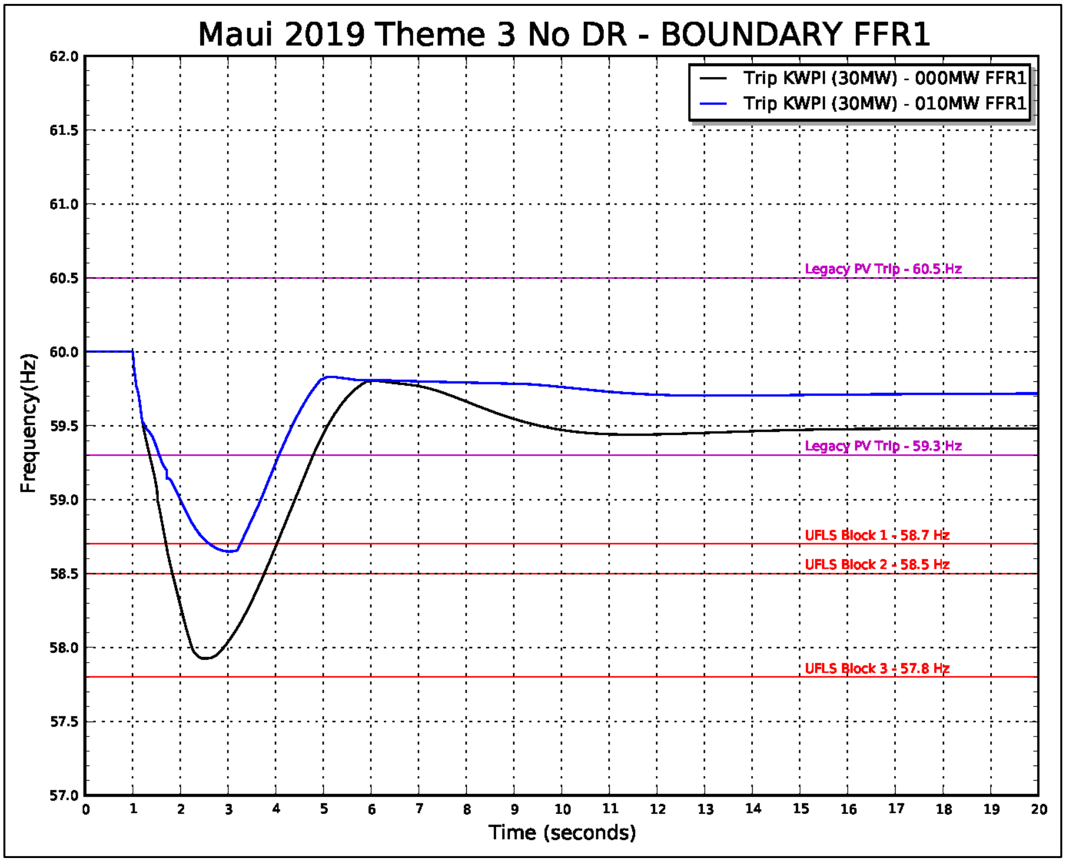

Figure O-205. Frequency Response Profile for FFR1 Boundary Hour

Figure O-205 shows the frequency response profile for a KWP I trip at 30 MW for a boundary hour. System kinetic energy is 300 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.5 MW. With no FFR, the frequency nadir is 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 10 MW.

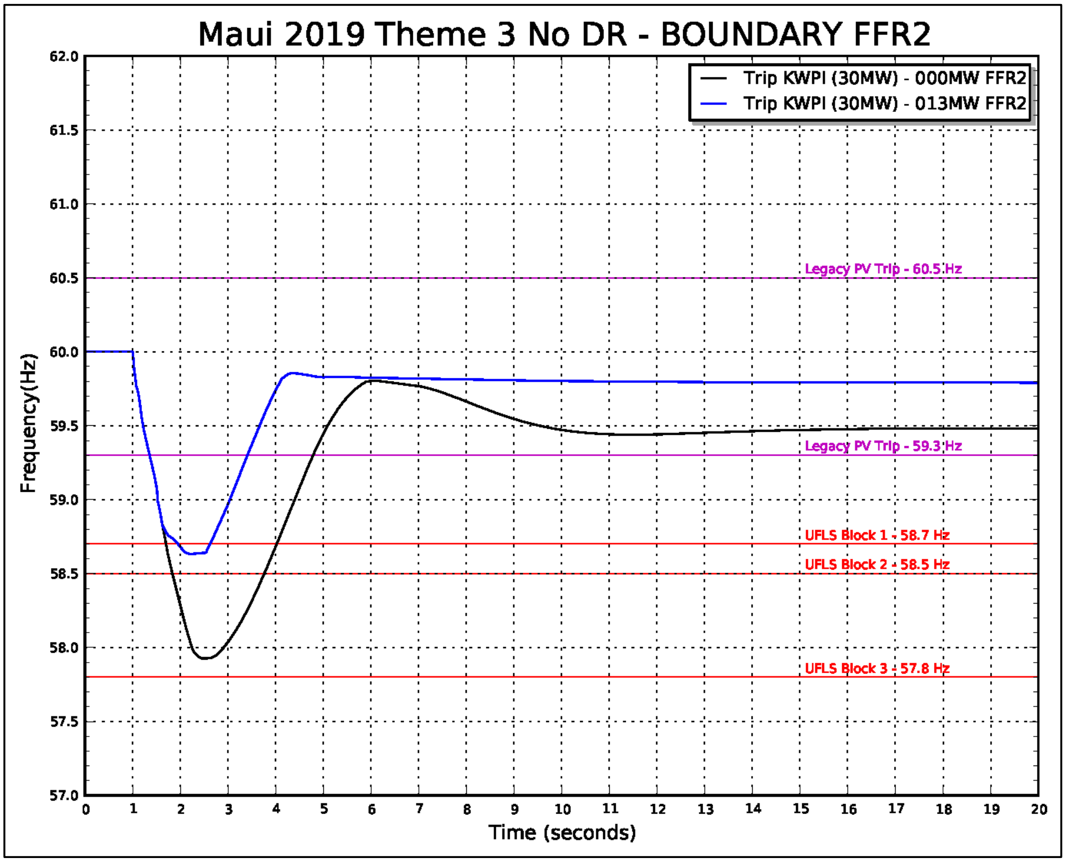

Figure O-206. Frequency Response Profile for FFR2 Boundary Hour

Figure O-206 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW.

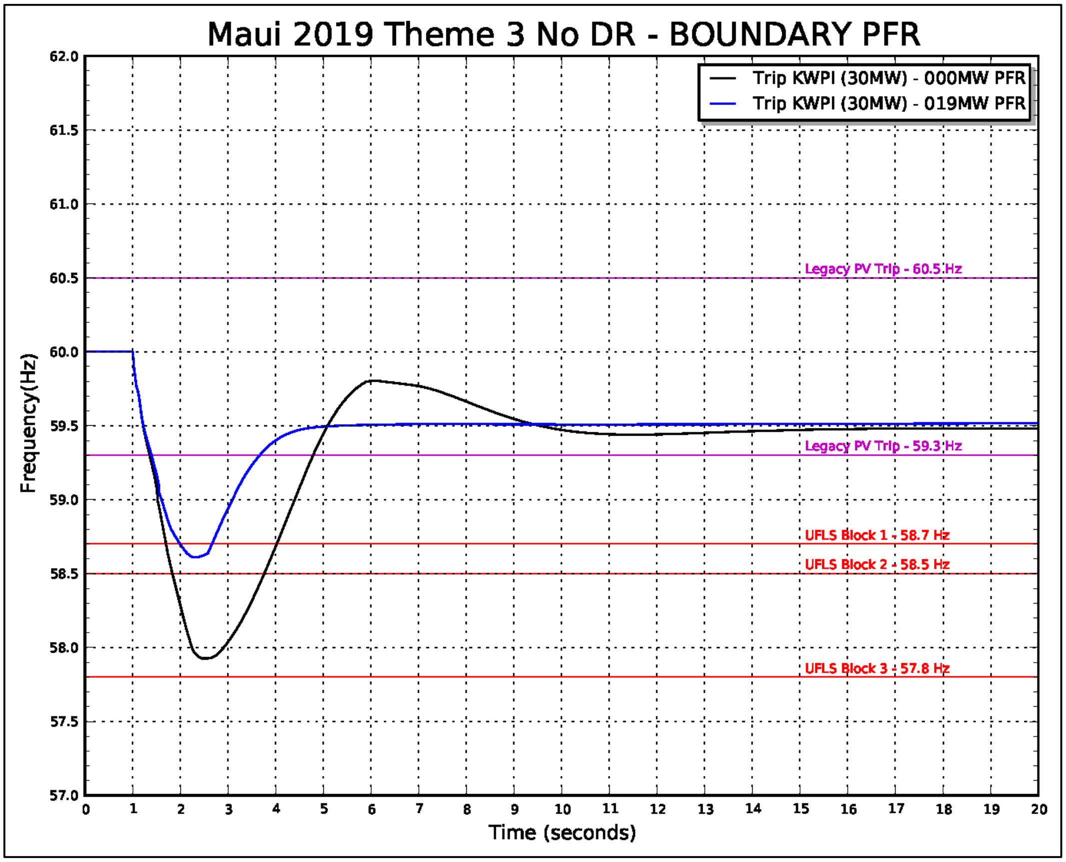

Figure O-207. Frequency Response Profile for PFR Boundary Hour

Figure O-207 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 19 MW. This is in addition to the 46 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					Theme 3 - Fault Sun 3/27/2019 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	8.5	11.5	2.6
Maalaea 15	13.0	5.0	2.46	18.5	46	6.0	7.0	1.0
Maalaea 16	20.0	5.9	2.02	26.8	54	8.5	11.5	2.6
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51	8.0	4.3	0.1
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	72					105%	22	
-KWP	30	0						
-Auwahi	21	0					21	
-KWPII	21	0					1	
DG-PV	121	0				85%	103	
DER Grid Ex	4.2	0				71%	3	
Total System MVA							117	
Total Kinetic Energy							352	
Total Load							173	
Total Thermal Generation							41	
Total Renewable Generation							128	
Total Generation							169	
Excess Generation							-4	
Regulation Requirement							0	
Total Up Regulation							34	
Total Down Regulation							6	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		6.1
		60.5Hz Capacity		69.5		60.5Hz Output		59.2

Table O-83. Unit Commitment and Dispatch Fault Analysis 2019

Table O-83 shows the unit commitment and dispatch for the 69 kV fault analysis (3/27/19, 1:00 PM). Inverter-based generation is 103 MW.

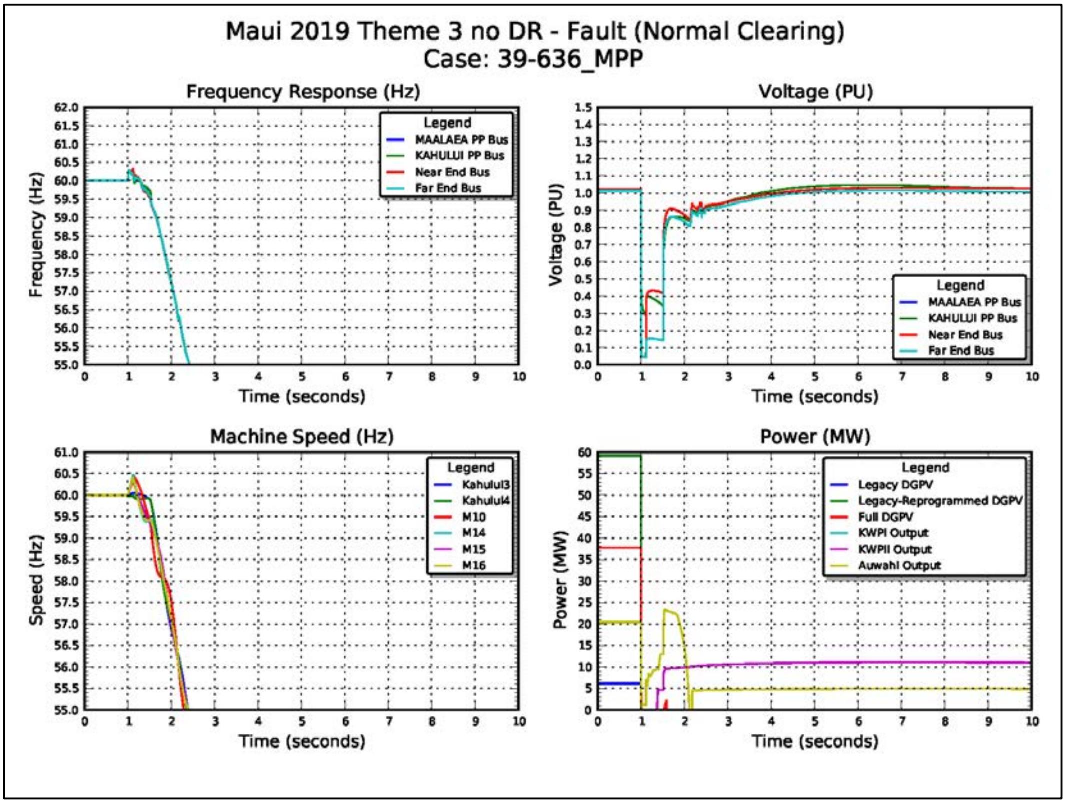

Figure O-208. System Performance for Normally Cleared Fault

Figure O-208 shows the system performance for a normally cleared fault at the Maʻalaea end of the Maʻalaea-Waiinu circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 103 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

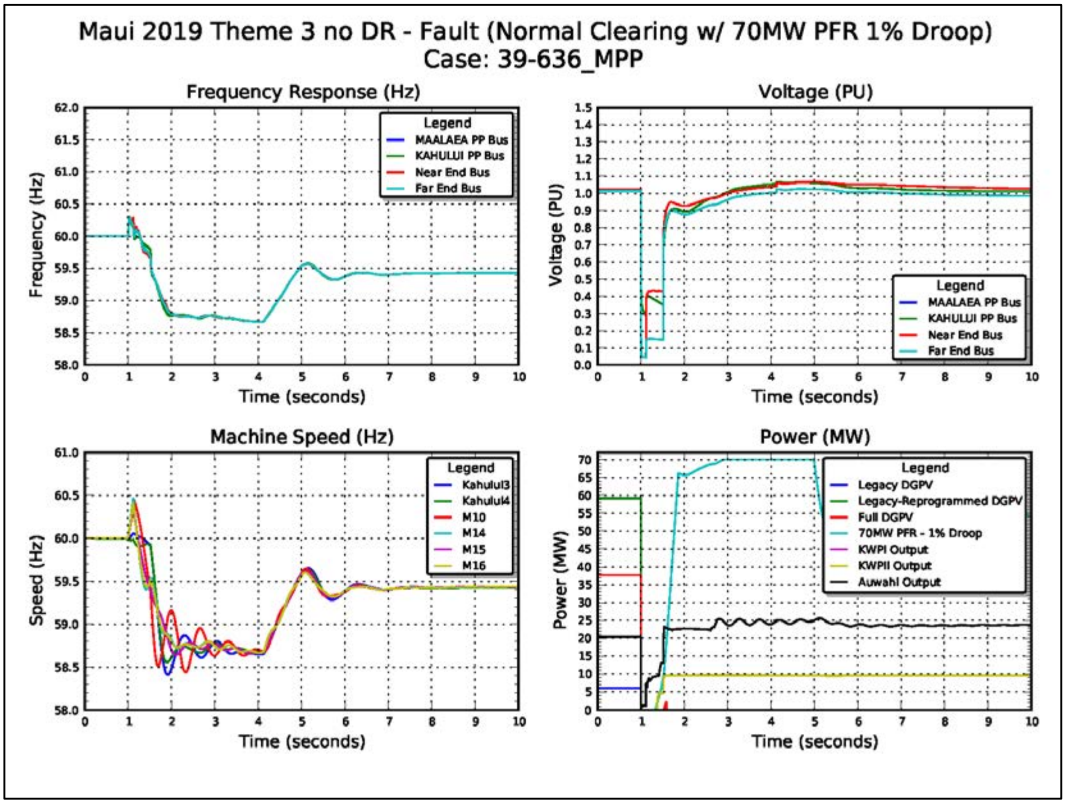

Figure O-209. Normally Cleared Fault Sensitivity 70 MW PFR

Figure O-209 shows system performance with the addition of the 70 MW PFR at 1 % droop response. For the purpose of this analysis, a 70 MW BESS located at Maʻalaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 70 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2019 Theme 3 No DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 70MW PFR	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Unstable	Stable	Stable
	Kanaha	Unstable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Stable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-84. Summary of Results Fault Analysis 2019

Table O-84 shows the results of the 69 kV fault analysis with 70 MW of PFR. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay

schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Mon 8/17/2020 Hour 20		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	4.5	7.0	1.5
Kahului 4	11.5	3.0	3.48	15.6	54	4.5	7.0	1.5
Maalaea 14	20.0	5.9	2.02	28.8	58	7.5	12.5	1.5
Maalaea 15	13.0	4.0	2.46	18.5	46	4.9	8.1	0.9
Maalaea 16	20.0	5.9	2.02	26.8	54	7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54	14.0	5.5	8.1
Maalaea 18	12.8	3.0	2.46	18.5	46	9.8	3.0	6.8
Maalaea 19	19.5	5.9	2.02	26.8	54	14.0	5.5	8.1
Maalaea 10	12.3	7.9	3.28	15.6	51	7.9	4.4	0.0
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16	2.3	2.7	2.3
Kahului 2	5.0	0.0	2.62	6.3	16	2.3	2.7	2.3
Total Wind	162					126		
-KWP	30	0				28		
-Auwahi	21	0				10		
-KWPII	21	0				20		
-New Wind 1	30	0				23		
-New Wind 2	30	0				23		
-New Wind 3	30	0				23		
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	125	0						
DER Grid Ex	4	0						
Total System MVA							204	
Total Kinetic Energy							538	
Total Load							206	
Total Thermal Generation							79	
Total Renewable Generation							126	
Total Generation							205	
Excess Generation							-1	
Regulation Requirement							0	
Total Up Regulation							52	
Total Down Regulation							27	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		0.0

Table O-85. Unit Commitment and Dispatch 2020 QV Analysis

Table O-85 shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Mon 8/17/2020 Hour 20		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	0.0	7.1	0.0
Kahului 4	9.4	0.0	0.0	9.4	0.0
Maalaea 14	4.1	0.0	3.8	0.3	3.8
Maalaea 15	2.9	0.0	0.4	2.5	0.4
Maalaea 16	4.1	0.0	2.0	2.1	2.0
Maalaea 17	15.0	0.0	4.0	11.0	4.0
Maalaea 18	12.0	0.0	2.0	10.0	2.0
Maalaea 19	15.0	0.0	4.0	11.0	4.0
Maalaea 10	9.4	0.0	0.0	9.3	0.0
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0	0.0	3.0	0.0
Kahului 2	3.0	0.0	0.0	3.0	0.0
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	0.0	14.5	0.2
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0	0.4	9.4	0.4
-New Wind 2	9.9	0.0	0.4	9.4	0.4
-New Wind 3	9.9	0.0	0.4	9.4	0.4
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			16.3		
Total Renewable MVAR Generation			1.3		
Total Cap Bank MVAR			54.0		
Charging MVAR			6.1		
Total MVAR Supply			77.6		
Total MVAR Load			32.4		
Total MVAR Losses			45.1		
Excess MVAR Generation			0.1		
Total MVAR Supply Capability				128	
Total MVAR Absorb Capability					16.3

Table O-86. MVAR Capability 2020 QV Analysis

Table O-86 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	MPP-Kihei 69 kV
104	MPP-Waiinu 69 kV
113	Wailea-Auwahi Tap 69 kV

Table O-87. N-1 Contingencies 2020 QV Analysis

Table O-87 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

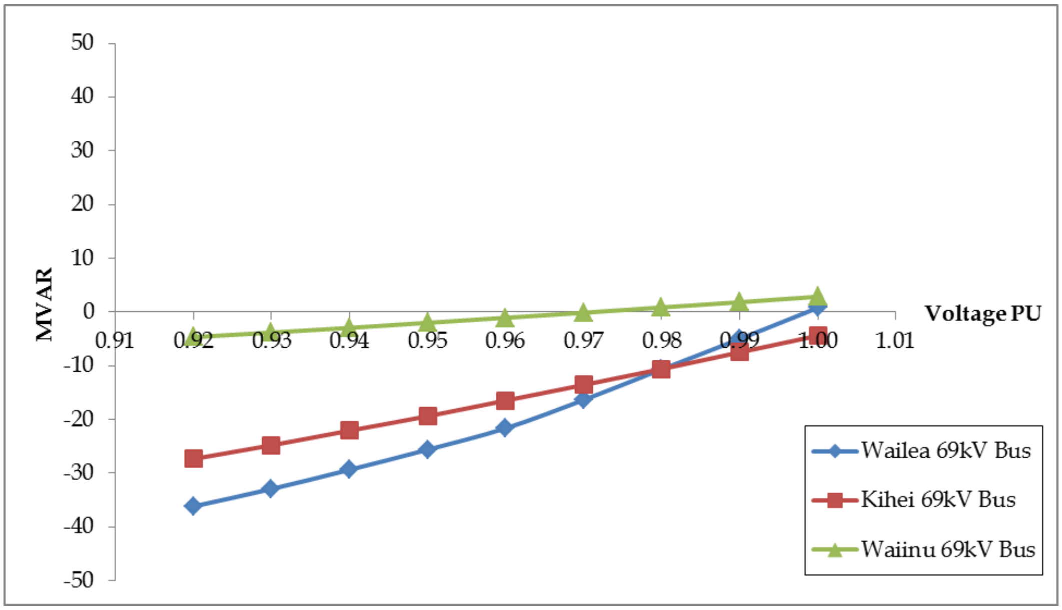

Figure O-210. QV Curves 2020

Figure O-210 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	113	1	113	-5	113	-11	113	-16	113	-22	102	-26	102	-29	102	-33	102	-36
35	Kihei 69 kV Bus	102	-4	102	-7	102	-11	102	-14	102	-16	102	-19	102	-22	102	-25	102	-27
636	Waiinu 69 kV Bus	104	3	104	2	104	1	104	0	104	-1	104	-2	104	-3	104	-4	104	-5

Table O-88. Summary of Results 2020 QV Analysis

Table O-88 shows the results of the QV analysis for 2020. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

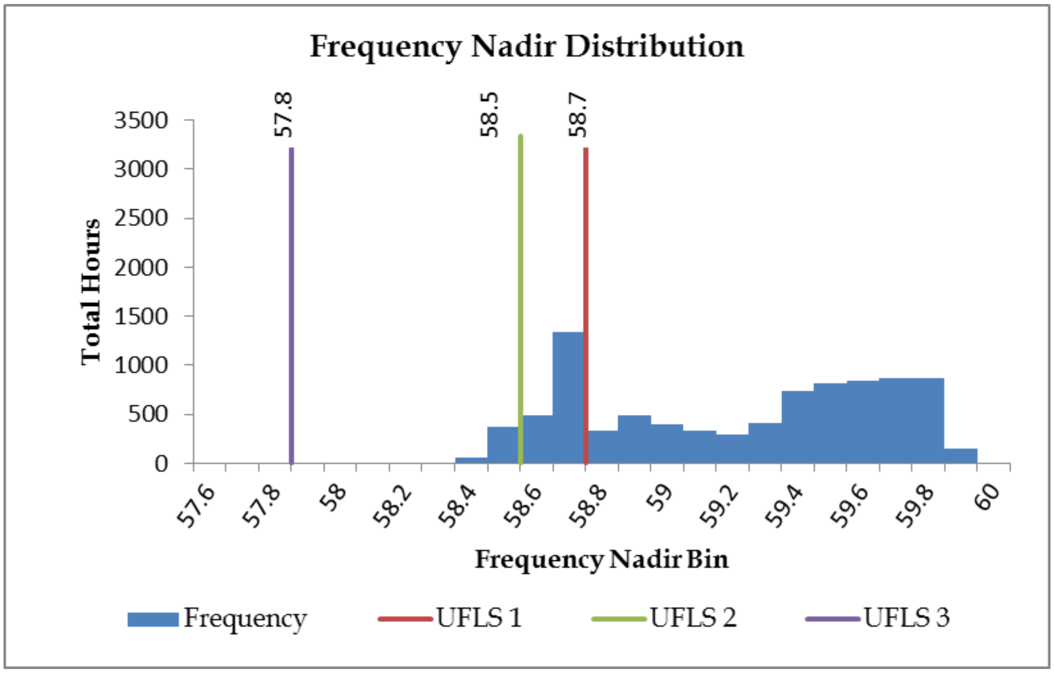

Figure O-211. Frequency Nadir Histogram for 2020

Figure O-211 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 374 hours was 12:00 PM on Monday, May 11. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 53 hours was 4:00 AM on Wednesday, November 25. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

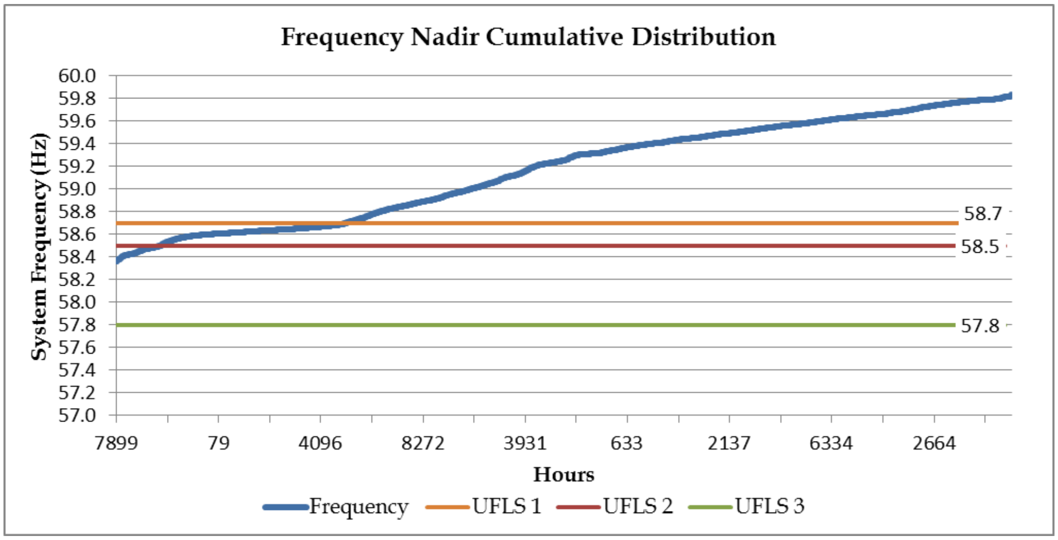

Figure O-212. Frequency Nadir Duration Curve 2020

Figure O-212 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of exceeding the UFLS requirements of TPL-001 for 403 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Mon 05/11/2020 Hour 12			Theme 3 - KWP I Trip Boundary Wed 11/25/2020 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0			
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	16.0	4.0	10.1	8.0	12.0	2.1
Maalaea 15	13.0	3.0	2.46	18.5	46				4.0	9.0	0.0
Maalaea 16	20.0	5.9	2.02	26.8	54				8.0	12.0	2.1
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	162					48			75		
-KWP	30	0				27			24		
-Auwahi	21	0									
-KWPII	21	0				21			20		
-New Wind 1	30	0							30		
-New Wind 2	30	0							1		
-New Wind 3	30	0									
Total Utility PV	80					2					
-Utility PV1	20	0				2					
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	125	0				99					
DER Grid Ex	4	0				5					
Total System MVA							58			90	
Total Kinetic Energy							305			316	
Total Load							180			99	
Total Thermal Generation							26			25	
Total Renewable Generation							154			75	
Total Generation							180			100	
Excess Generation							0			1	
Regulation Requirement							0			0	
Total Up Regulation							17			40	
Total Down Regulation							10			4	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.7	59.3Hz Output		0.0
	60.5Hz Capacity			69.5		60.5Hz Output		55.0	60.5Hz Output		0.0

Table O-89. Unit Commitment and Dispatch 2020

Table O-89 shows the unit commitment and dispatch for the typical hour (5/11/20, 12:00 PM) and boundary hour (11/25/20, 4:00 AM).

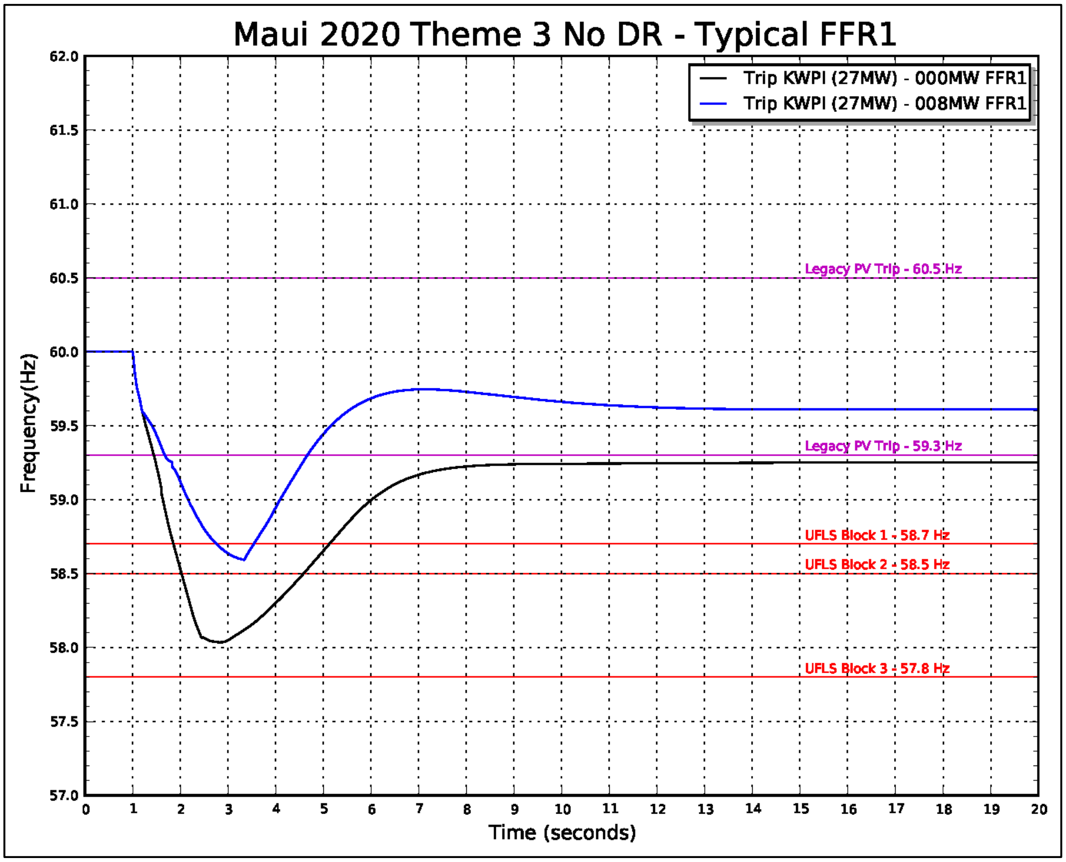

Figure O-213. Frequency Response Profile for FFR1 Typical Hour

Figure O-213 shows the frequency response profile for a KWP 1 trip at 27 MW for a typical hour. System kinetic energy is 305 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.7 MW. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

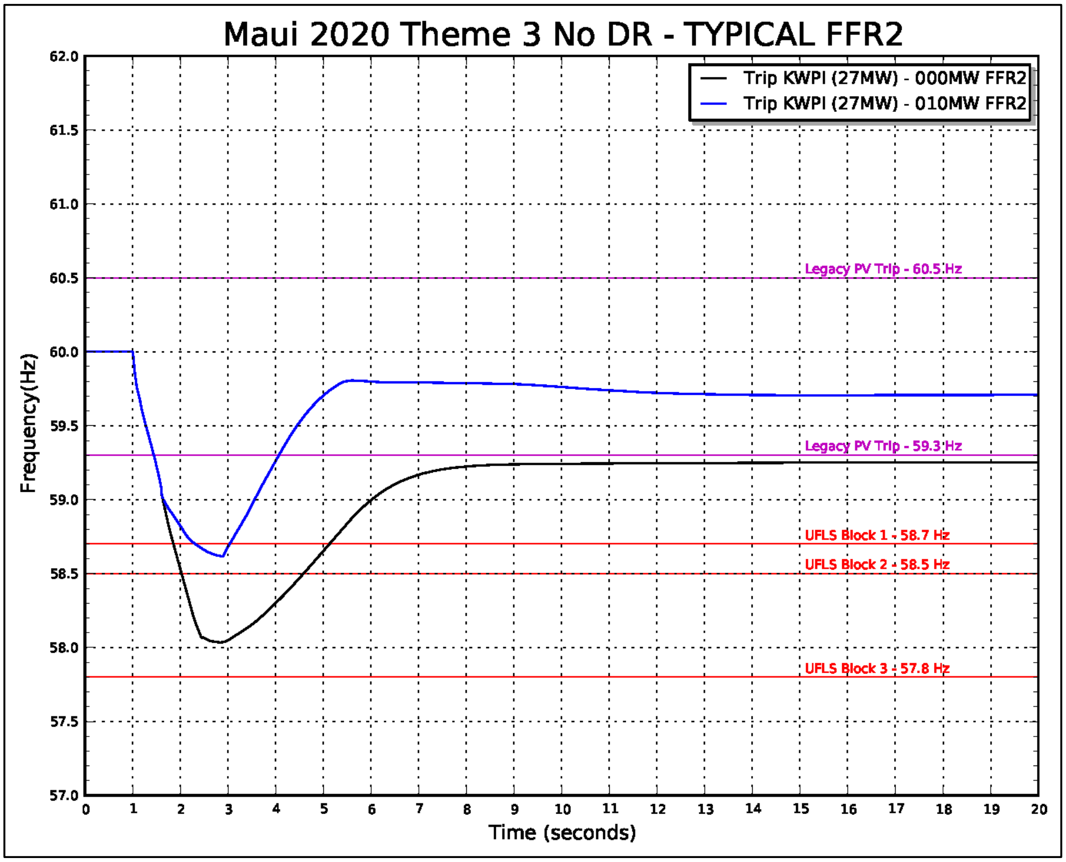

Figure O-214. Frequency Response Profile for FFR2 Typical Hour

Figure O-214 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 10 MW.

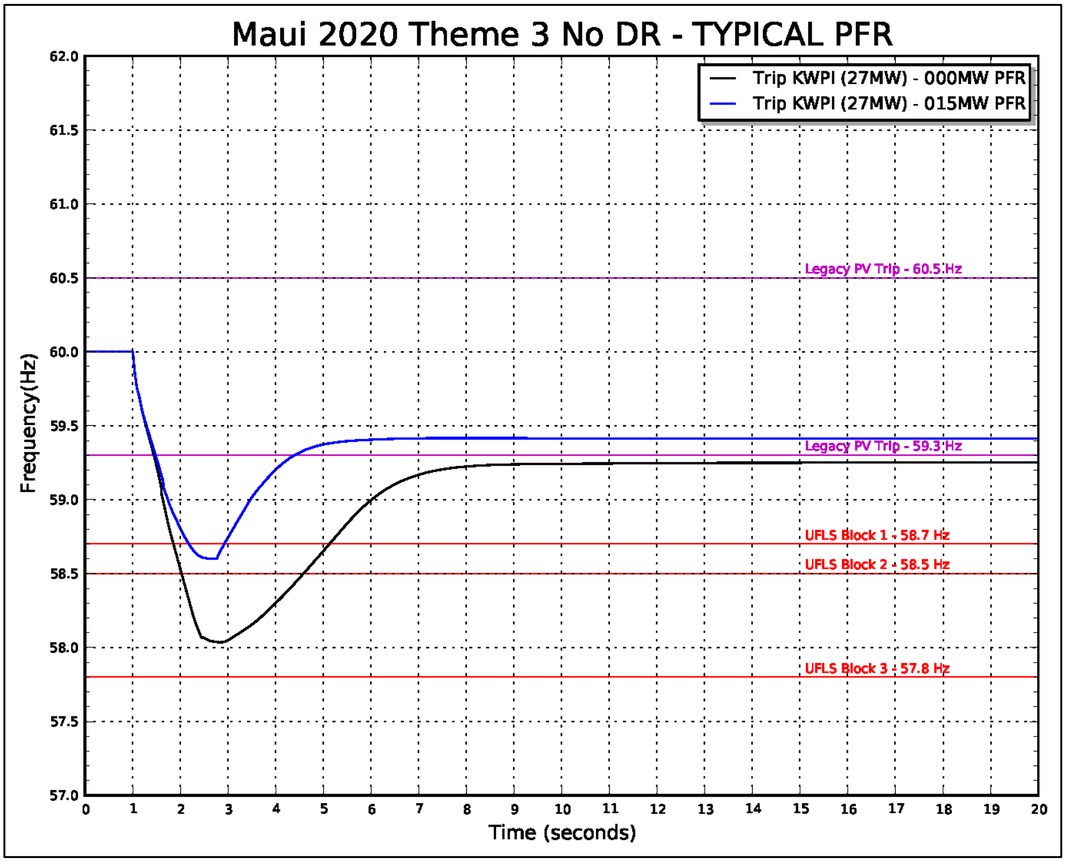

Figure O-215. Frequency Response Profile for PFR Typical Hour

Figure O-215 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 17 MW of upward regulation from thermal generation.

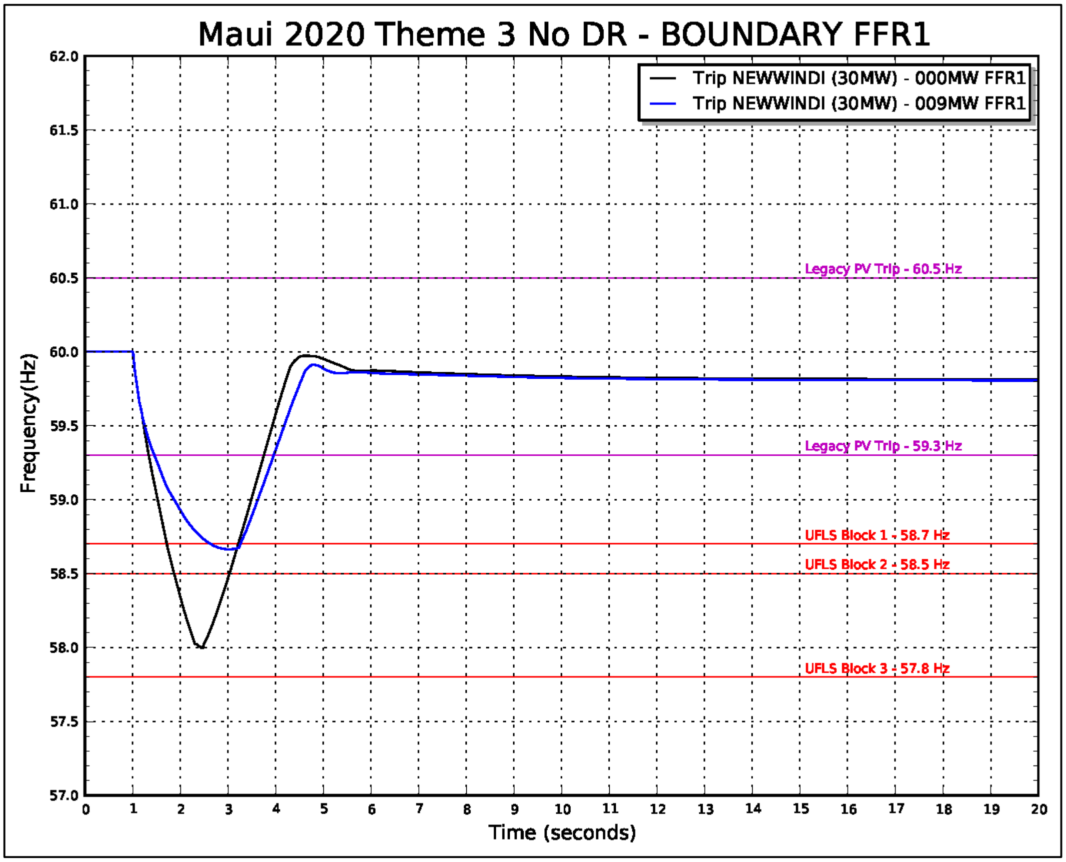

Figure O-216. Frequency Response Profile for FFR1 Boundary Hour

Figure O-216 shows the frequency response profile for a Windfarm trip at 30 MW for a boundary hour. System kinetic energy is 316 MW-sec. With no FFR, the frequency nadir is 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

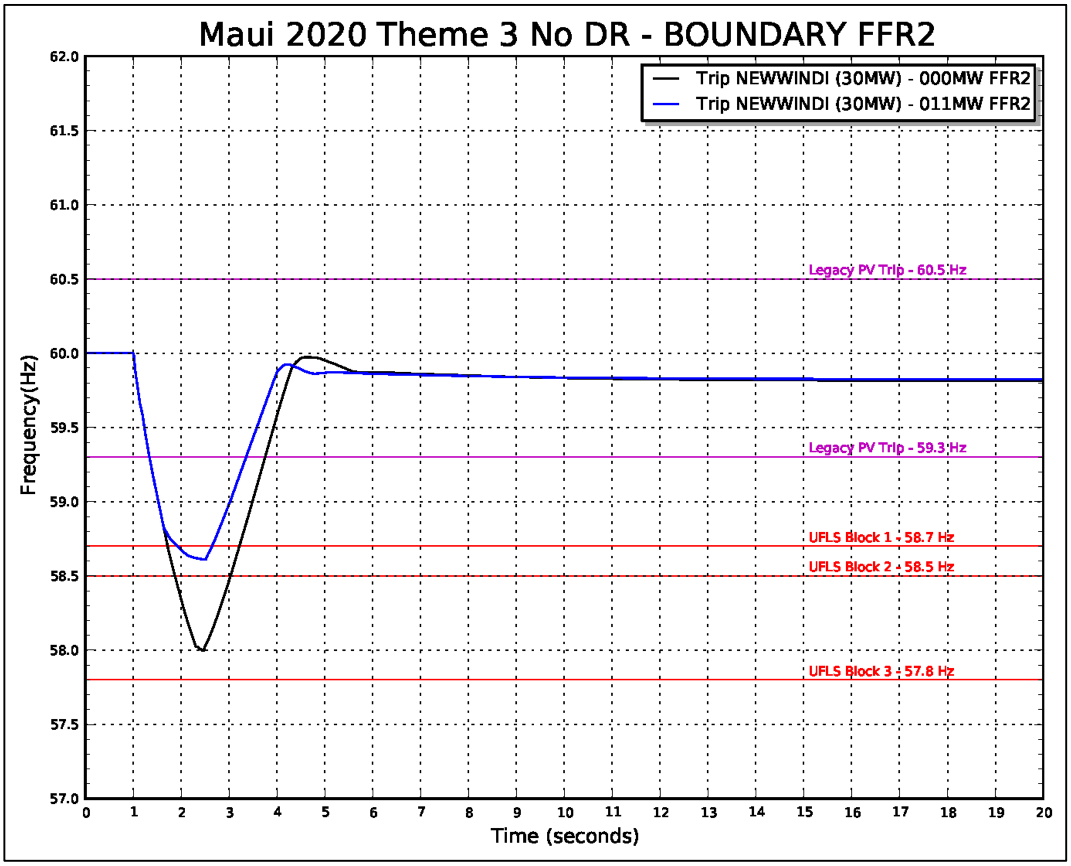

Figure O-217. Frequency Response Profile for FFR2 Boundary Hour

Figure O-217 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 11 MW.

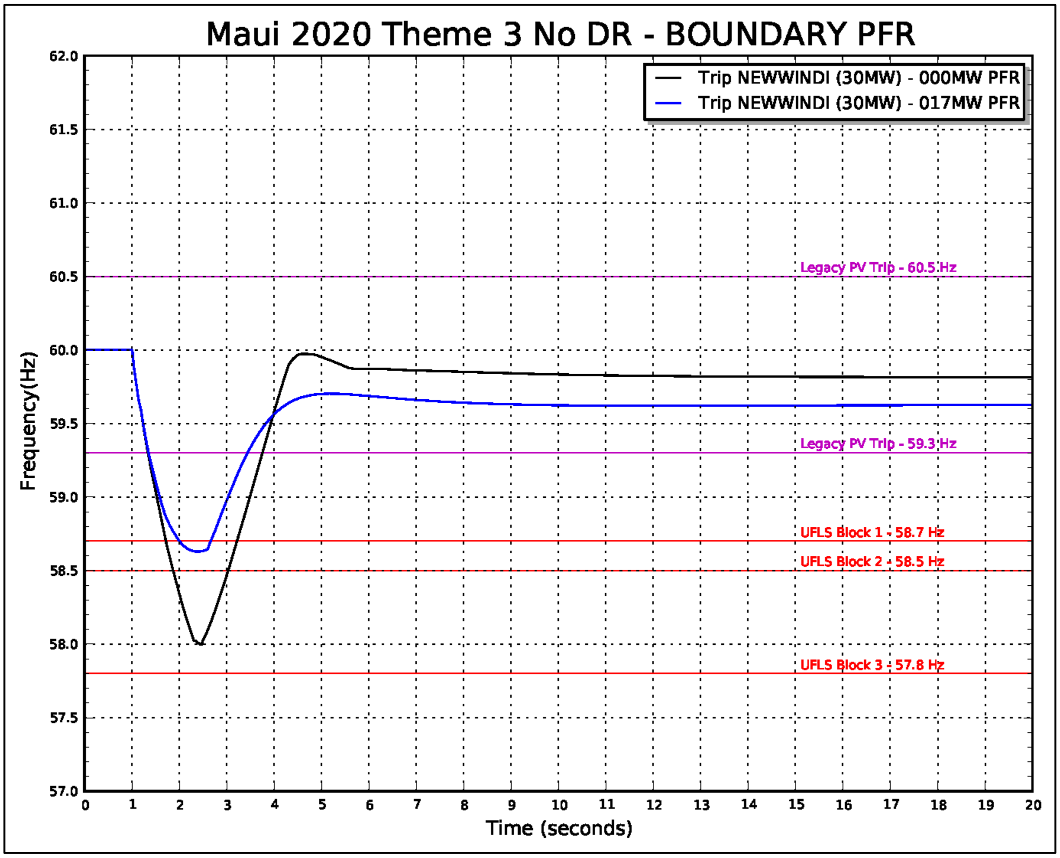

Figure O-218. Frequency Response Profile for PFR Boundary Hour

Figure O-218 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 17 MW. This is in addition to the 40 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					Theme 3 - Fault Sat 5/9/2020 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	15.7	4.3	9.8
Maalaea 15	13.0	3.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54	12.3	7.2	6.4
Maalaea 18	12.8	3.0	2.46	18.5	46	4.3	8.5	1.3
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Total Wind	162					13		
-KWP	30	0						
-Auwahi	21	0				13		
-KWPII	21	0						
-New Wind 1	30	0						
-New Wind 2	30	0						
-New Wind 3	30	0						
Total Utility PV	80					3		
-Utility PV1	20	0				3		
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	125	0				103		
DER Grid Ex	4	0				4		
Total System MVA						72		
Total Kinetic Energy						262		
Total Load						164		
Total Thermal Generation						42		
Total Renewable Generation						123		
Total Generation						165		
Excess Generation						1		
Regulation Requirement						0		
Total Up Regulation						20		
Total Down Regulation						17		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.9
	60.5Hz Capacity			69.5		60.5Hz Output		57.3

Table O-90. Unit Commitment and Dispatch Fault Analysis 2020

Table O-90 shows the unit commitment and dispatch for the 69 kV fault analysis. Inverter-based generation is 103 MW.

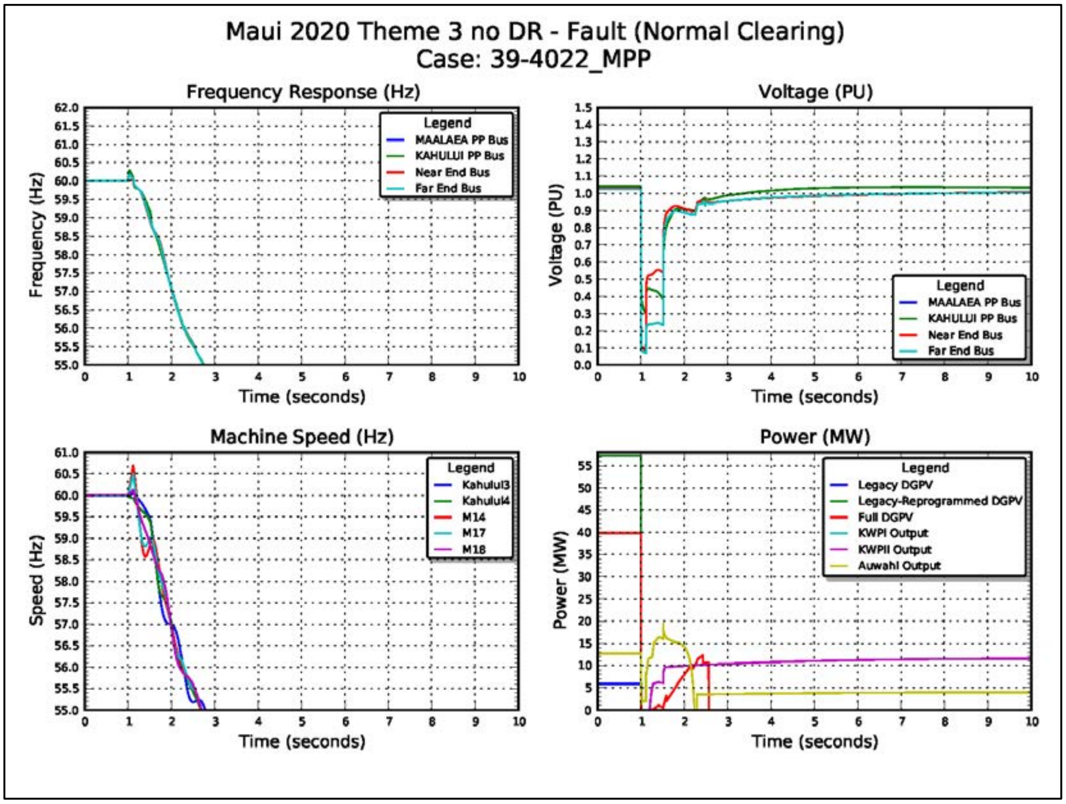

Figure O-219. System Performance Normally Cleared Fault

Figure O-219 shows the system performance for a normally cleared fault at the Ma‘alaea end of the Ma‘alaea-Pu‘unene circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 103 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

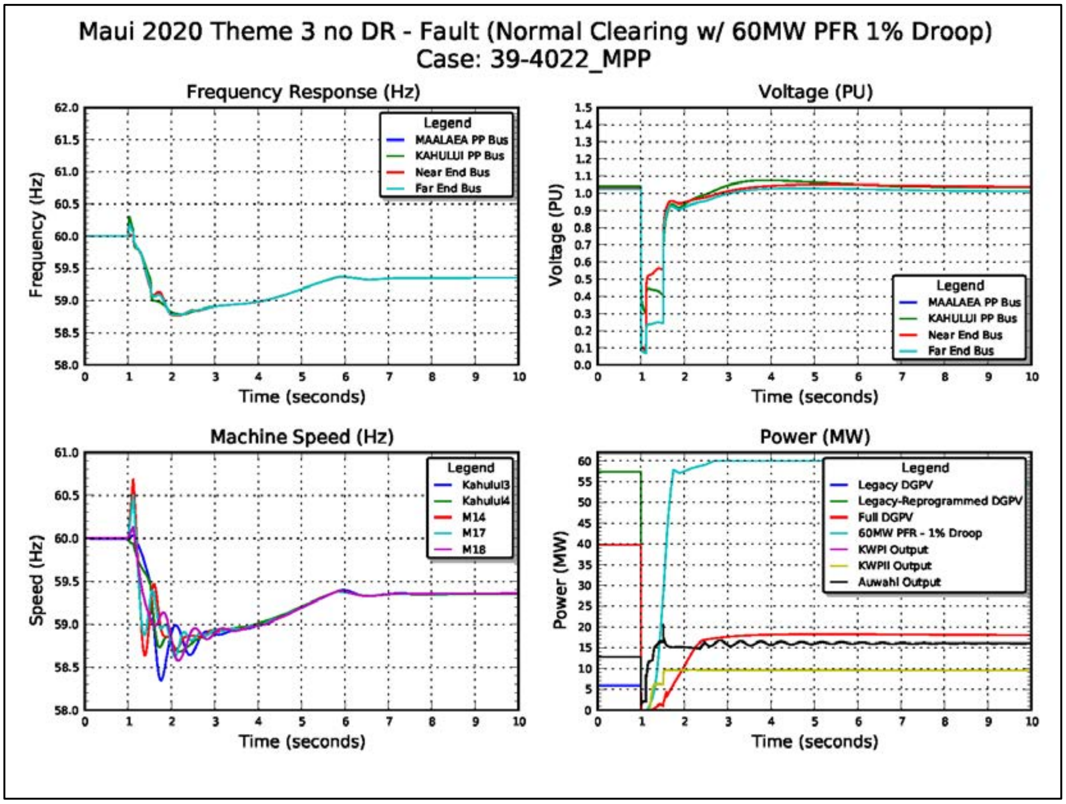

Figure O-220. Normally Cleared Fault Sensitivity 60 MW PFR

Figure O-220 shows system performance with the addition of the 60 MW of PFR at 1% droop response. For the purpose of this analysis, a 60 MW BESS was located at Ma'alaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 60 MW BESS. The aggregate response from synchronous units, the BESS resources, restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2020 Theme 3 No DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 60 MW PFR	Mitigation: 5-Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Unstable	Stable	Stable
	Kanaha	Unstable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Stable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-91. Summary of Results Fault Analysis 2020

Table O-91 shows the results of the 69 kV fault analysis with 60 MW of PFR. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay

schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Fri 10/29/2021 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	4.5	7.0	1.5
Kahului 4	11.5	3.0	3.48	15.6	54	4.5	7.0	1.5
Maalaea 14	20.0	5.9	2.02	28.8	58	7.5	12.5	1.6
Maalaea 15	13.0	4.0	2.46	18.5	46	4.9	8.1	0.9
Maalaea 16	20.0	5.9	2.02	26.8	54	7.5	12.5	1.6
Maalaea 17	19.5	5.9	2.02	26.8	54	13.8	5.7	7.9
Maalaea 18	12.8	3.0	2.46	18.5	46	4.8	8.0	1.8
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.0	3.28	15.6	51	7.1	5.2	0.1
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16	2.3	2.7	2.3
Kahului 2	5.0	0.0	2.62	6.3	16			
Total Wind	162					148		
-KWP	30	0				30		
-Auwahi	21	0				21		
-KWPII	21	0				21		
-New Wind 1	30	0				25		
-New Wind 2	30	0				25		
-New Wind 3	30	0				25		
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	128	0						
DER Grid Ex	8	0						
Total System MVA							170	
Total Kinetic Energy							468	
Total Load							188	
Total Thermal Generation							57	
Total Renewable Generation							148	
Total Generation							205	
Excess Generation							17	
Regulation Requirement							0	
Total Up Regulation							52	
Total Down Regulation							14	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		0.0
		60.5Hz Capacity		69.5		60.5Hz Output		0.0

Table O-92. Unit Commitment and Dispatch 2021 QV Analysis

Table O-92 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Fri 10/29/2021 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	0.0	7.1	0.0
Kahului 4	9.4	0.0	0.0	9.4	0.0
Maalaea 14	4.1	0.0	3.8	0.3	3.8
Maalaea 15	2.9	0.0	0.8	2.1	0.8
Maalaea 16	4.1	0.0	3.8	0.3	3.8
Maalaea 17	15.0	0.0	7.6	7.4	7.6
Maalaea 18	12.0	0.0	3.8	8.2	3.8
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0	0.1	9.3	0.1
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0.0			
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	0.0	14.5	0.2
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0	0.8	9.0	0.8
-New Wind 2	9.9	0.0	0.8	9.0	0.8
-New Wind 3	9.9	0.0	0.8	9.0	0.8
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			19.9		
Total Renewable MVAR Generation			2.5		
Total Cap Bank MVAR			53.9		
Charging MVAR			6.1		
Total MVAR Supply			82.4		
Total MVAR Load			32.3		
Total MVAR Losses			50.0		
Excess MVAR Generation			0.1		
Total MVAR Supply Capability				102	
Total MVAR Absorb Capability					19.9

Table O-93. MVAR Capability 2021 QV Analysis

Table O-93 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	MPP-Kihei 69 kV
104	MPP-Waiinu 69 kV
113	Wailea-Auwahi Tap 69 kV

Table O-94. N-1 Contingencies 2021 QV Analysis

Table O-94 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

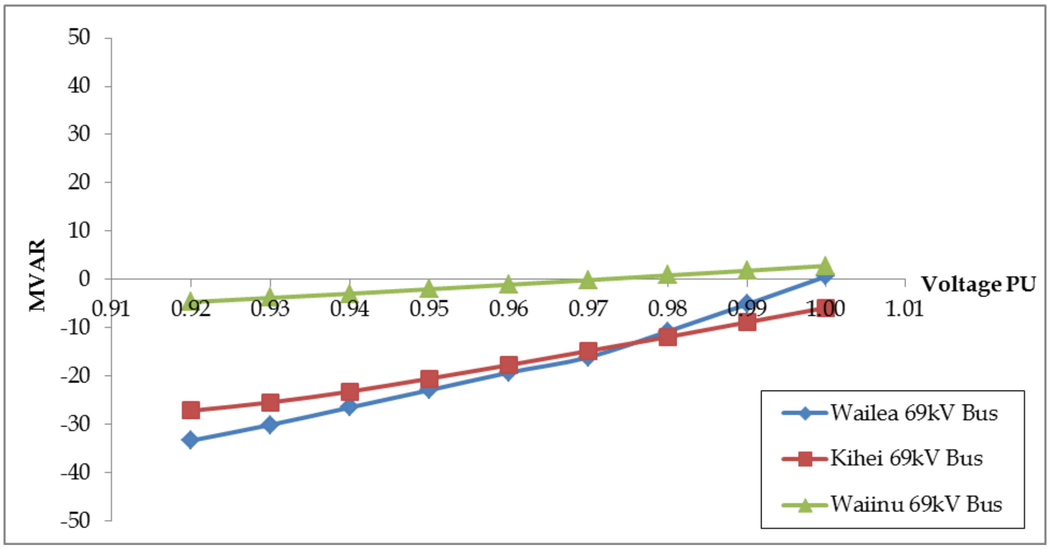

Figure O-221. QV Curves 2021

Figure O-221 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	113	1	113	-5	113	-11	113	-16	113	-19	113	-23	113	-27	113	-30	113	-33
35	Kihei 69 kV Bus	102	-6	102	-9	102	-12	102	-15	102	-18	102	-21	102	-23	102	-25	102	-27
636	Waiinu 69 kV Bus	104	3	104	2	104	1	104	0	104	-1	104	-2	104	-3	104	-4	104	-5

Table O-95. Summary of Results 2021 QV Analysis

Table O-95 shows the results of the QV analysis for 2021. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

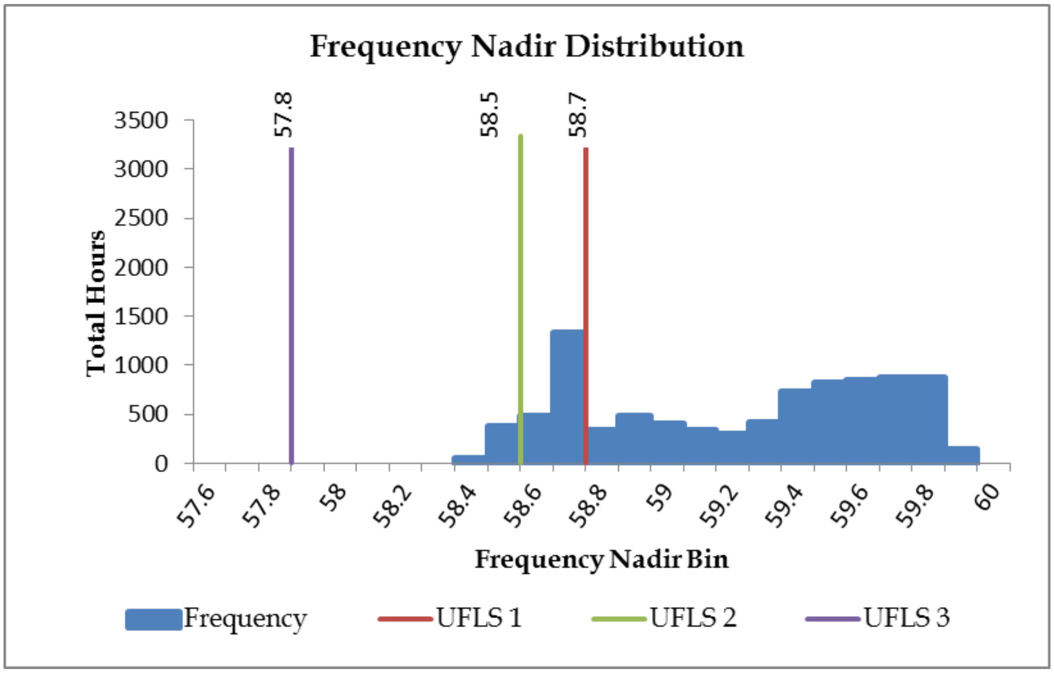

Figure O-222. Frequency Nadir Histogram for 2021

Figure O-222 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 374 hours was 12:00 PM on Monday, May 10. The frequency nadir range for the typical hour is 58.5 - 58.6 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 53 hours was 4:00 PM on Saturday, March 13. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

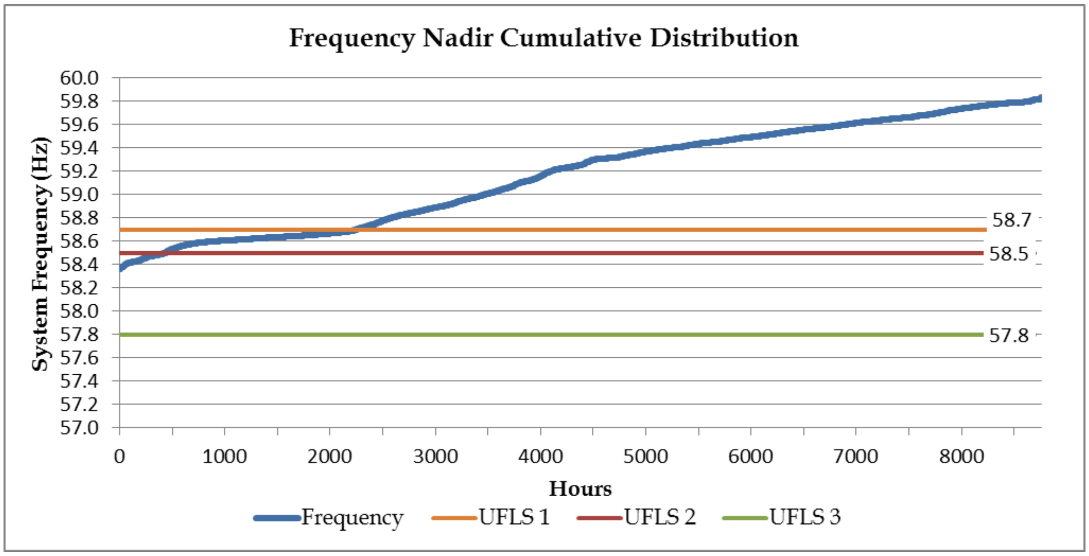

Figure O-223. Frequency Nadir Duration Curve 2021

Figure O-223 shows the frequency nadir duration curve for the Theme 3 resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 427 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Mon 05/10/2021 Hour 12			Theme 3 - KWP I Trip Boundary Sat 3/13/2021 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0			
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	12.0	8.0	6.1	14.0	6.0	8.1
Maalaea 15	13.0	4.0	2.46	18.5	46	4.0	9.0	0.0	4.0	9.0	0.0
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	162					48			60		
-KWP	30	0				27			30		
-Auwahi	21	0									
-KWPII	21	0				21					
-New Wind 1	30	0							30		
-New Wind 2	30	0									
-New Wind 3	30	0									
Total Utility PV	80					2			0		
-Utility PV1	20	0				2					
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	128	0				103			79		
DER Grid Ex	8	0				6			4		
Total System MVA							74			61	
Total Kinetic Energy							351			262	
Total Load							184			170	
Total Thermal Generation							26			23	
Total Renewable Generation							159			143	
Total Generation							185			166	
Excess Generation							1			-4	
Regulation Requirement							0			0	
Total Up Regulation							30			22	
Total Down Regulation							6			8	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.8	59.3Hz Output		4.4
	60.5Hz Capacity			69.5		60.5Hz Output		55.8	60.5Hz Output		42.8

Table O-96. Unit Commitment and Dispatch 2021

Table O-96 shows the unit commitment and dispatch for the typical hour (5/10/21, 12:00 PM) and boundary hour (3/13/21, 4:00 PM).

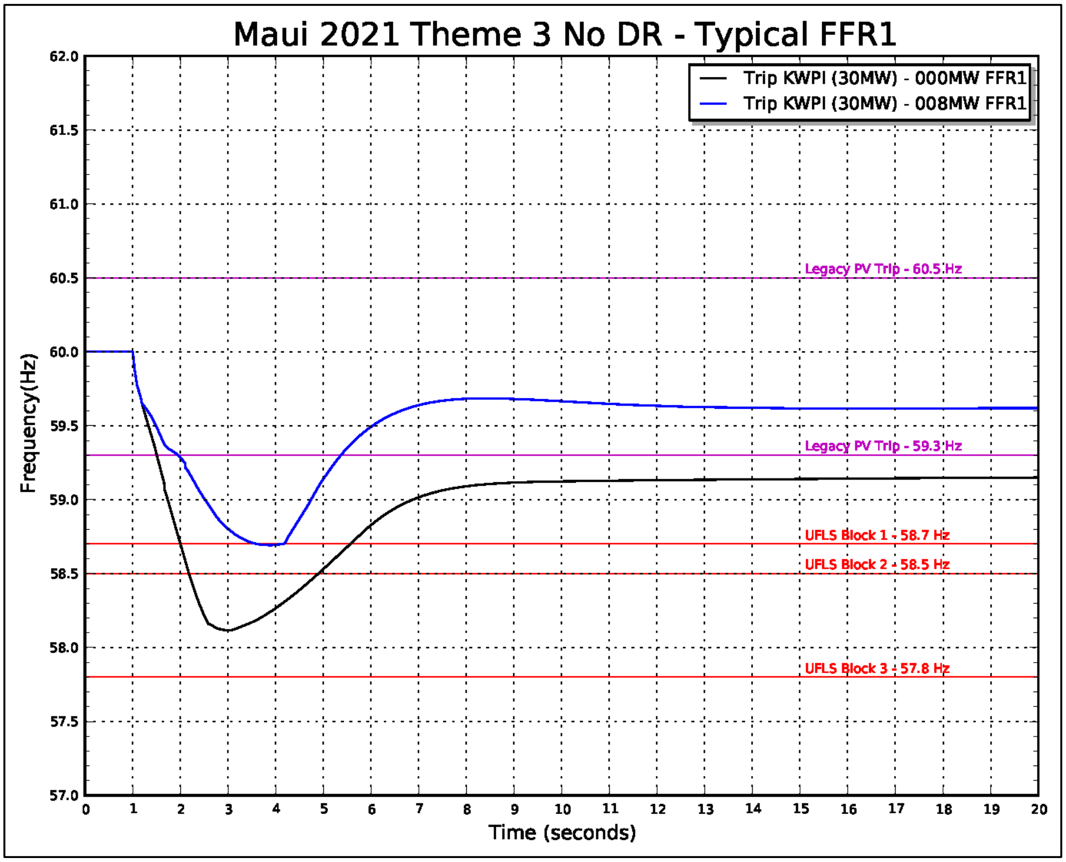

Figure O-224. Frequency Response Profile for FFR1 Typical Hour

Figure O-224 shows the frequency response profile for a KWP 1 trip at 30 MW for a typical hour. System kinetic energy is 351 MW-sec and the capacity of legacy PV that will disconnect from the system is 5.8 MW. With no FFR, the frequency nadir is 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

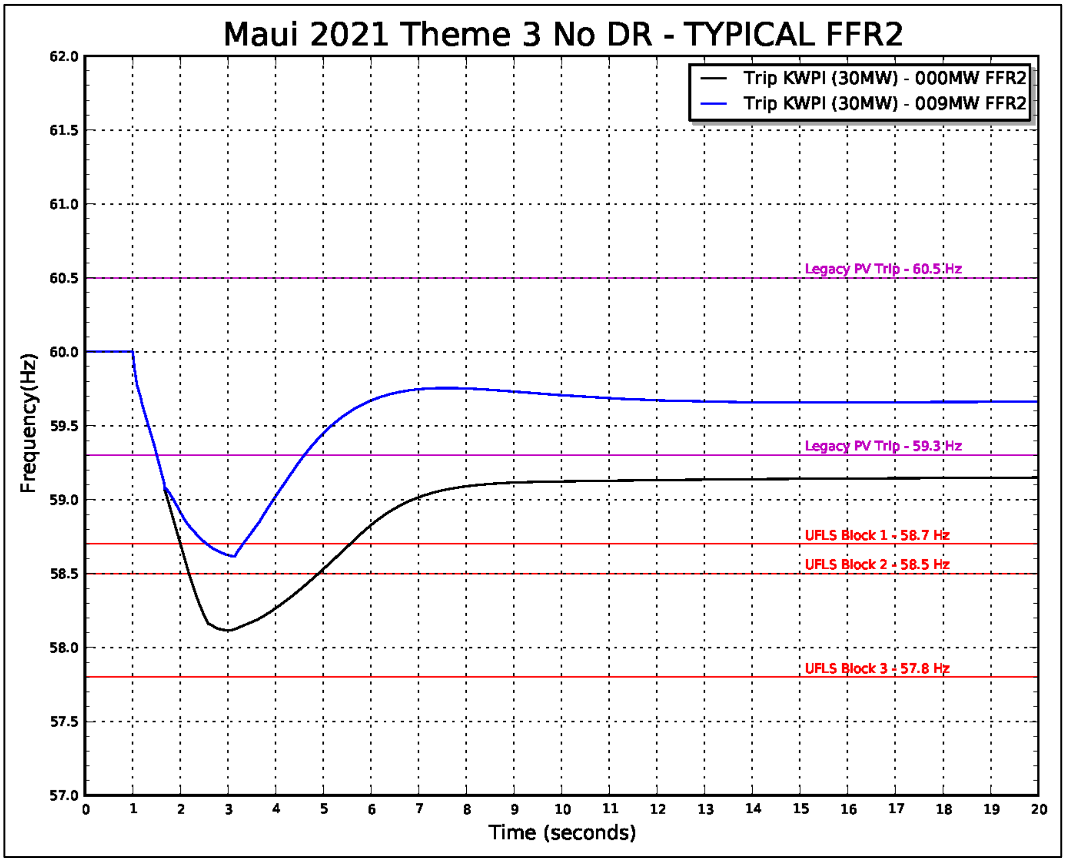

Figure O-225. Frequency Response Profile for FFR2 Typical Hour

Figure O-225 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 9 MW.

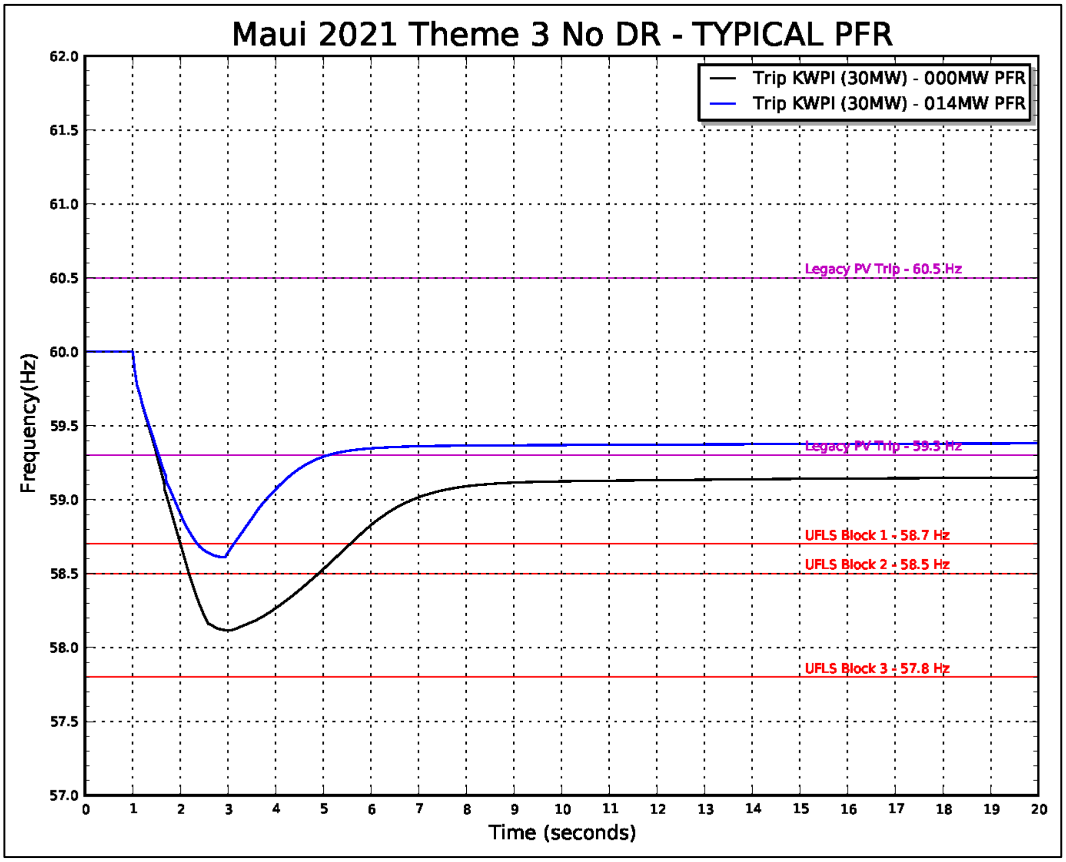

Figure O-226. Frequency Response Profile for PFR Typical Hour

Figure O-226 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

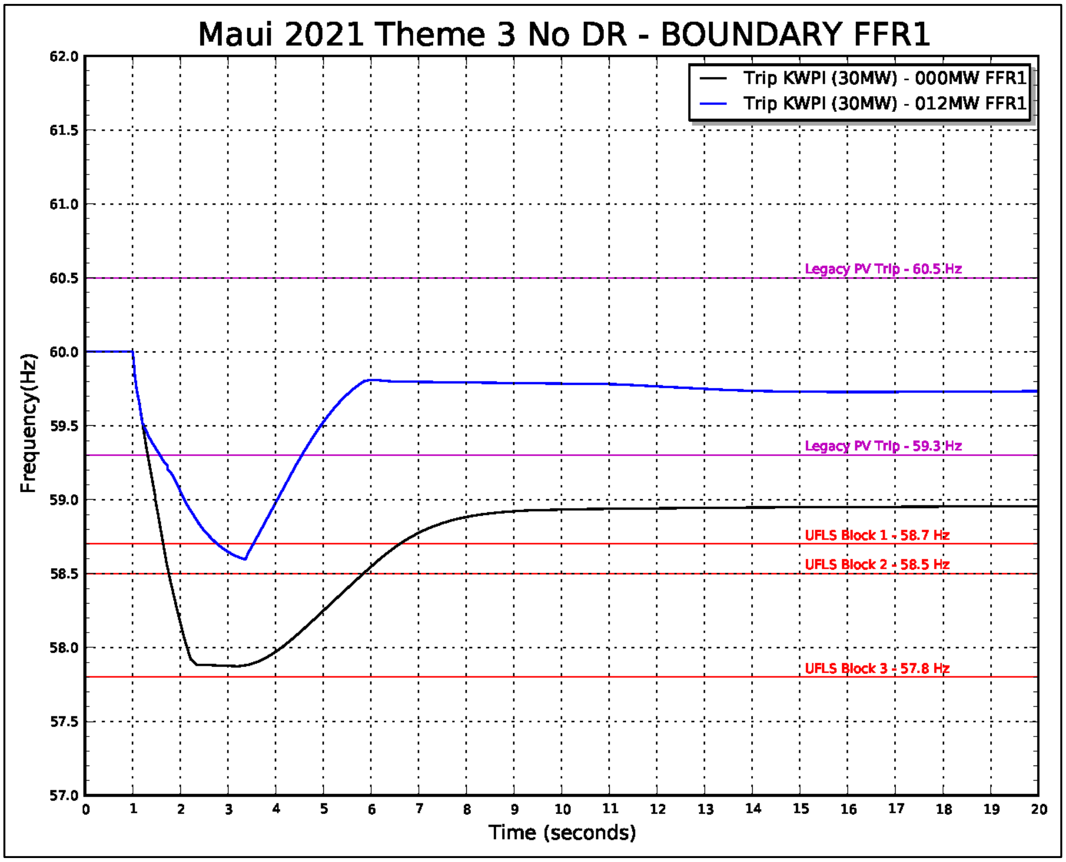

Figure O-227. Frequency Response Profile for FFR1 Boundary Hour

Figure O-227 shows the frequency response profile for a KWP 1 trip at 30 MW for a boundary hour. System kinetic energy is 262 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.4 MW. With no FFR, the frequency nadir breaches 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 12 MW.

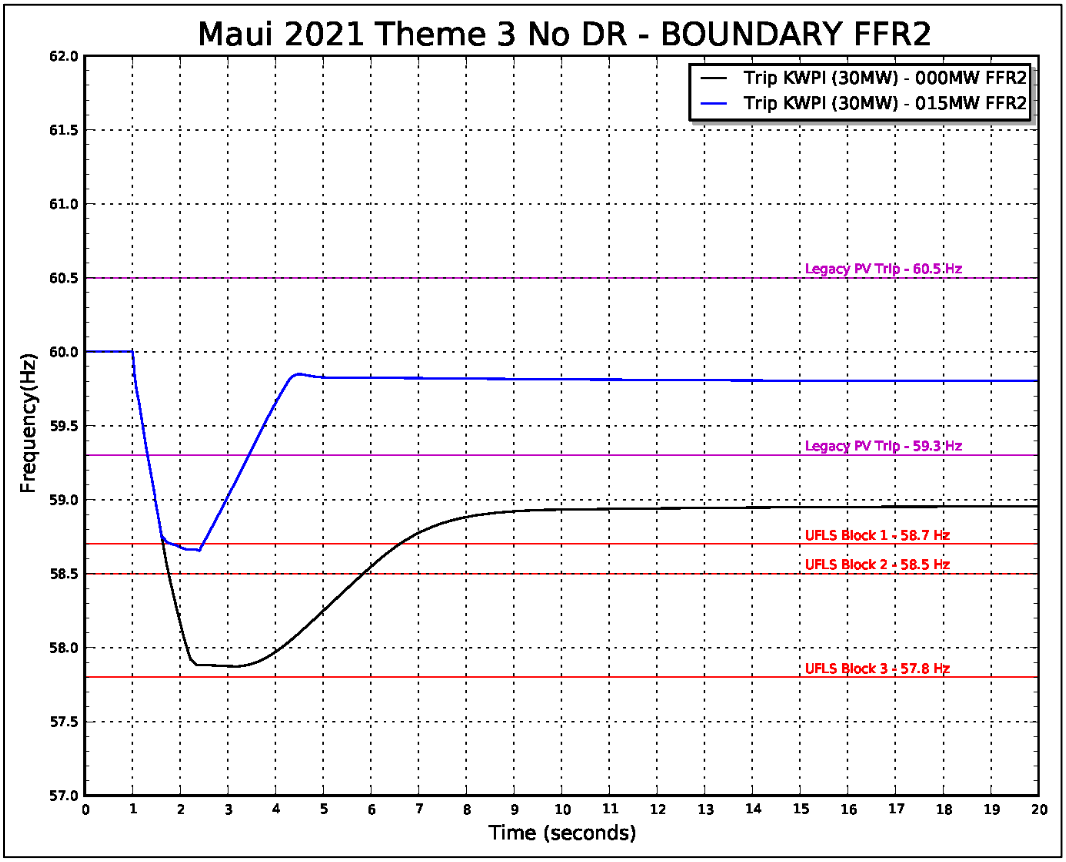

Figure O-228. Frequency Response Profile for FFR2 Boundary Hour

Figure O-228 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 15 MW.

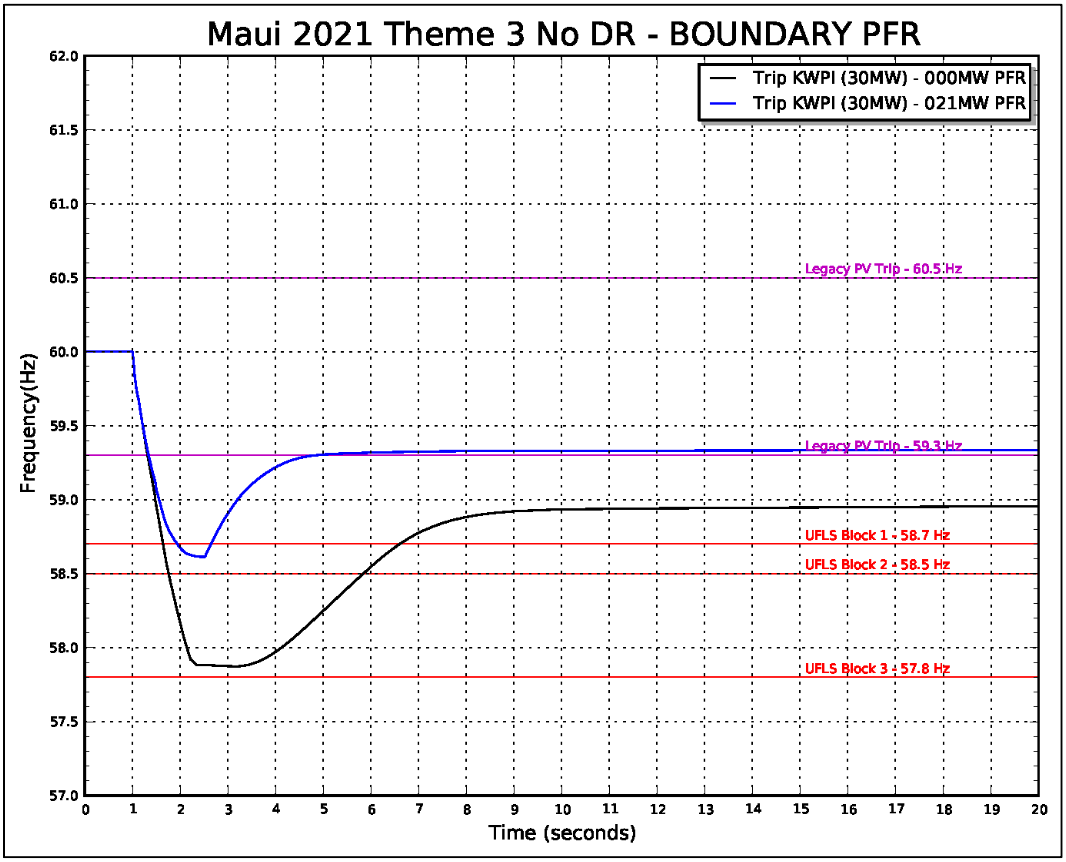

Figure O-229. Frequency Response Profile for PFR Boundary Hour

Figure O-229 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 21 MW. This is in addition to the 22 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults and delayed clearing faults (breaker failure) on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					Theme 3 - Fault Mon 4/5/2021 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	5.0	6.5	2.0
Kahului 4	11.5	3.0	3.48	15.6	54	5.0	6.5	2.0
Maalaea 14	20.0	5.9	2.02	26.8	58	12.0	8.0	6.1
Maalaea 15	13.0	4.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 2	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Total Wind	162					56		
-KWP	30	0				30		
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0				5		
-New Wind 2	30	0						
-New Wind 3	30	0						
Total Utility PV	80					5		
-Utility PV1	20	0				5		
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	128	0				102		
DER Grid Ex	8	0				4		
Total System MVA						29		
Total Kinetic Energy						305		
Total Load						188		
Total Thermal Generation						22		
Total Renewable Generation						167		
Total Generation						189		
Excess Generation						1		
Regulation Requirement						0		
Total Up Regulation						8		
Total Down Regulation						6		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.7
	60.5Hz Capacity			69.5		60.5Hz Output		55.2

Table O-97. Unit Commitment and Dispatch Fault Analysis 2021

Table O-97 shows the unit commitment and dispatch for the 69 kV fault analysis (4/5/21, 1:00 PM). The capacity from inverter-based generation is 102 MW.

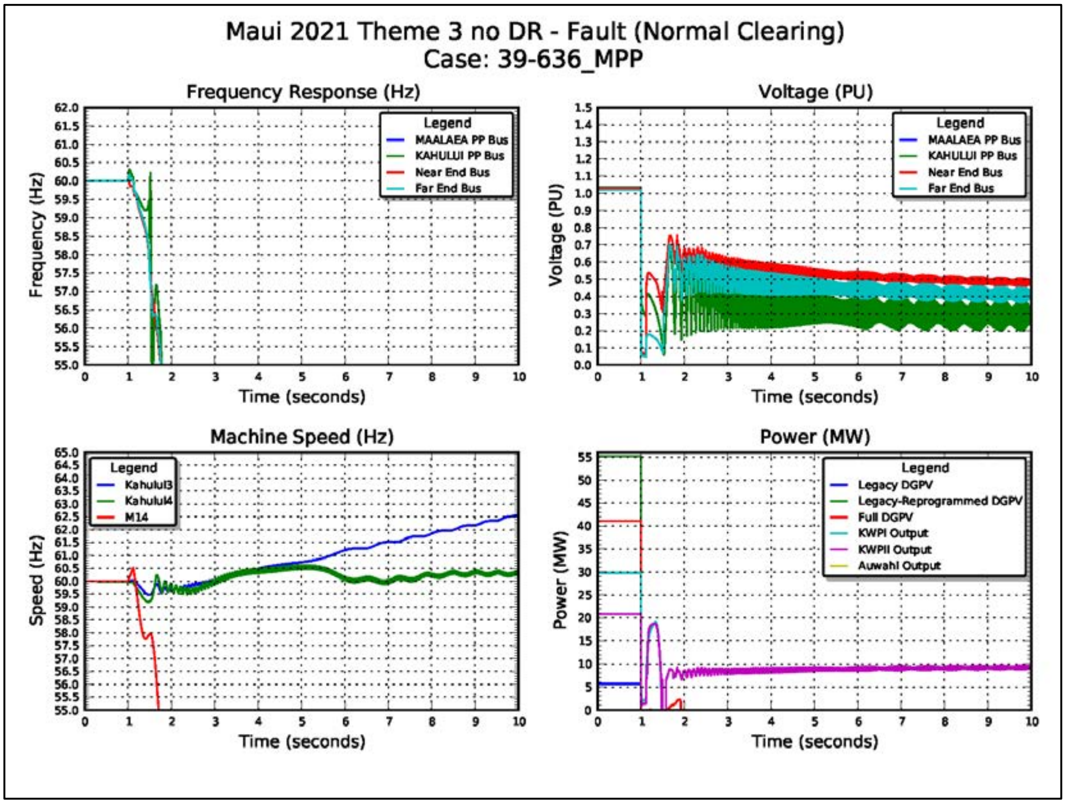

Figure O-230. System Performance Normally Cleared Fault

Figure O-230 shows the system performance for a normally cleared fault at the Ma‘alaea end of the Ma‘alaea-Waiinu circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 102 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and causing the system to collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

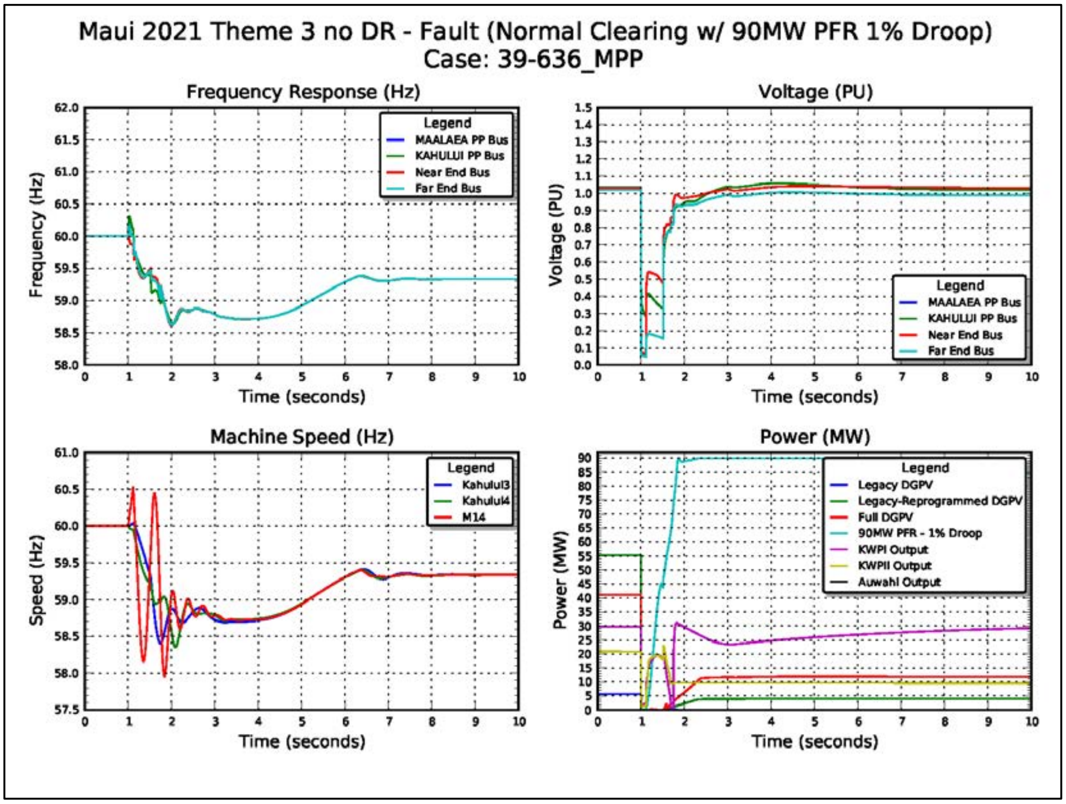

Figure O-231. Normally Cleared Fault Sensitivity 60 MW PFR

Figure O-231 shows system performance with the addition of the 90 MW of PFR at 1% droop response. For the purpose of this analysis, a 90 MW BESS was located at Maʻalaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 90 MW BESS. The aggregate response from synchronous units, the BESS resources, restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2021 Theme 3 No DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 90 MW PFR	Mitigation: 5-Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Unstable	Stable	Stable
	Kanaha	Unstable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Unstable	Stable	Stable
	Waiinu	Unstable	Stable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Stable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Unstable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-98. Summary of Results Fault Analysis 2021

Table O-98 shows the results of the 69 kV fault analysis with 90 MW of PFR. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay

schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

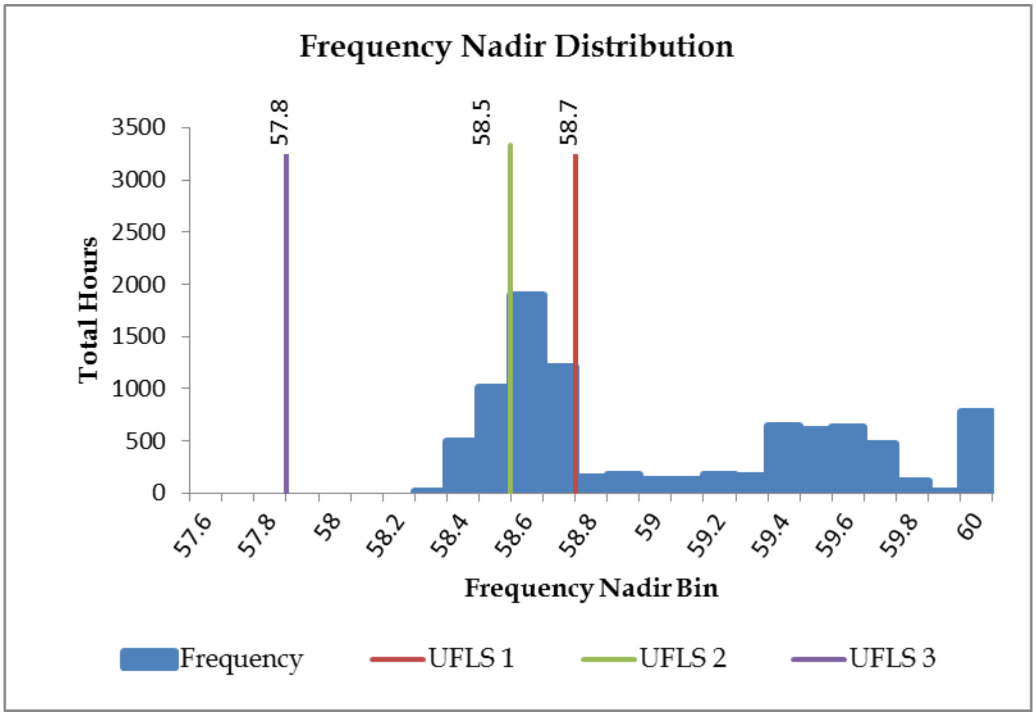

Figure O-232. Frequency Nadir Histogram for 2023

Figure O-232 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 1009 hours was 3:00 PM on Monday, May 15. The frequency nadir range for the typical hour is 58.5 - 58.6 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 2 hours was 4:00 AM on Thursday, November 2. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires two blocks of UFLS to stabilize system frequency.

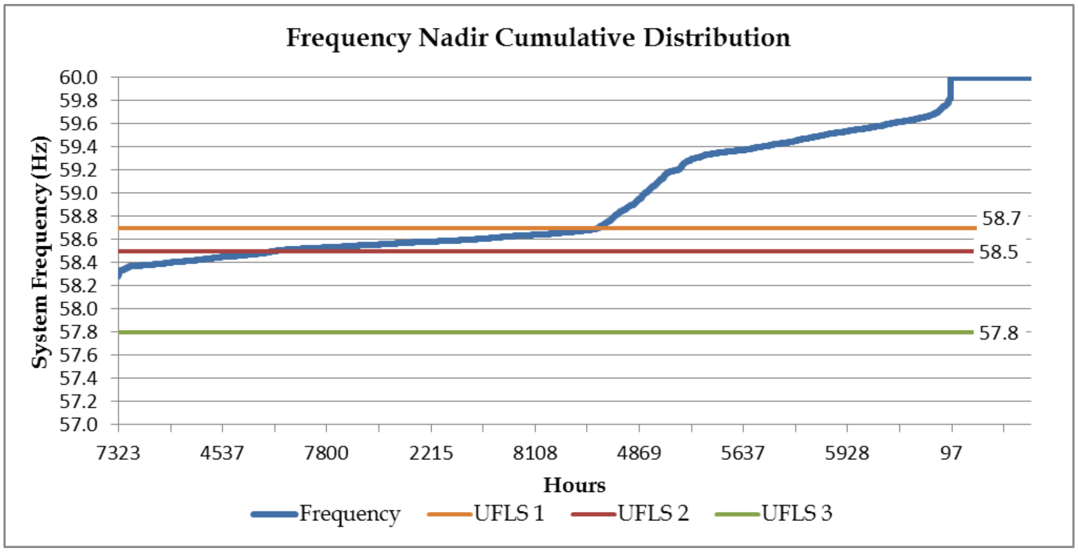

Figure O-233. Frequency Nadir Duration Curve 2023

Figure O-233 shows the frequency nadir duration curve for the Theme 3 resource plan in 2023. The system is at risk of exceeding the UFLS requirements of TPL-001 for 497 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Typical Mon 5/15/2023 Hour 15			Theme 3 - KWP I Trip Boundary Thu 11/2/2023 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87	8.0	12.0	2.0	7.0	13.0	1.0
Maalaea 14	20.0	5.9	2.02	26.8	54						
Maalaea 15	13.0	5.0	2.46	18.5	46						
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16		*Synchronous Condenser*			*Synchronous Condenser*	
Kahului 2	5.0	0.0	2.62	6.3	16		*Synchronous Condenser*			*Synchronous Condenser*	
Kahului 3	11.5	3.0	3.27	13.5	44		*Synchronous Condenser*			*Synchronous Condenser*	
Kahului 4	11.5	3.0	1.74	15.6	27		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Total Wind	162					88			97		
-KWP	30	0				25			30		
-Auwahi	21	0				6					
-KWPII	21	0				21			19		
-New Wind 1	30	0				30			24		
-New Wind 2	30	0				6			24		
-New Wind 3	30	0									
Total Utility PV	80					5					
-Utility PV1	20	0				5					
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	131	0				77					
DER Grid Ex	10	0				5					
Total System MVA							127			25	
Total Kinetic Energy							295			295	
Total Load							182			104	
Total Thermal Generation							8			7	
Total Renewable Generation							175			97	
Total Generation							183			104	
Excess Generation							1			0	
Regulation Requirement							0			0	
Total Up Regulation							0			0	
Total Down Regulation							0			0	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		4.2	59.3Hz Output		0.0
		60.5Hz Capacity		69.5		60.5Hz Output		40.8	60.5Hz Output		0.0

Table O-99. Unit Commitment and Dispatch 2023

Table O-99 shows the unit commitment and dispatch for the typical hour (5/15/23, 3:00 PM) and boundary hour (11/2/23, 4:00 AM).

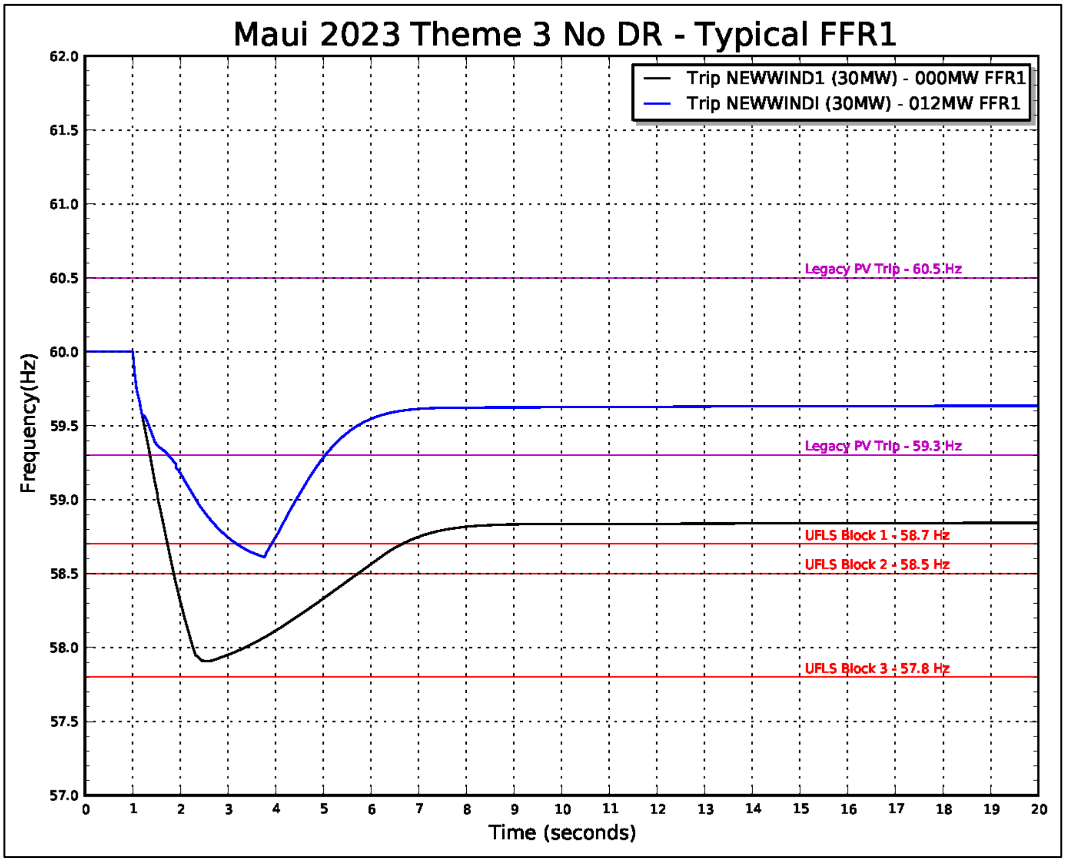

Figure O-234. Frequency Response Profile for FFR1 Typical Hour

Figure O-234 shows the frequency response profile for a windfarm trip at 30 MW for a typical hour. System kinetic energy is 295 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.2 MW. With no FFR, the frequency nadir is 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 12 MW.

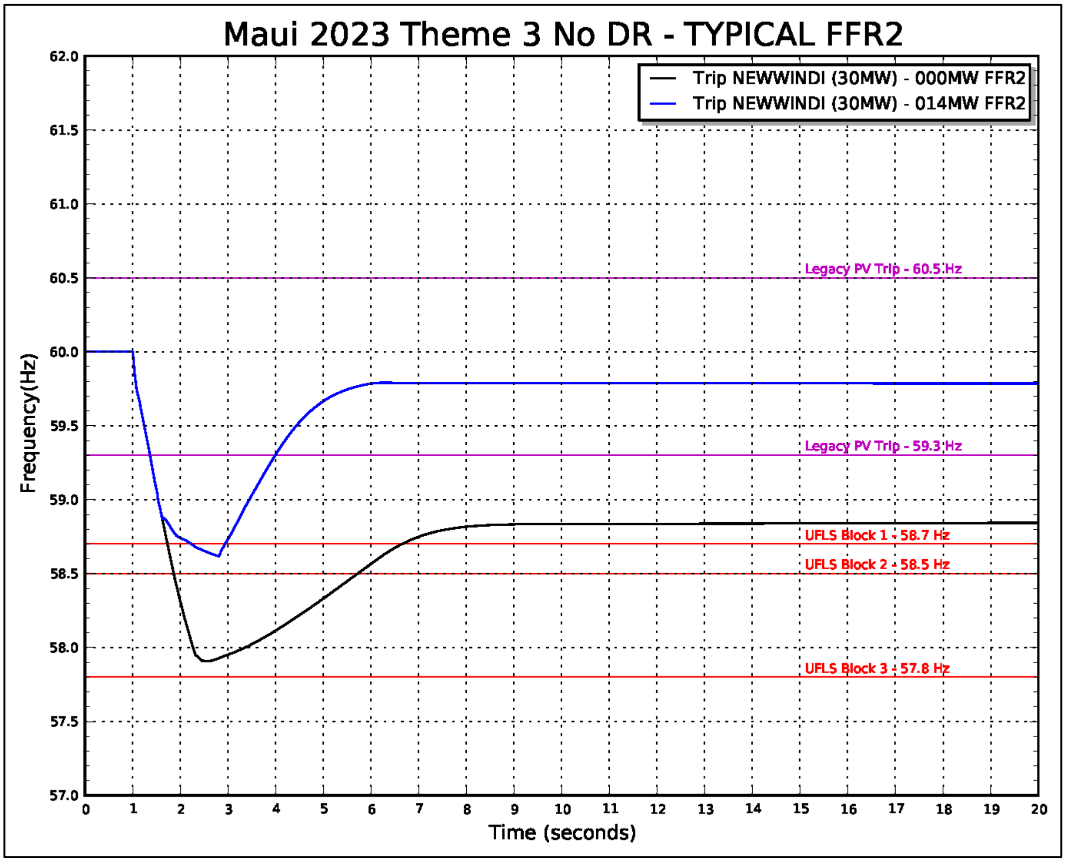

Figure O-235. Frequency Response Profile for FFR2 Typical Hour

Figure O-235 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 14 MW.

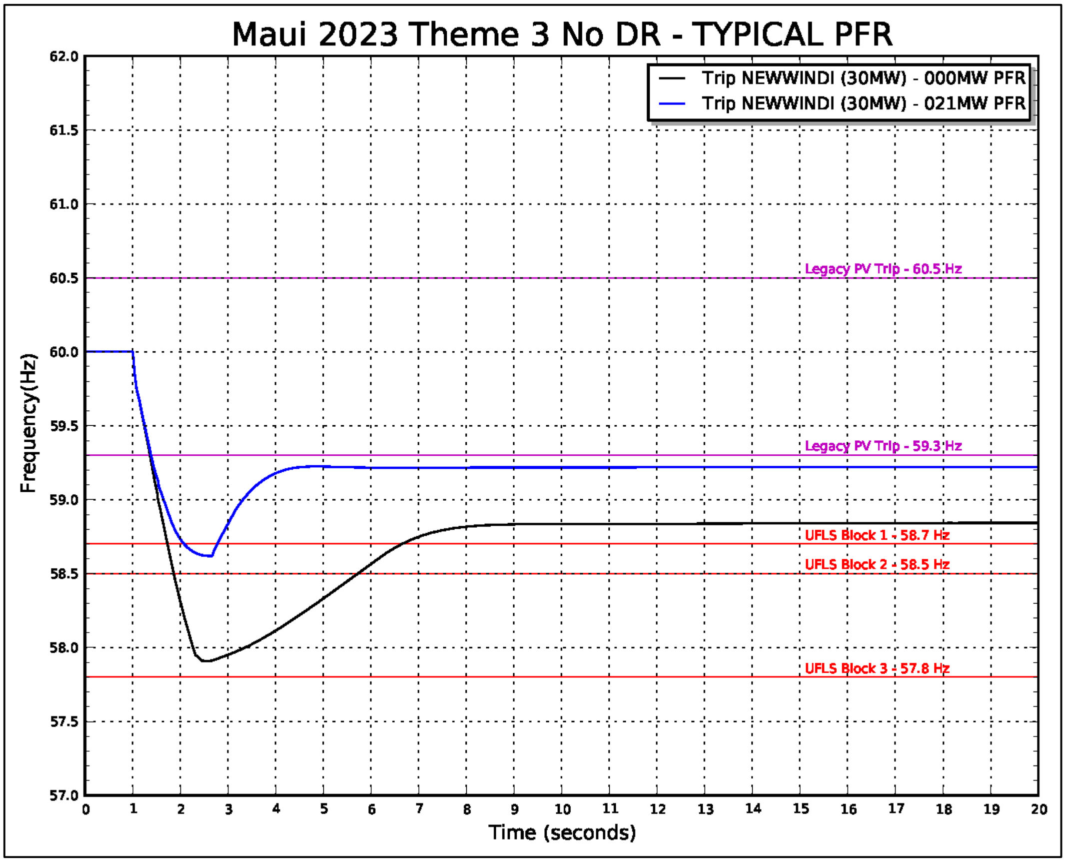

Figure O-236. Frequency Response Profile for PFR Typical Hour

Figure O-236 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 21 MW.

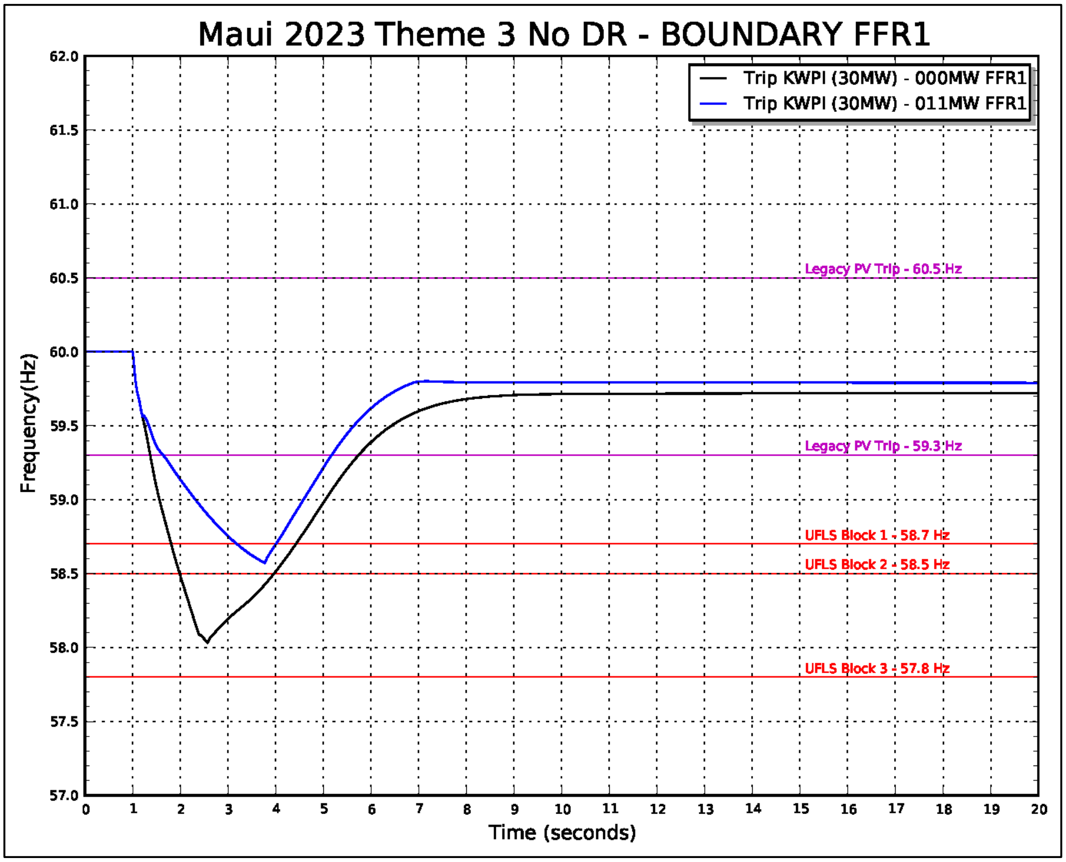

Figure O-237. Frequency Response Profile for FFR1 Boundary Hour

Figure O-237 shows the frequency response profile for a KWP 1 trip at 30 MW for a boundary hour. System kinetic energy is 295 MW-sec. With no FFR, the frequency nadir approaches 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 11 MW.

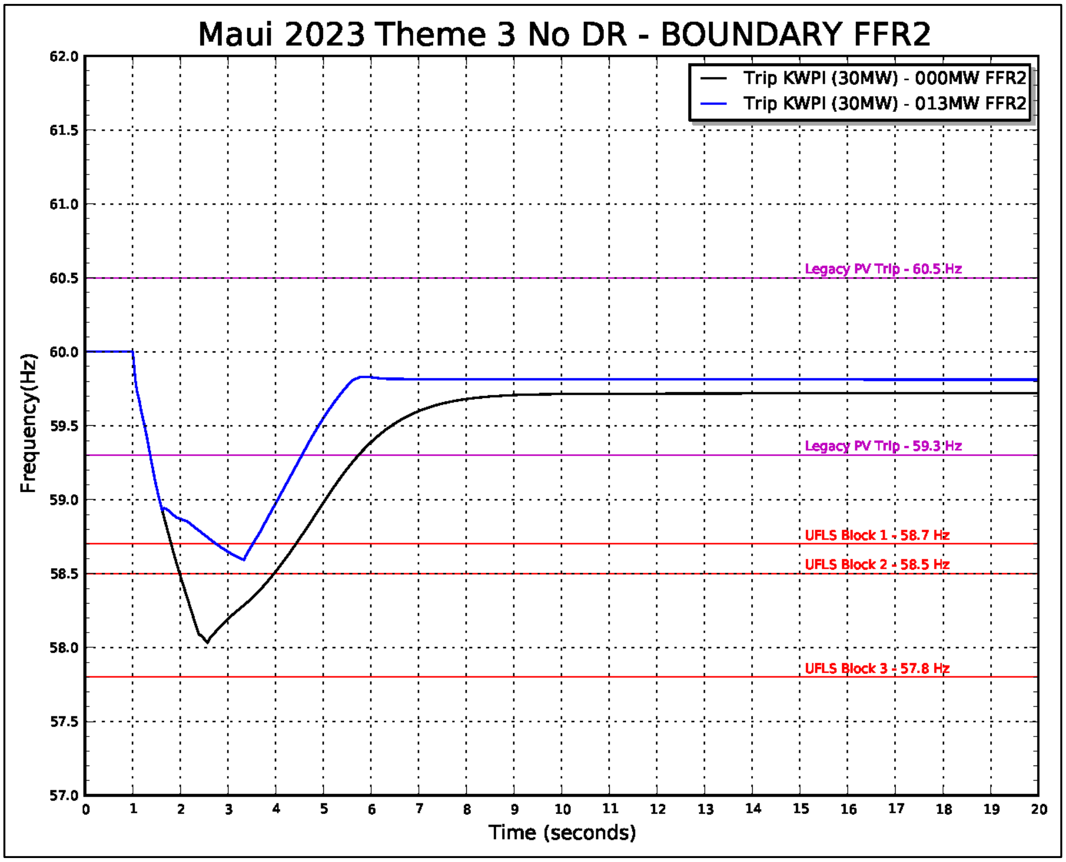

Figure O-238. Frequency Response Profile for FFR2 Boundary Hour

Figure O-238 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 13 MW.

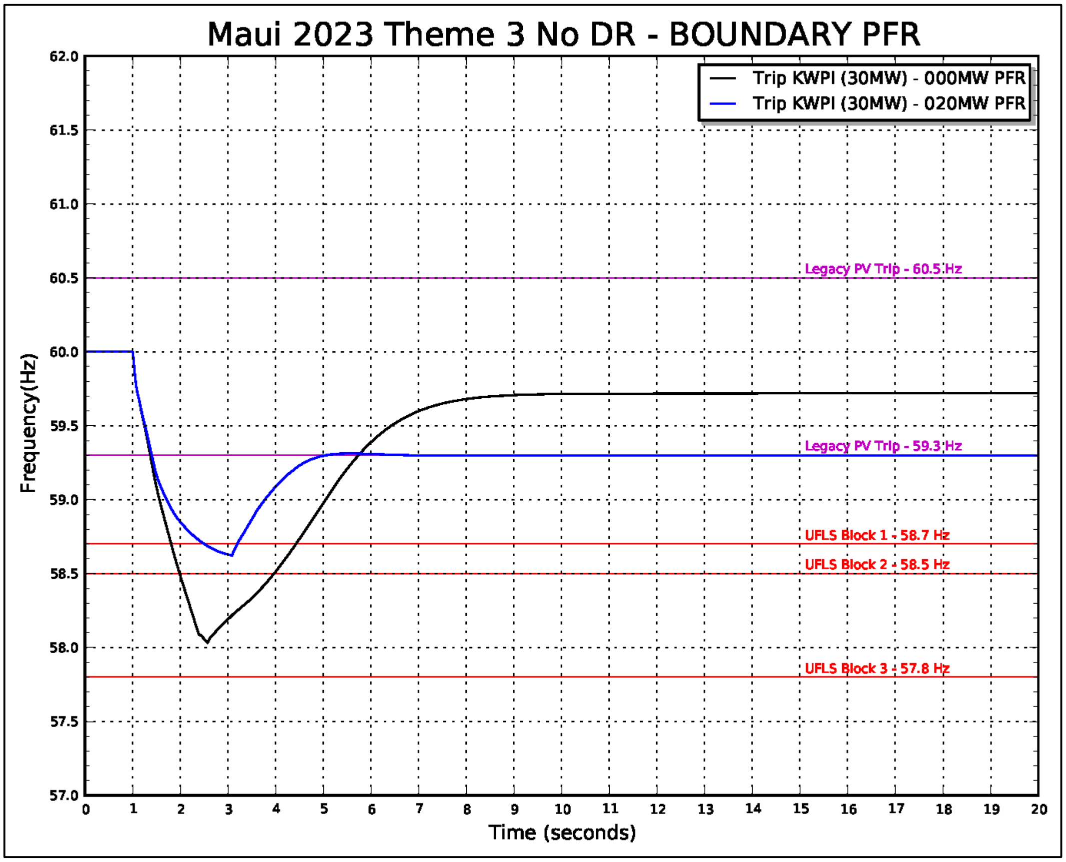

Figure O-239. Frequency Response Profile for PFR Boundary Hour

Figure O-239 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 20 MW.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production simulation data that represents a boundary condition.

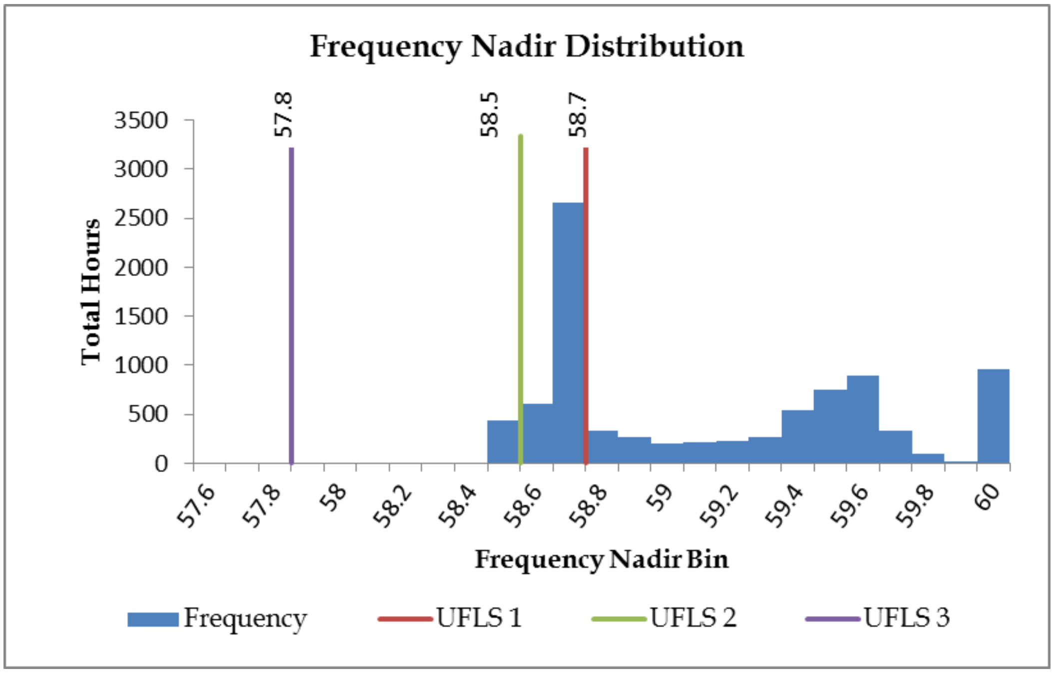

Figure O-240. Frequency Nadir Histogram for 2030

Figure O-240 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. A boundary hour was selected from a maximum distribution of 429 hours was 4:00 AM on Thursday, May 31. The frequency nadir range for the typical hour is 58.3 - 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

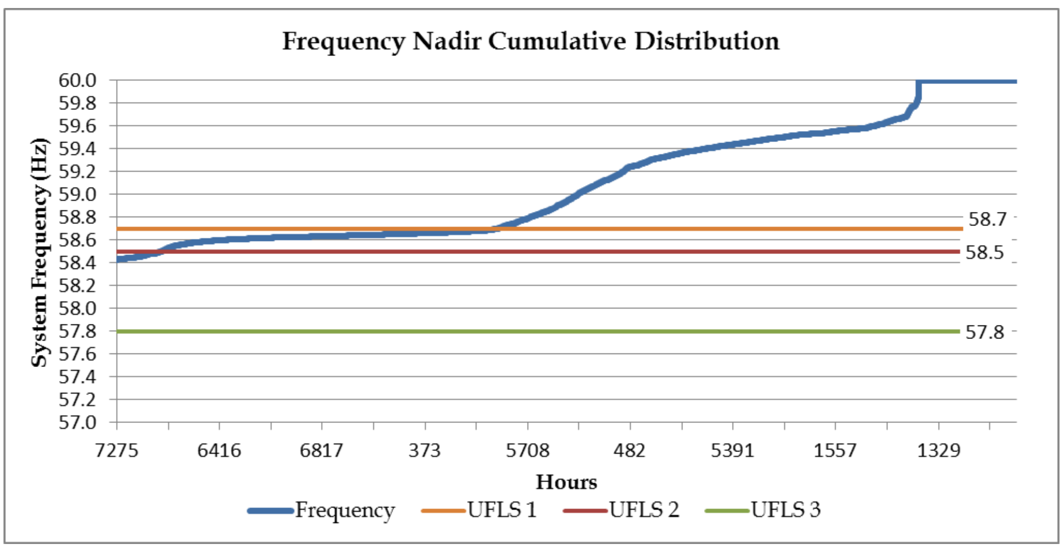

Figure O-241. Frequency Nadir Duration Curve 2030

Figure O-241 shows the frequency nadir duration curve for the Theme 3 resource plan in 2030. The system is at risk of exceeding the UFLS requirements of TPL-001 for 429 hours of the year.

Unit	Unit Ratings					Theme 3 - KWP I Trip Boundary Thu 10/31/2030 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Biomass 1	20.0	7.0	3.48	25.0	87	7.0	13.0	0.0
Geothermal 1	20.0	5.0	3.48	25.0	87	6.0	14.0	1.0
Geothermal 2	20.0	5.0	3.48	25.0	87	5.0	15.0	0.0
Maalaea 14	20.0	5.9	2.02	26.8	58			
Maalaea 15	13.0	5.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
ICE9_1	9.0	4.6	1.00	11.3	11			
ICE9_2	9.0	4.6	1.00	11.3	11			
Kahului 1	0.0	0.0	2.62	6.3	16		*Synchronous Condenser*	
Kahului 2	0.0	0.0	2.62	6.3	16		*Synchronous Condenser*	
Kahului 3	0.0	0.0	3.27	13.5	44		*Synchronous Condenser*	
Kahului 4	0.0	0.0	1.74	15.6	27		*Synchronous Condenser*	
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Total Wind	162					81		
-KWP	30	0				30		
-Auwahi	21	0						
-KWPII	21	0				19		
-New Wind 1	30	0				16		
-New Wind 2	30	0				16		
-New Wind 3	30	0						
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	138.9	0						
DER Grid Ex	16.0	0						
Total System MVA							177	
Total Kinetic Energy							469	
Total Load							99	
Total Thermal Generation							18	
Total Renewable Generation							81	
Total Generation							99	
Excess Generation							0	
Regulation Requirement							0	
Total Up Regulation							0	
Total Down Regulation							0	
Legacy DG-PV	59.3Hz Capacity			6.7		59.3Hz Output		0.0
	60.5Hz Capacity			29.9		60.5Hz Output		0.0

Table O-100. Unit Commitment and Dispatch 2030

Table O-100 shows the unit commitment and dispatch for the boundary hour (10/31/2030, 4:00AM).

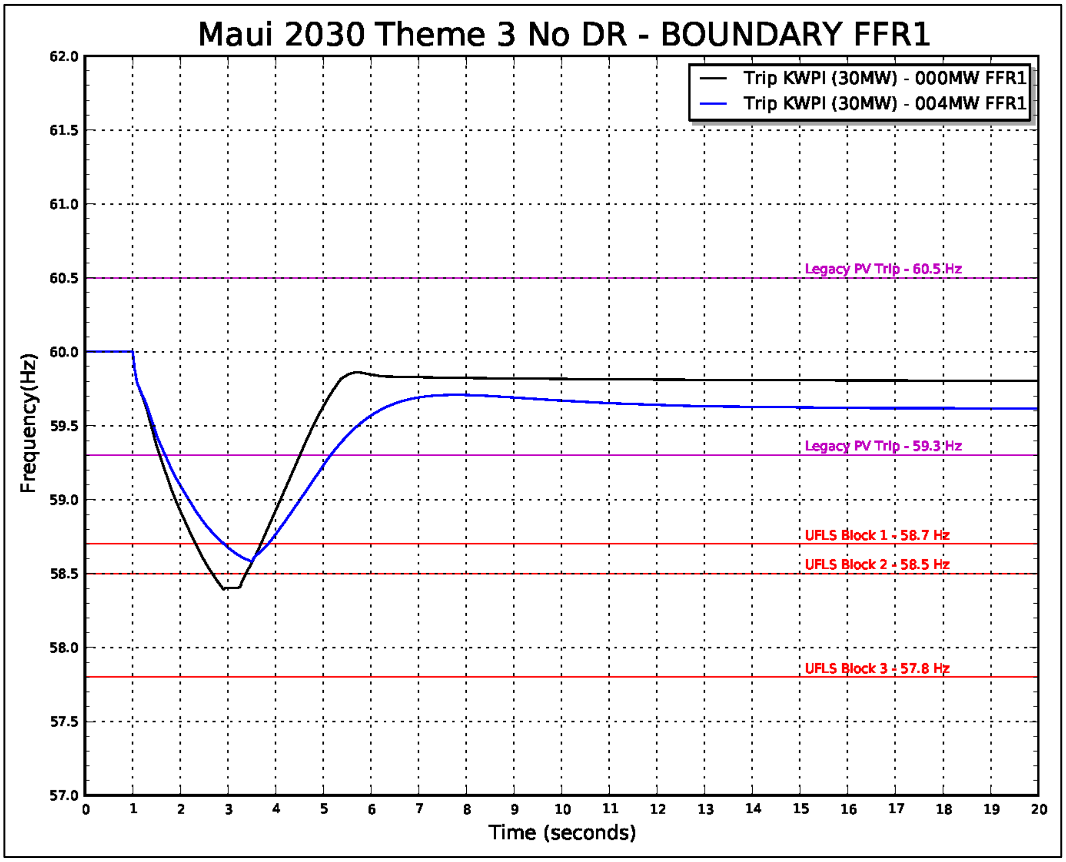

Figure O-242. Frequency Response Profile for FFR1 Boundary Hour

Figure O-242 shows the frequency response profile for a KWP1 trip at 30 MW for a boundary hour. System kinetic energy is 469 MW-sec. With no FFR, the frequency nadir is 58.4 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 4 MW.

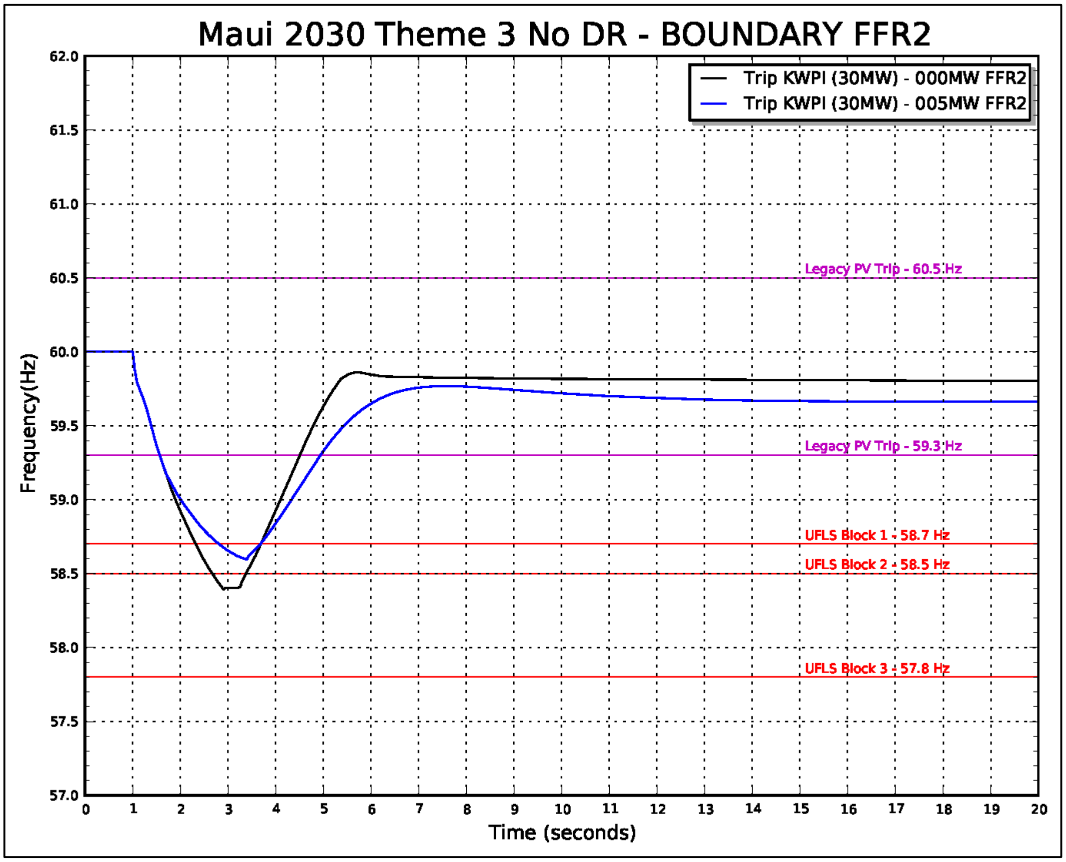

Figure O-243. Frequency Response Profile for FFR2 Typical Hour

Figure O-243 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW.

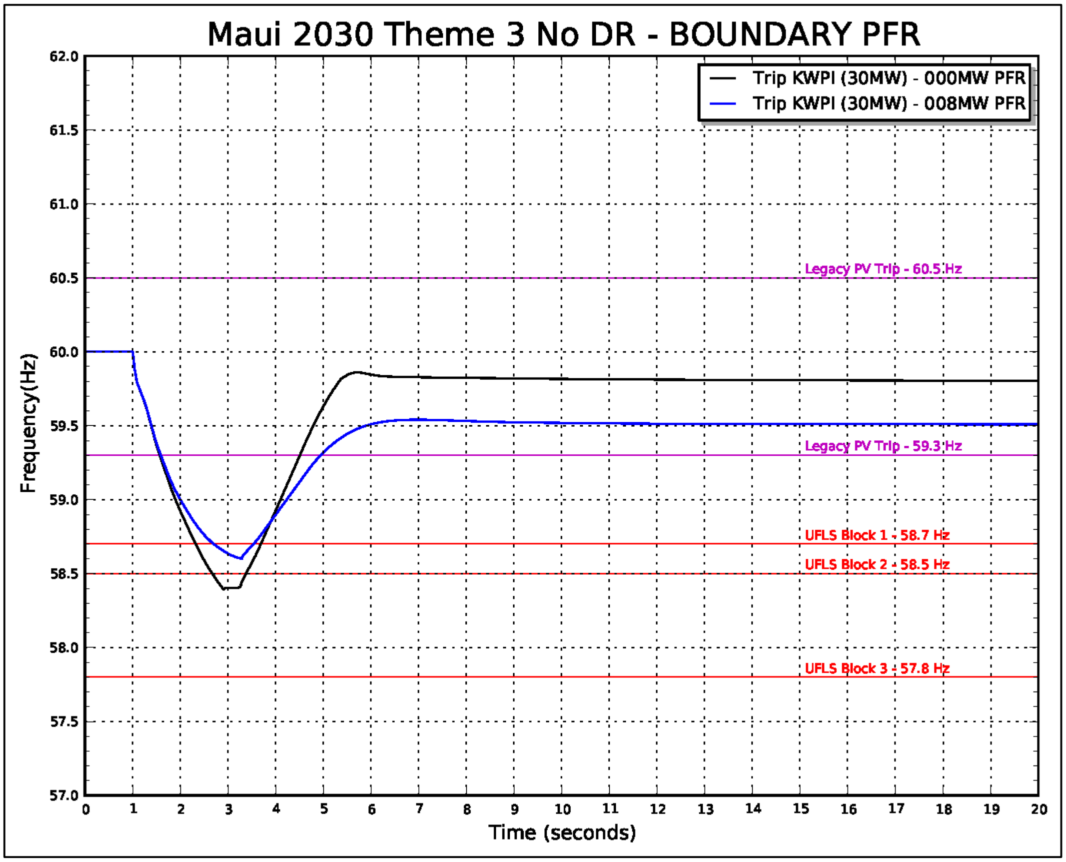

Figure O-244. Frequency Response Profile for PFR Boundary Hour

Figure O-244 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 8 MW.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production simulation data to represent a boundary condition.

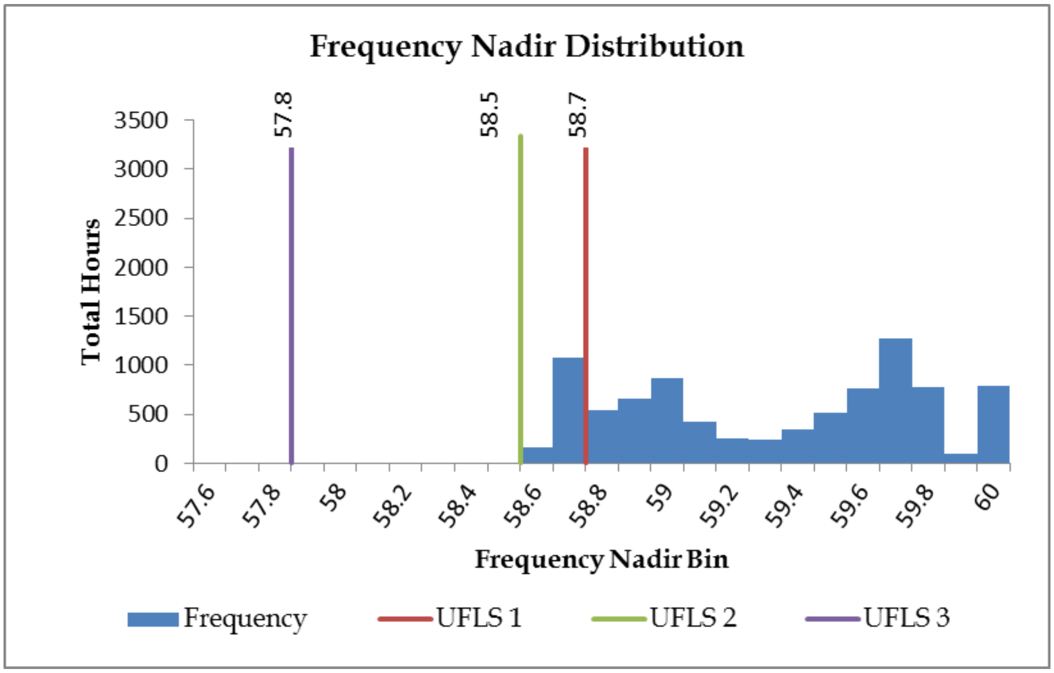

Figure O-245. Frequency Nadir Histogram for 2045

Figure O-245 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The system is in compliance with TPL-001 for the entire year.

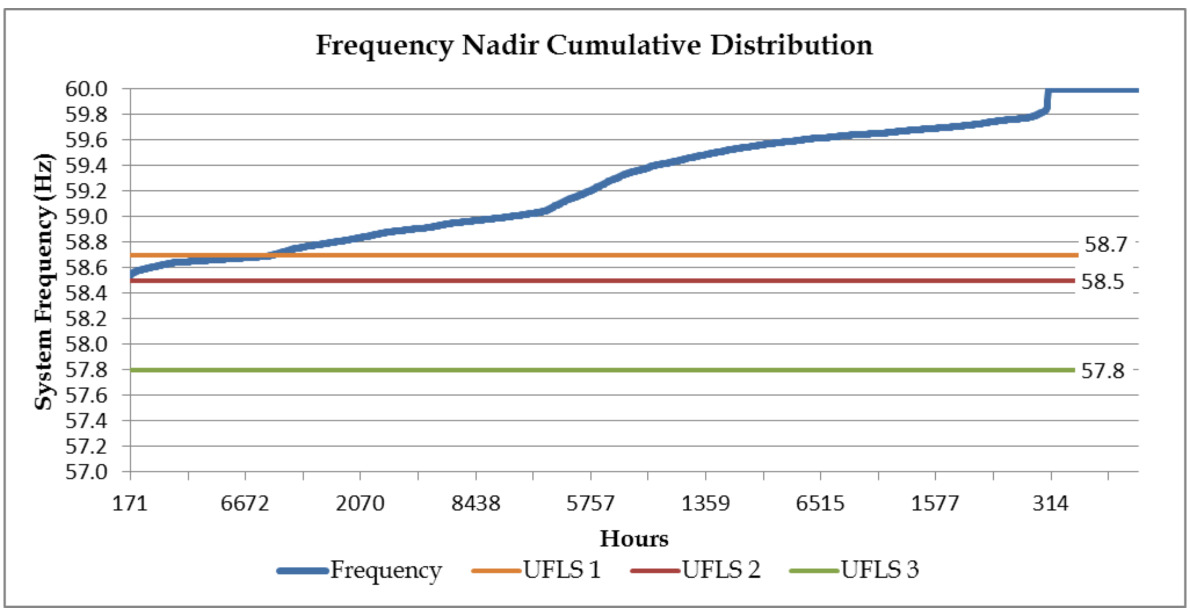

Figure O-246. Frequency Nadir Duration Curve 2045

Figure O-246 shows the frequency nadir duration curve for the Theme 3 resource plan in 2045.

Unit	Unit Ratings					Theme 3 - KWP I Trip Boundary Thu 4/11/2045 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Biomass 1	20.0	7.0	3.48	25.0	87	7.0	13.0	3.5
Biomass 2	20.0	7.0	3.48	25.0	87	7.0	13.0	3.5
Biomass 3	20.0	7.0	3.48	25.0	87	7.0	13.0	3.5
Geothermal 1	20.0	5.0	3.28	25.0	82	6.0	14.0	2.7
Geothermal 2	20.0	5.0	3.48	25.0	87	6.0	14.0	2.5
Maalaea 14	20.0	5.9	2.02	26.8	58			
Maalaea 15	13.0	5.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
ICE9_1	9.0	4.6	1.00	11.3	11			
ICE9_2	9.0	4.6	1.00	11.3	11			
Kahului 1	0.0	0.0	2.62	6.3	16		*Synchronous Condenser*	
Kahului 2	0.0	0.0	2.62	6.3	16		*Synchronous Condenser*	
Kahului 3	0.0	0.0	3.27	13.5	44		*Synchronous Condenser*	
Kahului 4	0.0	0.0	1.74	15.6	27		*Synchronous Condenser*	
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Total Wind	162					82		
-KWP	30	0				28		
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0				11		
-New Wind 2	30	0				11		
-New Wind 3	30	0				11		
Total Utility PV	80							
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	159.7	0						
DER Grid Ex	37.138	0						
Total System MVA							532	
Total Kinetic Energy							638	
Total Load							114	
Total Thermal Generation							33	
Total Renewable Generation							82	
Total Generation							115	
Excess Generation							1	
Regulation Requirement							0	
Total Up Regulation							0	
Total Down Regulation							0	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0

Table O-101. Unit Commitment and Dispatch 2045

Table O-101 shows the unit commitment and dispatch for the boundary hour (4/11/2045, 4:00 AM).

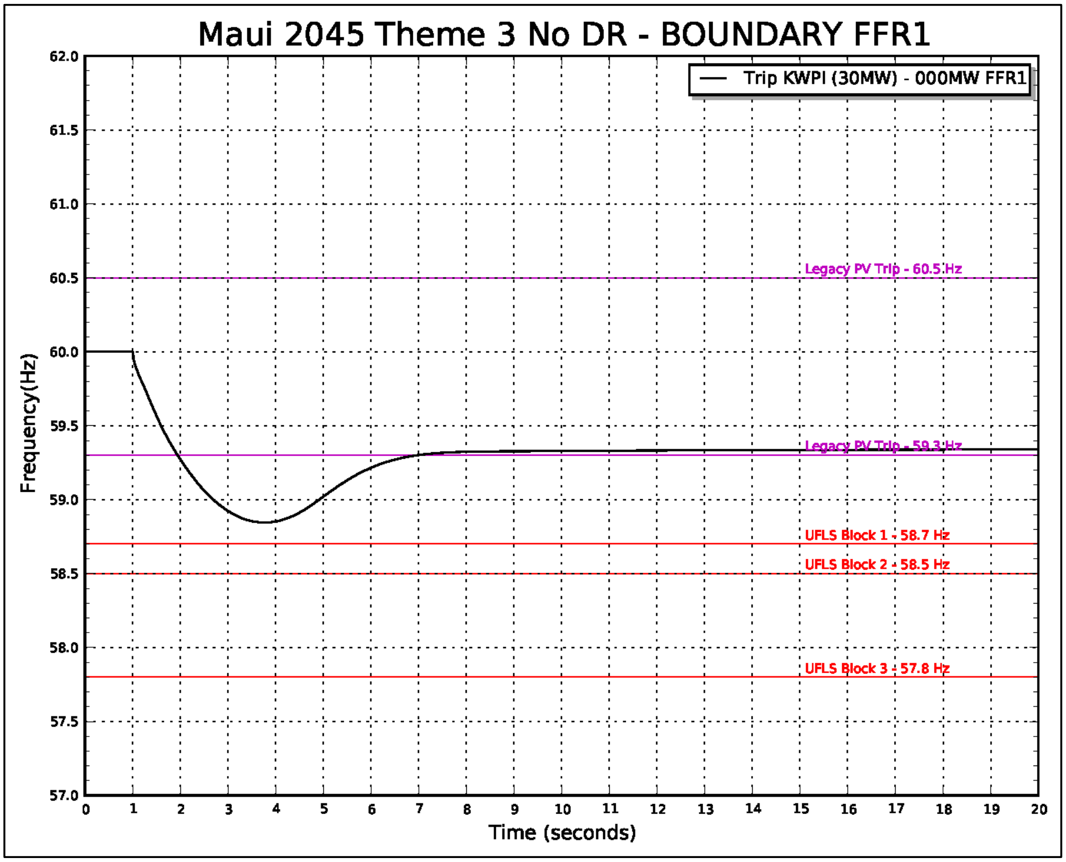

Figure O-247. Frequency Response Profile for FFR1 Boundary Hour

Figure O-247 shows the frequency response profile for a KWP 1 Trip at 30 MW for a boundary hour. System kinetic energy is 638 MW-sec which is significantly higher than previous years due to the addition of the firm renewable resources. The system is in compliance with TPL-001 so no additional resources are required.

Post April DR Plan

System security analysis performed on the Post April DR resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021. Maui does not have FFR2 capacities in their Demand Response portfolio.

2019

System security analysis performed on the Post April DR resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Maui transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirements of 73 MVA on the 69 kV system and 29 MVA on the 23 kV system. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Analysis Tue 8/20/2019 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.8	12.3	2.9
Maalaea 15	13.0	5.0	2.46	18.5	46	7.4	5.6	2.4
Maalaea 16	21.1	5.9	2.02	26.8	54	8.9	12.2	3.0
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	72					63		
-KWP	30	0				23		
-Auwahi	21	0				20		
-KWPII	21	0				20		
Station PV	6.74	0				6		
DGPV	121	0				92		
Total System MVA						117		
Total Kinetic Energy						328		
Total Load						192		
Total Thermal Generation						31		
Total Renewable Generation						161		
Total Generation						193		
Excess Generation						1		
Regulation Requirement						0		
Total Up Regulation						30		
Total Down Regulation						8		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		
	60.5Hz Capacity			69.5		60.5Hz Output		

Table O-102. Unit Commitment and Dispatch 2019 QV Analysis

Table O-102 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Tue 8/20/2019 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	1.5	5.7	1.5
Kahului 4	9.4	0.0	1.5	7.9	1.5
Maalaea 14	4.1	0.0	4.2	-0.1	4.2
Maalaea 15	2.9	0.0	3.6	-0.7	3.6
Maalaea 16	4.1	0.0	4.3	-0.2	4.3
Maalaea 17	15.0	0.0			
Maalaea 18	12.0	0.0			
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0			
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0.0			
Sml Sync Condenser 1	16.0	-16.0	11.0	5.0	27.0
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	1.4	13.1	1.6
-Auwahi	6.5	-6.5	0.9	5.6	7.4
-KWPII	10.2	0.0	1.4	8.8	1.4
-New Wind 1	9.9	0.0			
-New Wind 2	9.9	0.0			
-New Wind 3	9.9	0.0			
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			26.0		
Total Renewable MVAR Generation			3.7		
Total Cap Bank MVAR			51.8		
Charging MVAR			5.0		
Total MVAR Supply			86.5		
Total MVAR Load			32.3		
Total MVAR Losses			26.9		
Excess MVAR Generation			27.4		
Total MVAR Supply Capability				45	
Total MVAR Absorb Capability					42.0

Table O-103. MVAR Capability 2019 QV Analysis

Table O-103 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
101	Kahului PP-Wailuku 23 kV
102	Maalaea-Kihei
104	Maalaea-Waiinu
113	Wailea-Auwahi 69 KV
114	Wailea-Kihei 69 kV

Table O-104. N-1 Contingencies 2019 QV Analysis

Table O-104 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

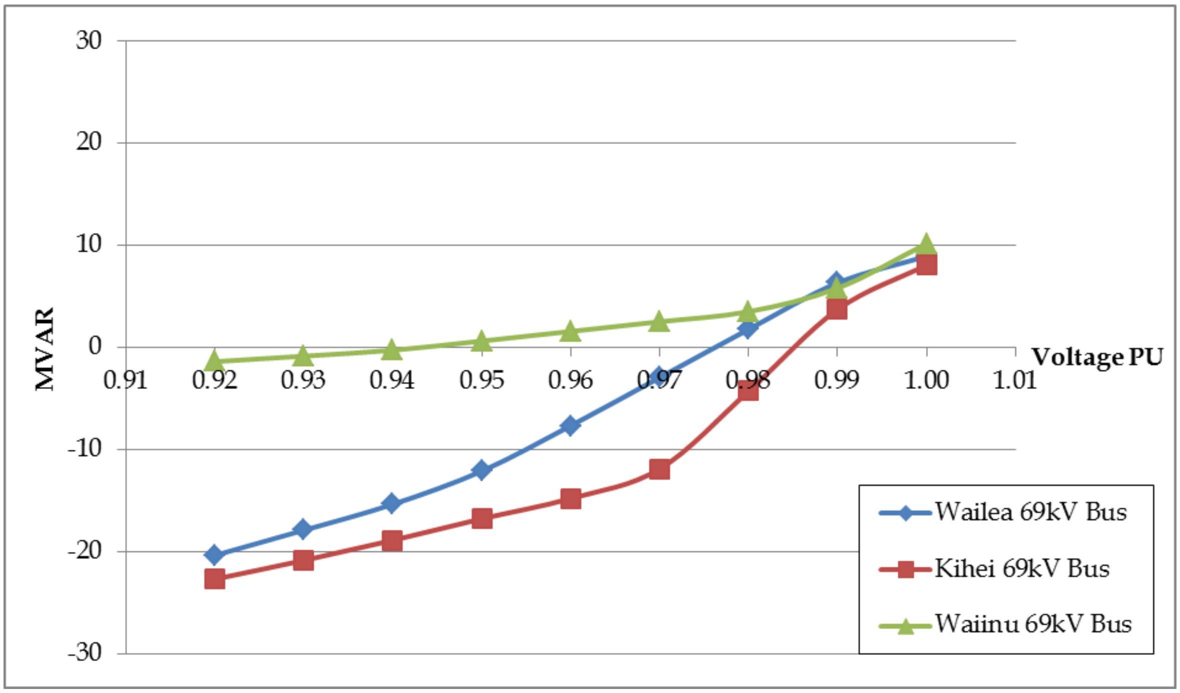

Figure O-248. QV Curves 2019

Figure O-248 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	113	9	113	6	113	2	113	-3	113	-8	113	-12	114	-15	114	-18	114	-20
35	Kihei 69 kV Bus	113	8	113	4	113	-4	113	-12	102	-15	102	-17	102	-19	102	-21	102	-23
636	Waiinu 69 kV Bus	101	10	115	6	104	4	104	3	104	2	104	1	104	0	104	-1	104	-1

Table O-105. Summary of Results 2019 QV Analysis

Table O-105 shows the results of the QV analysis for 2019. The Waiinu Bus requires 1 MVAR but for the purpose of this analysis, the reactive power requirement for the system is met.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data that represents a typical and boundary condition.

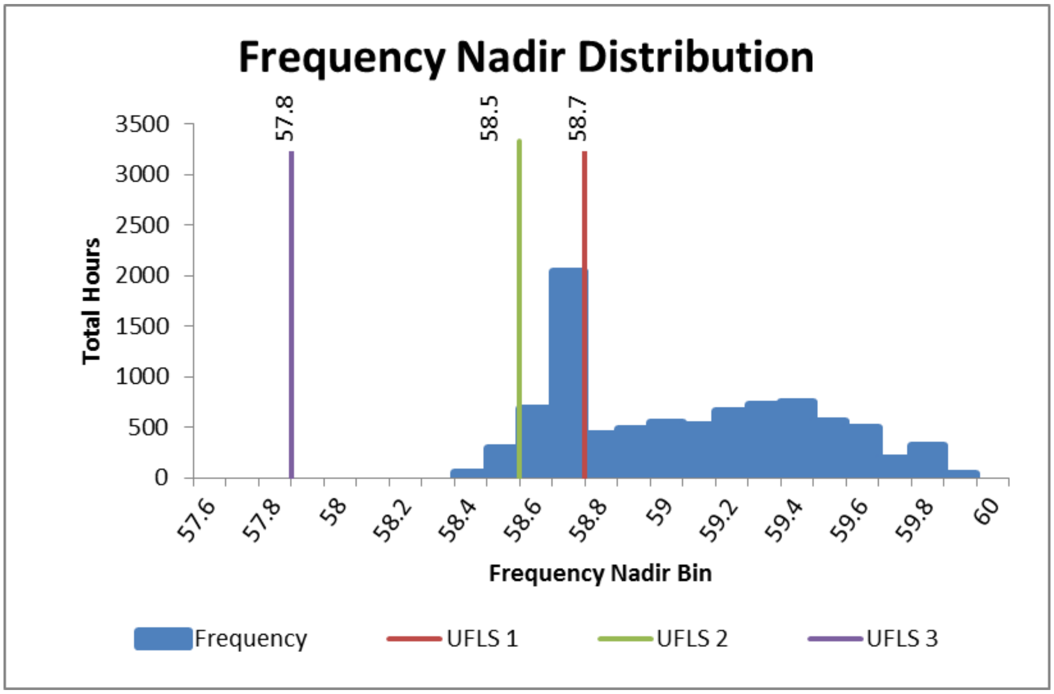

Figure O-249. Frequency Nadir Histogram for 2019

Figure O-249 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 288 hours was 12:00 PM on Monday, April 8. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 51 hours was 3:00 AM on Wednesday, June 5. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

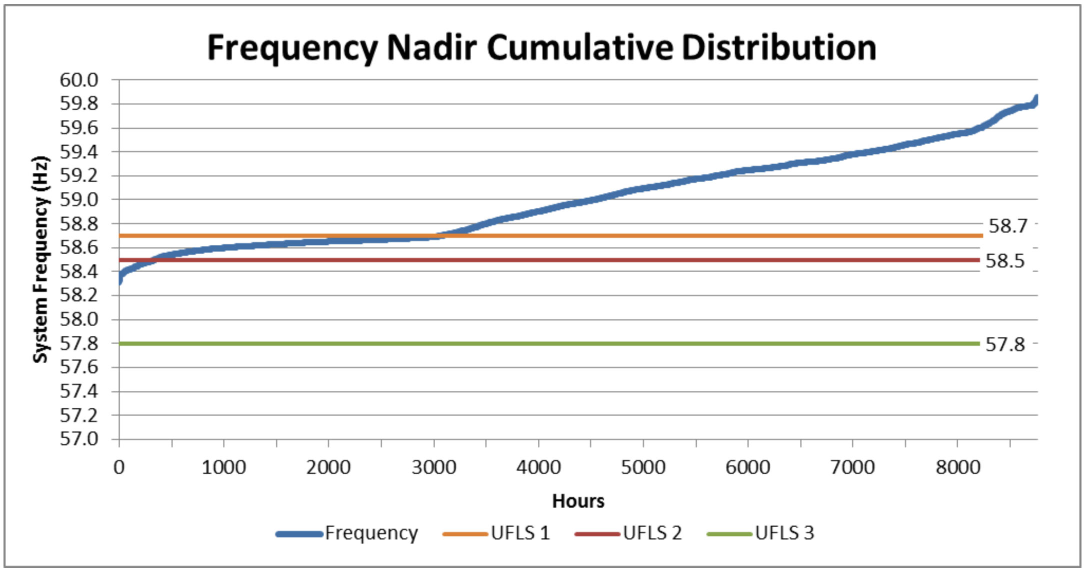

Figure O-250. Frequency Nadir Duration Curve 2019

Figure O-250 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of exceeding the UFLS requirements of TPL-001 for 340 hours of the year.

Unit	Unit Ratings					DR- KWP I Trip Typical Mon 4/8/2019 Hour 12			DR - KWP I Trip Boundary Wed 6/5/2019 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	4.1	7.4	1.1	8.1	3.4	5.1
Kahului 4	11.5	3.0	3.48	15.6	54	4.7	6.8	1.7	5.4	6.1	2.4
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0			
Maalaea 15	13.0	5.0	2.46	18.5	46				6.5	6.5	1.5
Maalaea 16	21.1	5.9	2.02	26.8	54	8.9	12.2	3.0	21.1	0.0	15.2
Maalaea 17	21.1	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	21.1	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16	5.5	0.0	3.6			
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*			*Synchronous Condenser*	
Total Wind	72					50			57		
-KWP	30	0				30			30		
-Auwahi	21	0							7		
-KWPII	21	0				21			20		
Station PV	6.74	0				6					
DGPV	121	0				85					
Total System MVA							106			90	
Total Kinetic Energy							299			270	
Total Load							177			98	
Total Thermal Generation							32			41	
Total Renewable Generation							142			57	
Total Generation							174			98	
Excess Generation							-3			-1	
Regulation Requirement							0			0	
Total Up Regulation							24			6	
Total Down Regulation							10			17	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		4.7	59.3Hz Output		
		60.5Hz Capacity		69.5		60.5Hz Output		45.1	60.5Hz Output		

Table O-106. Unit Commitment and Dispatch 2019

Table O-106 shows the unit commitment and dispatch for the typical hour (4/8/19, 12:00 PM) and boundary hour (6/5/19, 3:00 AM).

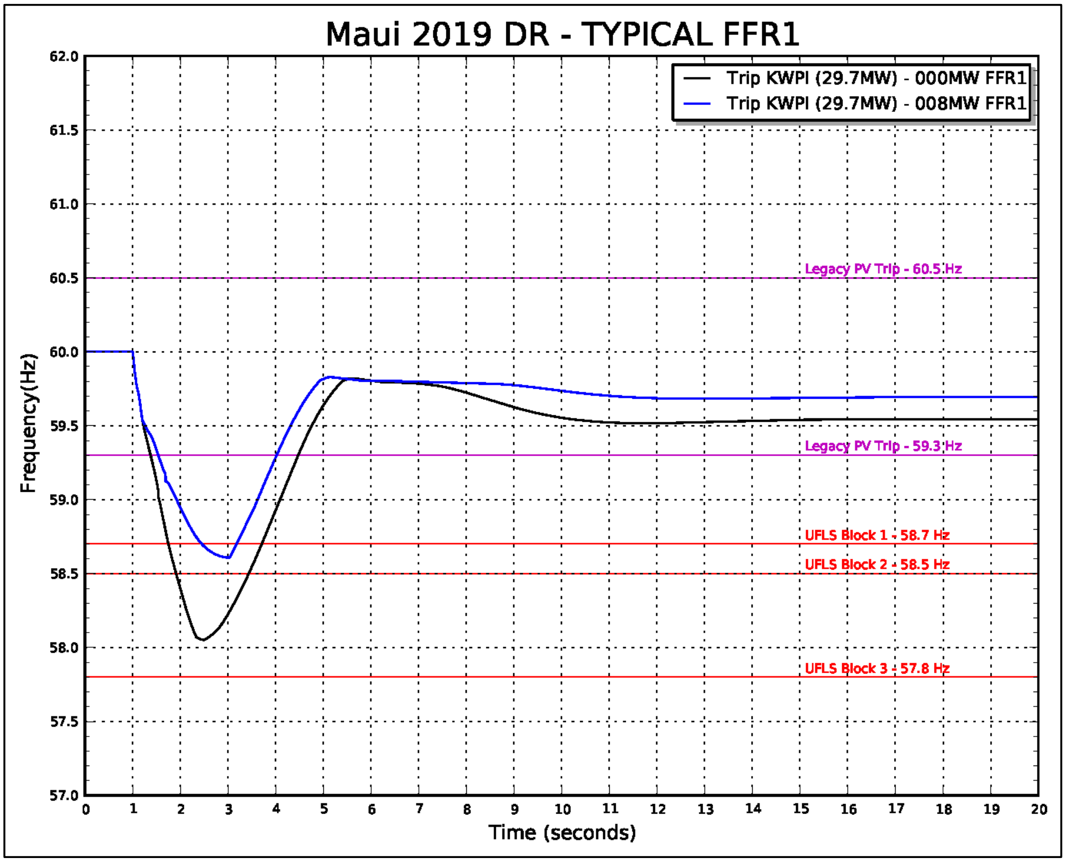

Figure O-251. Frequency Response Profile for FFR1 Typical Hour

Figure O-251 shows the frequency response profile for a KWP I trip at 29.7 MW for a typical hour. System kinetic energy is 299 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.7 MW. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

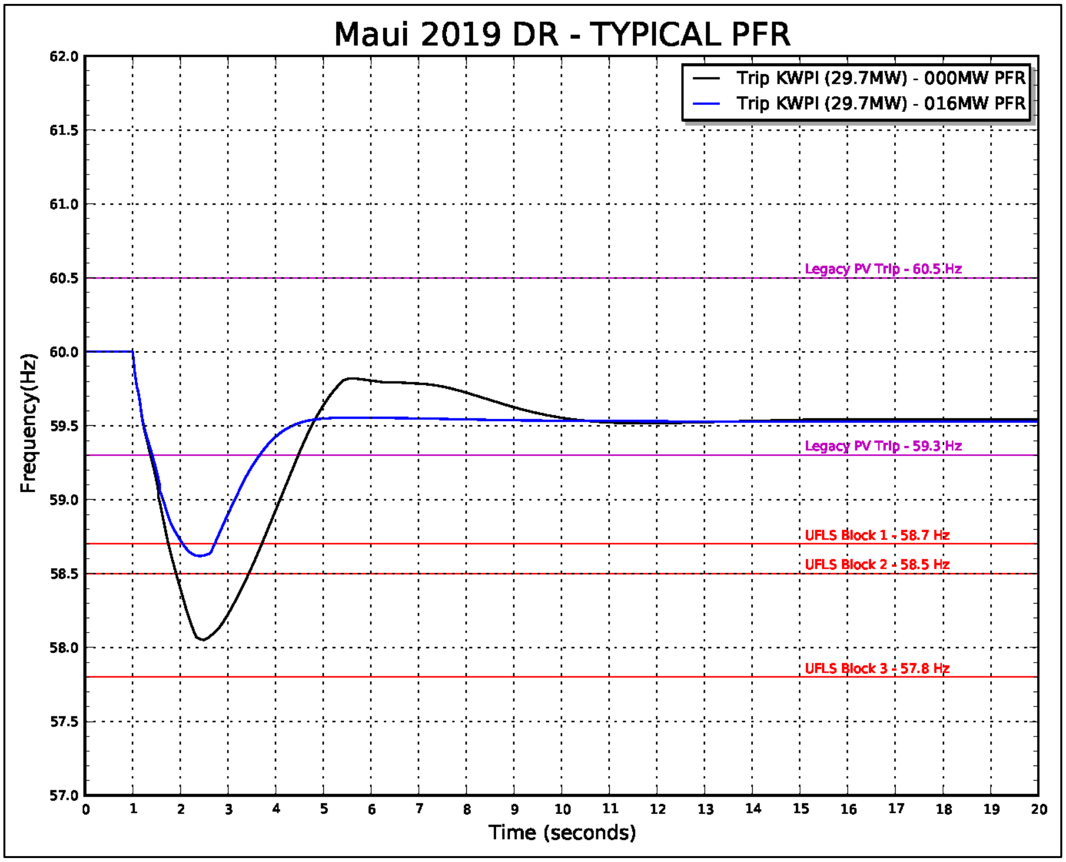

Figure O-252. Frequency Response Profile for PFR Typical Hour

Figure O-252 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 16 MW. This is in addition to the 24 MW of upward regulation from thermal generation.

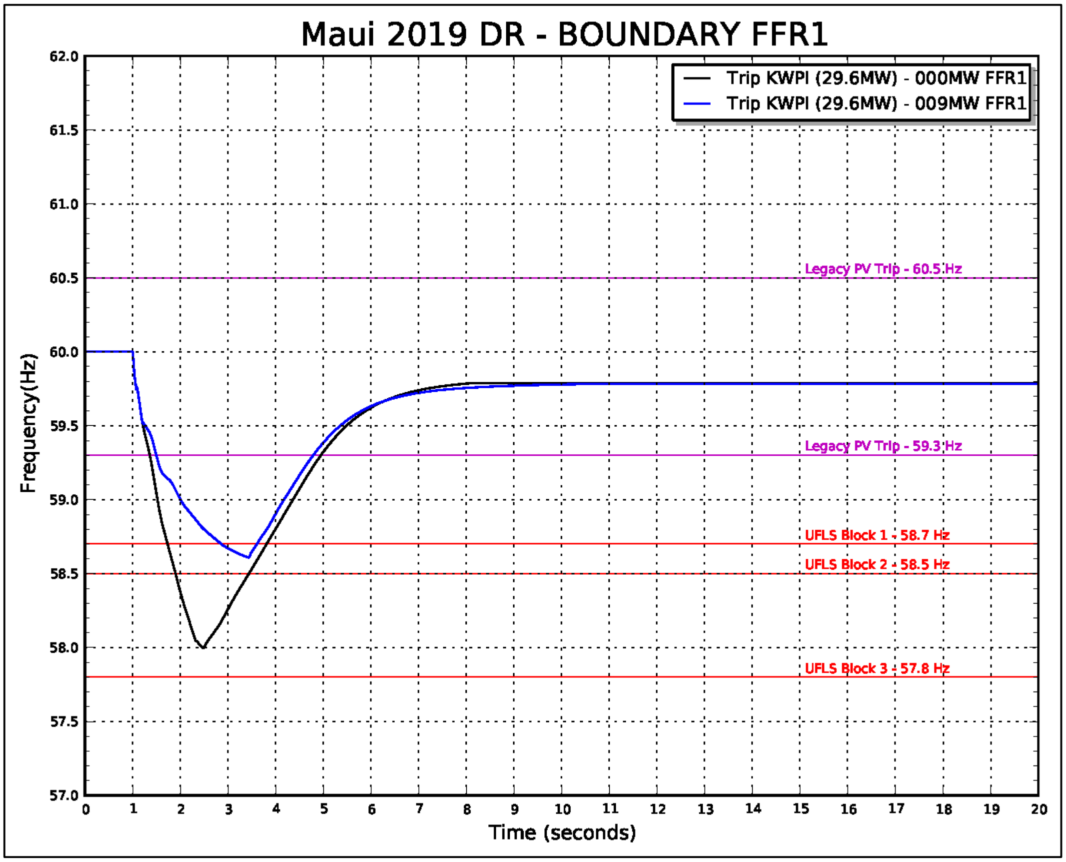

Figure O-253. Frequency Response Profile for FFR1 Boundary Hour

Figure O-253 shows the frequency response profile for a KWP 1 trip at 29.6 MW for a boundary hour. System kinetic energy is 270 MW-sec. With no FFR, the frequency nadir is 58.0 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

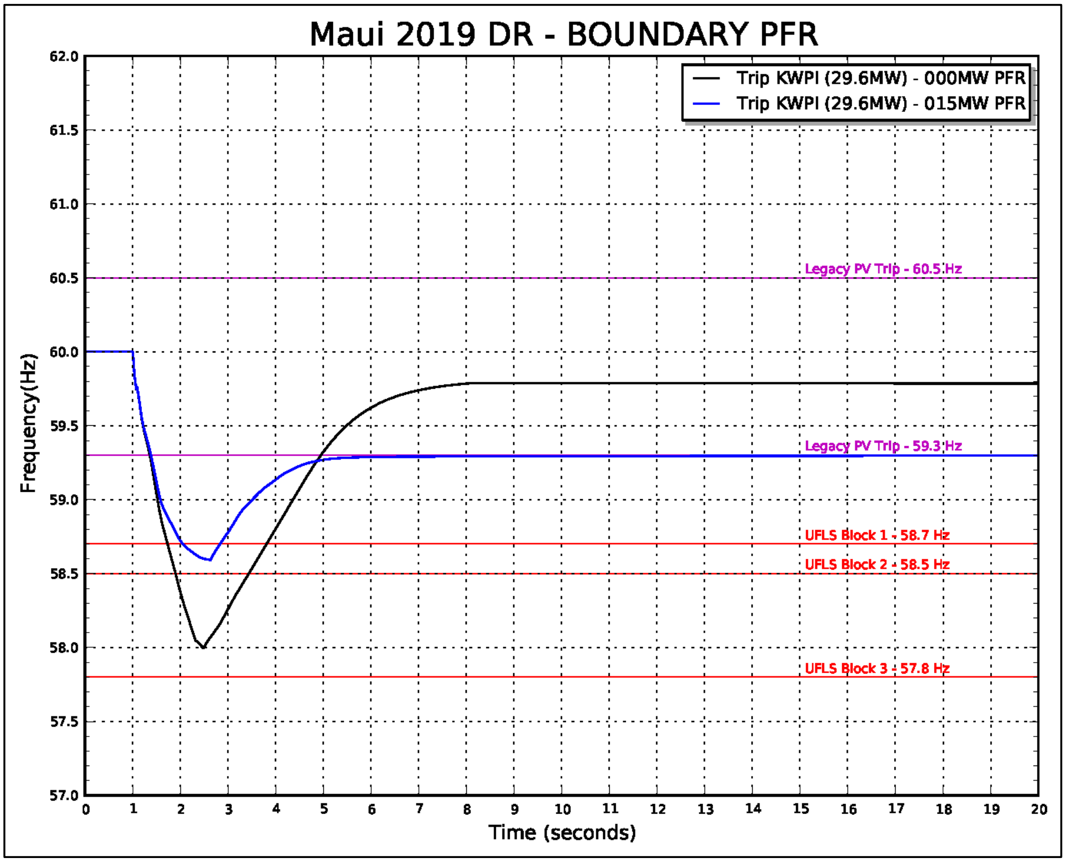

Figure O-254. Frequency Response Profile for PFR Boundary Hour

Figure O-254 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 16 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					DR - Fault Sat 5/11/2019 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	28.8	58	10.2	11.0	4.2
Maalaea 15	13.0	5.0	2.46	18.5	46	9.1	3.9	4.1
Maalaea 16	21.1	5.9	2.02	26.8	54	12.0	9.2	6.1
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16	5.5	0.0	3.6
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	72					14		
-KWP	30	0						
-Auwahi	21	0				14		
-KWPII	21	0						
Station PV	6.74	0				6		
DGPV	121	0				96		
Total System MVA							126	
Total Kinetic Energy							344	
Total Load							162	
Total Thermal Generation							43	
Total Renewable Generation							117	
Total Generation							159	
Excess Generation							-3	
Regulation Requirement							0	
Total Up Regulation							41	
Total Down Regulation							18	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.3
	60.5Hz Capacity			69.5		60.5Hz Output		50.7

Table O-107. Unit Commitment and Dispatch Fault Analysis 2019

Table O-107 shows the unit commitment and dispatch for the 69 kV fault analysis (5/11/19, 1:00 PM). Inverter-based generation is 96 MW.

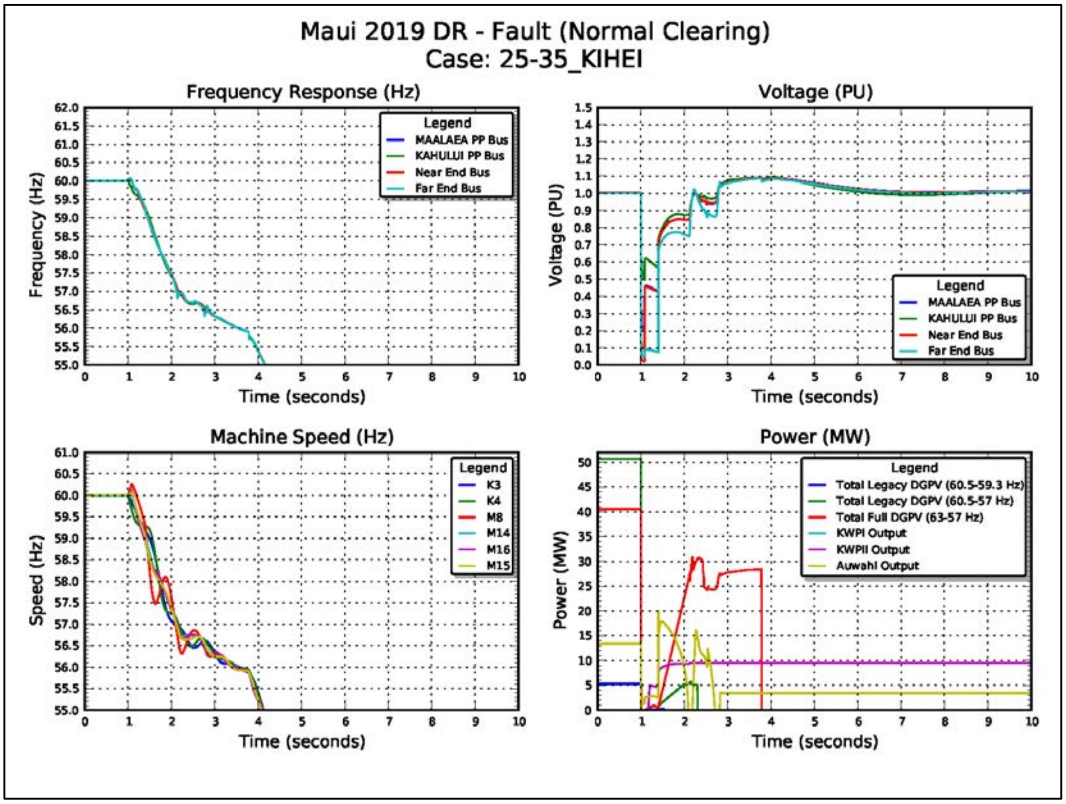

Figure O-255. System Performance for Normally Cleared Fault

Figure O-255 shows the system performance for a normally cleared fault at the Kihei end of the Wailea-Kihei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 96 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

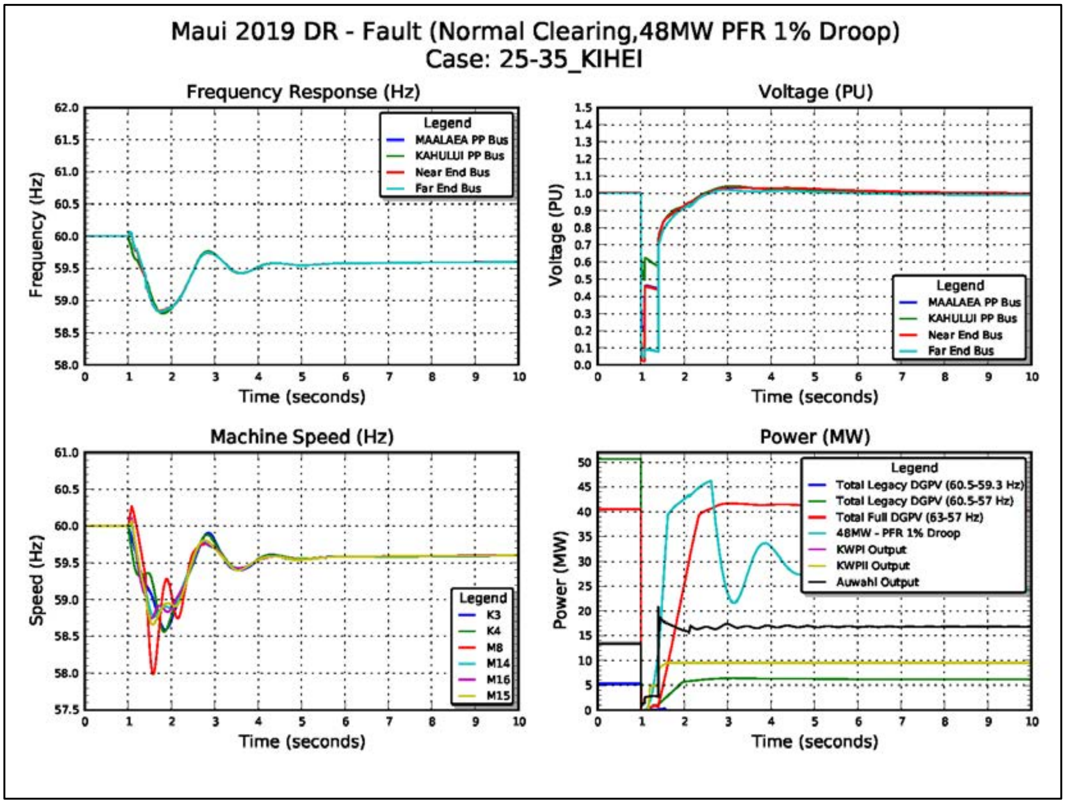

Figure O-256. Normally Cleared Fault Sensitivity 48 MW PFR

Figure O-256 shows system performance with the addition of 48 MW PFR at 1% droop response. For the purpose of this analysis, a 48 MW BESS was located at Maʻalaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 48 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2019 DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 48MW PFR 1% Droop	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable	Stable	Stable
	Kanaha	Stable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Stable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Stable	Stable	Stable
	Waiinu	Unstable	Unstable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Unstable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Stable	Stable	Stable
	Kula AG	Stable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Stable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Stable	Stable	Stable
	Kula AG	Stable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR1	Stable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR2	Stable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Stable	Stable	Stable
	Kanaha FDR3	Stable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Stable	Stable	Stable
	Pukalani	Stable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Stable	Stable	Stable
	Pukalani	Stable	Stable	Stable

Table O-108. Summary of Results Fault Analysis

Table O-108 shows the results of the 69 kV fault analysis with 48 MW PFR. The Maʻalaea-Waiinu and Maʻalaea–Puʻunene circuit faults could not be stabilized. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Analysis Wed 8/5/2020 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0
Maalaea 15	13.0	3.0	2.46	18.5	46			
Maalaea 16	21.1	5.9	2.02	26.8	54	8.8	12.3	2.9
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*	
Total Wind	72					70		
-KWP	30	0				19		
-Auwahi	21	0				19		
-KWPII	21	0				19		
-New Wind 1	30	0						
-New Wind 2	30	0				7		
-New Wind 3	30	0				7		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	6.74	0				6		
DGPV	121	0				92		
Total System MVA							129	
Total Kinetic Energy							335	
Total Load							192	
Total Thermal Generation							24	
Total Renewable Generation							168	
Total Generation							192	
Excess Generation							0	
Regulation Requirement							0	
Total Up Regulation							42	
Total Down Regulation							6	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		4.8
		60.5Hz Capacity		69.5		60.5Hz Output		45.8

Table O-109. Unit Commitment and Dispatch 2020 QV Analysis

Table O-109 shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Wed 8/5/2020 Hour 13		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	1.5	5.7	1.5
Kahului 4	9.4	0.0	1.5	7.9	1.5
Maalaea 14	4.1	0.0	2.6	1.5	2.6
Maalaea 15	2.9	0.0	3.3	-0.4	3.3
Maalaea 16	4.1	0.0	4.3	-0.2	4.3
Maalaea 17	15.0	0.0			
Maalaea 18	12.0	0.0			
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0			
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0			
Sync Condenser 1	30.0	-30	8.3	21.7	38.3
Sync Condenser 1 - 23 kV	16.0	-16.0	3.5	12.5	19.5
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	1.5	13.0	1.7
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0			
-New Wind 2	9.9	0.0			
-New Wind 3	9.9	0.0			
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			24.9		
Total Renewable MVAR Generation			1.5		
Total Cap Bank MVAR			53.3		
Charging MVAR			5.6		
Total MVAR Supply			85.4		
Total MVAR Load			59.3		
Total MVAR Losses			23.9		
Excess MVAR Generation			2.1		
Total MVAR Supply Capability				78	
Total MVAR Absorb Capability					70.9

Table O-110. MVAR Capability 2020 QV Analysis

Table O-110 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	Maalaea-Kihei
104	Maalaea-Waiinu
114	Wailea-Kihei 69 kV

Table O-111. N-1 Contingencies 2020 QV Analysis

Table O-111 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

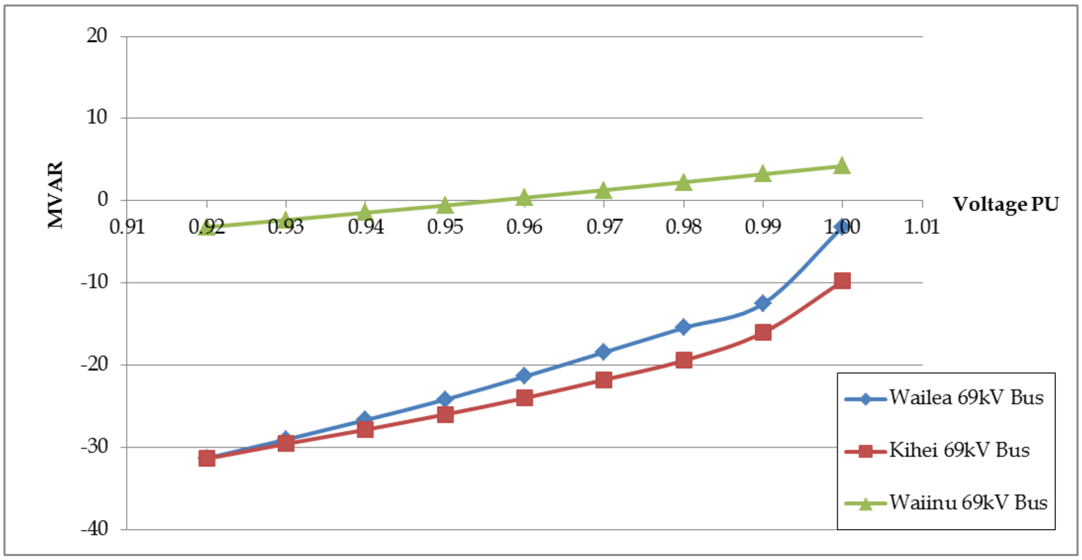

Figure O-257. QV Curves 2020

Figure O-257 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	114	-3	114	-13	114	-15	114	-18	114	-21	114	-24	114	-27	114	-29	114	-31
35	Kihei 69 kV Bus	102	-10	102	-16	102	-19	102	-22	102	-24	102	-26	102	-28	102	-30	102	-31
636	Waiinu 69 kV Bus	104	4	104	3	104	2	104	1	104	0	104	-1	104	-1	104	-2	104	-3

Table O-112. Summary of Results 2020 QV Analysis

Table O-112 shows the results of the QV analysis for 2020. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

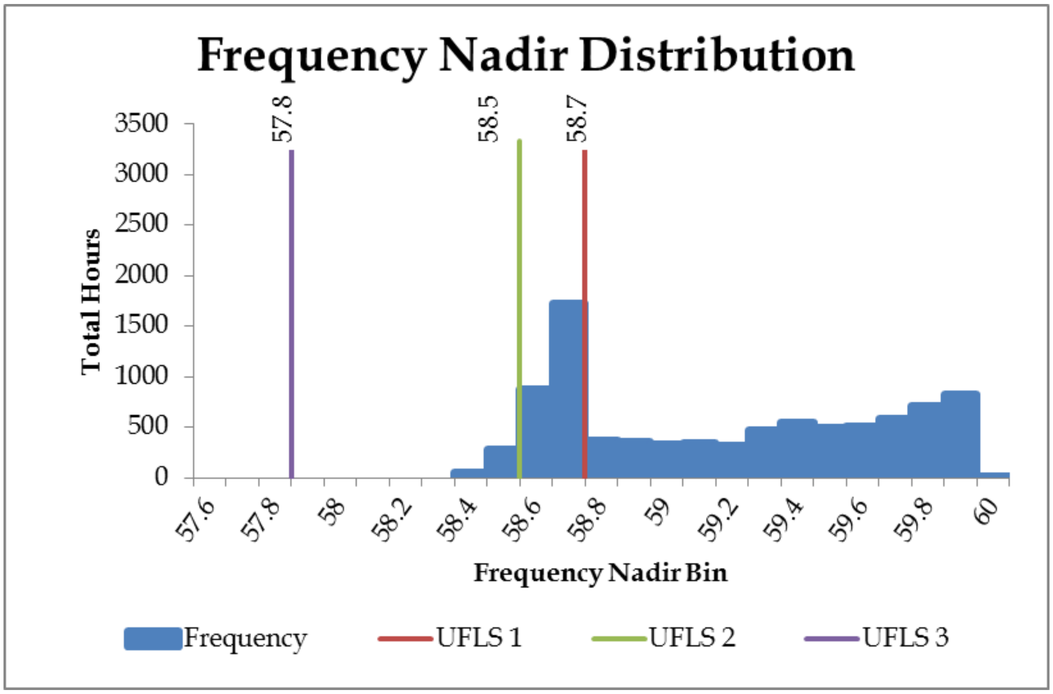

Figure O-258. Frequency Nadir Histogram for 2020

Figure O-258 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 284 hours was 12:00 PM on Thursday, November 26. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 49 hours was 3:00 AM on Thursday, November 26. The frequency nadir range for the boundary hour is 58.3 – 58.4 Hz that requires two blocks of UFLS to stabilize system frequency.

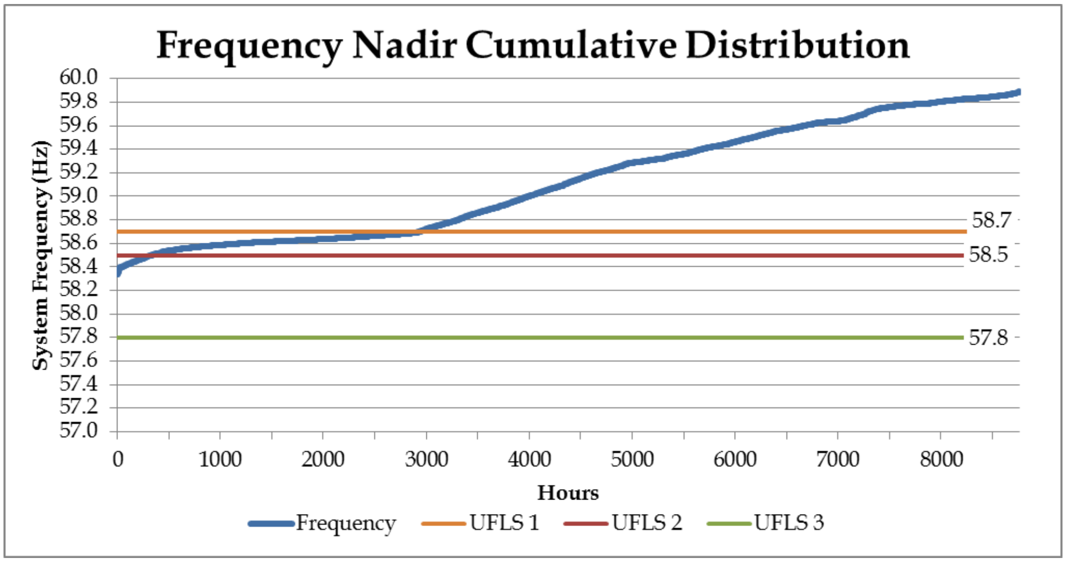

Figure O-259. Frequency Nadir Duration Curve 2020

Figure O-259 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of exceeding the UFLS requirements of TPL-001 for 309 hours of the year.

Unit	Unit Ratings					DR- KWP I Trip Typical Thu 11/26/2020 Hour 12			DR - KWP I Trip Boundary Thu 11/26/2020 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88						
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0	8.9	12.2	3.0
Maalaea 15	13.0	3.0	2.46	18.5	46	7.4	5.6	4.4	7.4	5.6	4.4
Maalaea 16	21.1	5.9	2.02	26.8	54	8.8	12.3	2.9	8.8	12.3	2.9
Maalaea 17	21.1	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	21.1	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*			*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*			*Synchronous Condenser*		
Total Wind	72					81			74		
-KWP	30	0				29			30		
-Auwahi	21	0									
-KWPII	21	0				21			21		
-New Wind 1	30	0				10			8		
-New Wind 2	30	0				11			8		
-New Wind 3	30	0				11			8		
Total Utility PV	80					0			0		
-Utility PV1	20	0									
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
Station PV	6.74	0				6			0%		
DGPV	121	0				60			0%		
Total System MVA						134			134		
Total Kinetic Energy						292			292		
Total Load						177			102		
Total Thermal Generation						28			28		
Total Renewable Generation						148			74		
Total Generation						176			102		
Excess Generation						-1			0		
Regulation Requirement						0			0		
Total Up Regulation						39			39		
Total Down Regulation						10			10		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		3.2	59.3Hz Output		
	60.5Hz Capacity			69.5		60.5Hz Output		30.6	60.5Hz Output		

Table O-113. Unit Commitment and Dispatch 2020

Table O-113 shows the unit commitment and dispatch for the typical hour (11/26/20, 12:00 PM) and boundary hour (11/26/20, 3:00 AM).

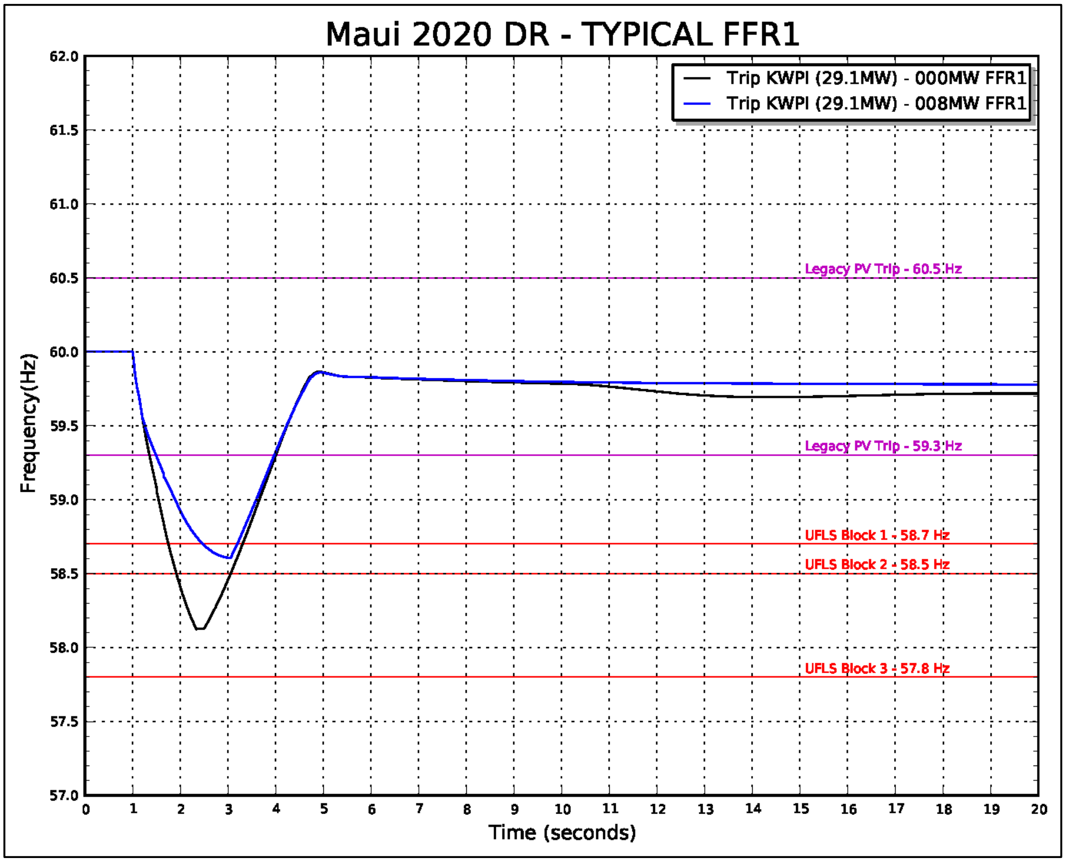

Figure O-260. Frequency Response Profile for FFR1 Typical Hour

Figure O-260 shows the frequency response profile for a KWP 1 trip at 29.1 MW for a typical hour. System kinetic energy is 292 MW-sec and the capacity of legacy PV that will disconnect from the system is 3.2 MW. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

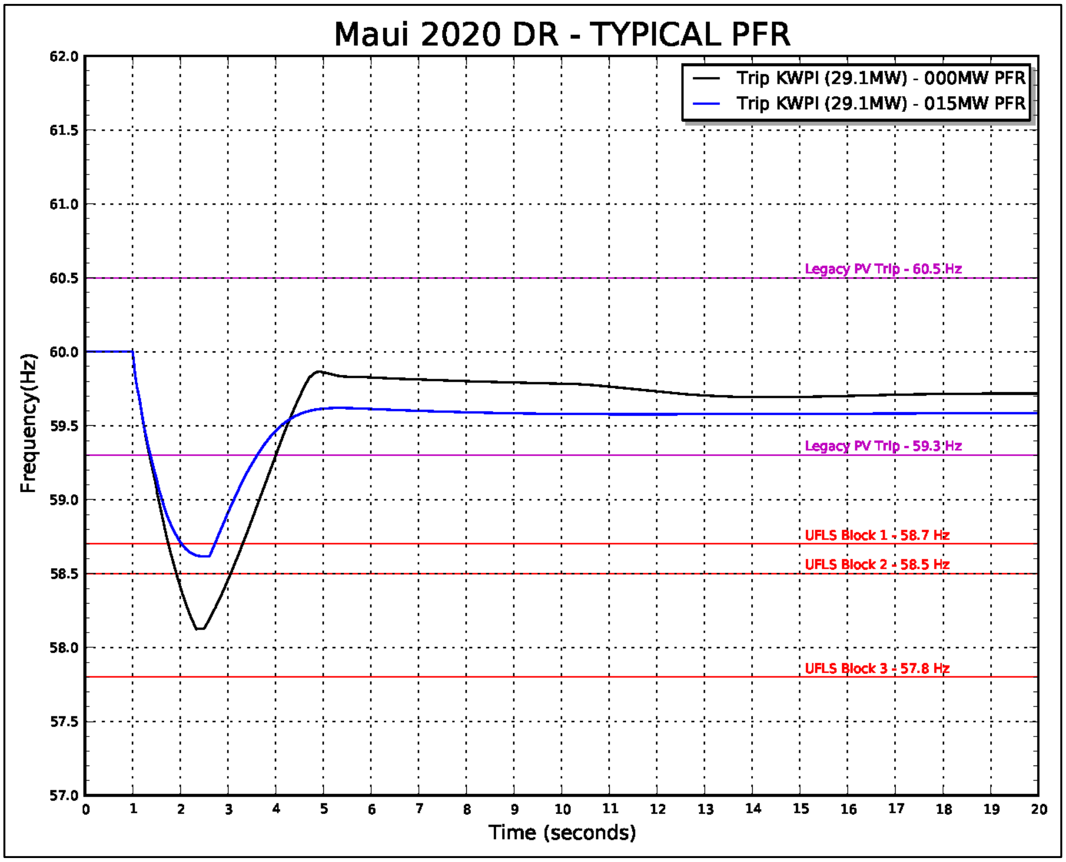

Figure O-261. Frequency Response Profile for PFR Typical Hour

Figure O-261 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

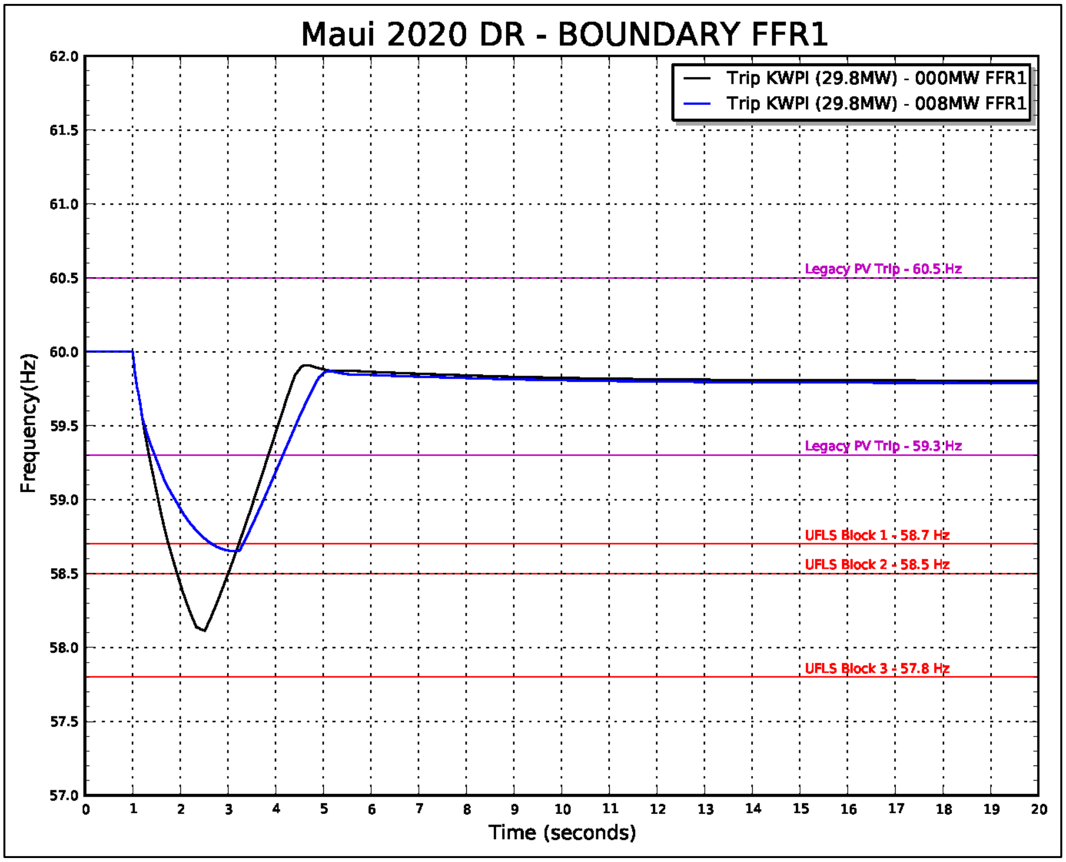

Figure O-262. Frequency Response Profile for FFR1 Boundary Hour

Figure O-262 shows the frequency response profile for a KWP 1 trip at 29.8 MW for a boundary hour. System kinetic energy is 292 MW-sec. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

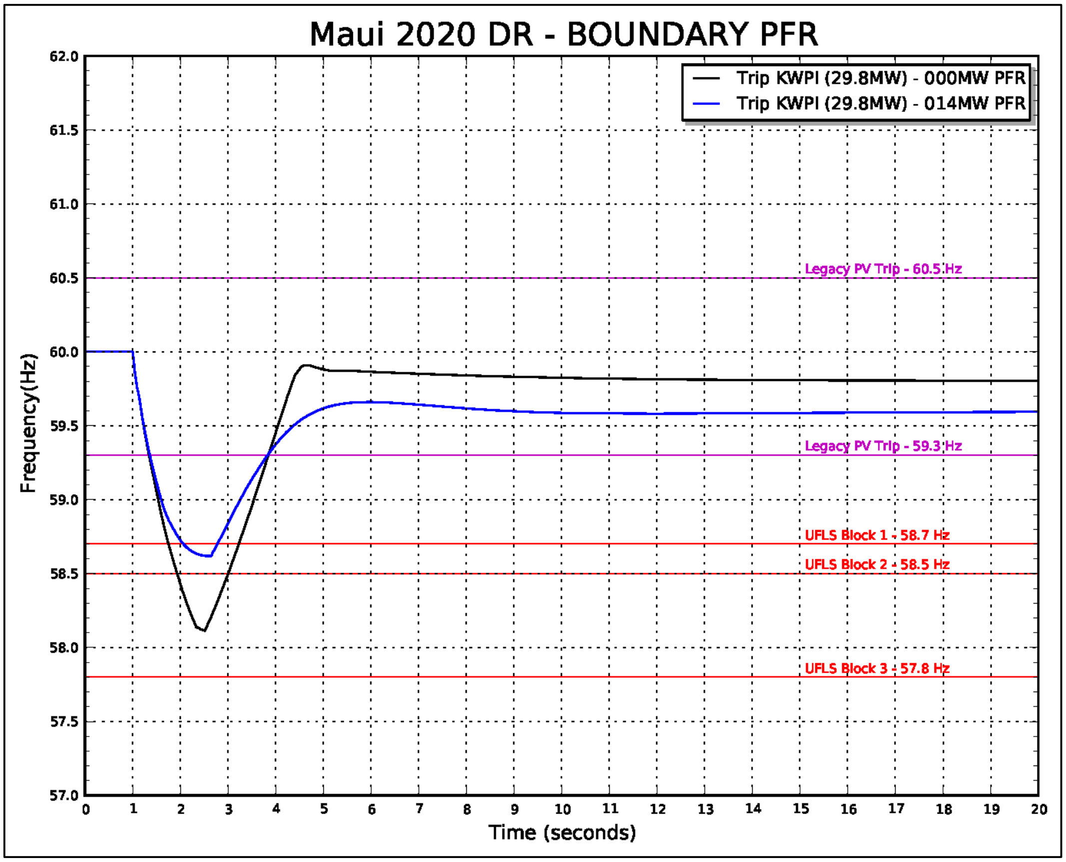

Figure O-263. Frequency Response Profile for PFR Boundary Hour

Figure O-263 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 39 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					DR - Fault Tue 5/12/2020 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58			
Maalaea 15	13.0	3.0	2.46	18.5	46	3.7	9.3	0.7
Maalaea 16	21.1	5.9	2.02	26.8	54	11.9	9.3	6.0
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	72					46		
-KWP	30	0				26		
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0						
-New Wind 2	30	0						
-New Wind 3	30	0						
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	6.74	0				6		
DGPV	121	0				102		
Total System MVA						120		
Total Kinetic Energy						322		
Total Load						180		
Total Thermal Generation						22		
Total Renewable Generation						155		
Total Generation						177		
Excess Generation						-3		
Regulation Requirement						0		
Total Up Regulation						36		
Total Down Regulation						7		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.3
	60.5Hz Capacity			69.5		60.5Hz Output		51.4

Table O-114. Unit Commitment and Dispatch Fault Analysis 2020

Table O-114 shows the unit commitment and dispatch for the 69 kV fault analysis (5/12/20, 1:00 PM). Inverter-based generation is 102 MW.

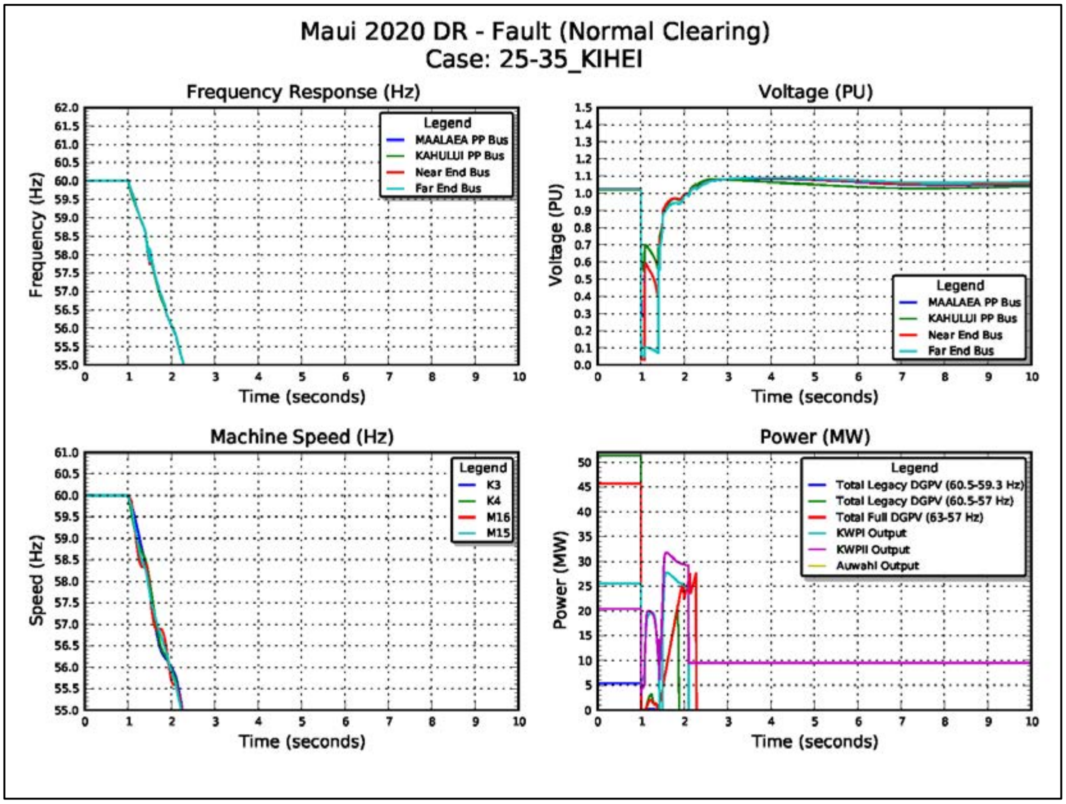

Figure O-264. System Performance for Normally Cleared Fault

Figure O-264 shows the system performance for a normally cleared fault at the Kihei end of the Wailea-Kihei circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 102 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

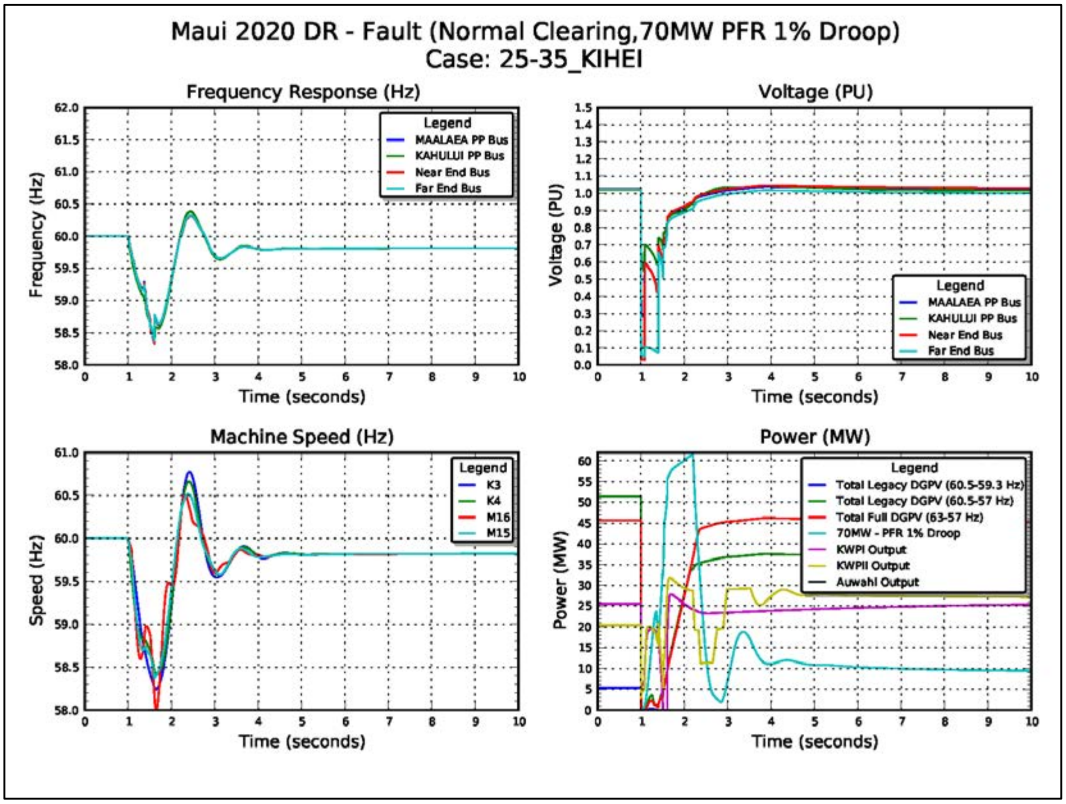

Figure O-265. Normally Cleared Fault Sensitivity 70 MW PFR

Figure O-265 s shows system performance with the addition of 70 MW PFR at 1% droop response. For the purpose of this analysis, a 70 MW BESS was located at Ma‘alaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 70 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2020 DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation: 70MW PFR 1% Droop	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable	Stable	Stable
	Kanaha	Stable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Unstable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Stable	Stable	Stable
	Waiinu	Unstable	Unstable	Stable
MPP-Puunene 69kV	MPP	Unstable	Unstable	Stable
	Puunene	Unstable	Unstable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Unstable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR1	Unstable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR2	Unstable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR3	Unstable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-115. Summary of Results Fault Analysis 2020

Table O-115 shows the results of the 69 kV fault analysis with 70 MW PFR. The Lahaina-Lahaina Luna, Maʻalaea-Waiinu and Maʻalaea–Puʻunene circuit faults could not be stabilized. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Analysis Thu 8/19/2021 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	3.0	8.5	0.0
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	11.9	9.3	6.0
Maalaea 15	13.0	3.0	2.46	18.5	46	3.7	9.3	0.7
Maalaea 16	21.1	5.9	2.02	26.8	54			
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*	
Total Wind	162					103		
-KWP	30	0				28		
-Auwahi	21	0				16		
-KWPII	21	0				15		
-New Wind 1	30	0				14		
-New Wind 2	30	0				15		
-New Wind 3	30	0				15		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	8	0				5		
DGPV	128	0				63		
Total System MVA							120	
Total Kinetic Energy							326	
Total Load							193	
Total Thermal Generation							22	
Total Renewable Generation							172	
Total Generation							193	
Excess Generation							0	
Regulation Requirement							0	
Total Up Regulation							36	
Total Down Regulation							7	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		3.2
		60.5Hz Capacity		69.5		60.5Hz Output		30.6

Table O-116. Unit Commitment and Dispatch 2021 QV Analysis

Table O-116 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit Commitment Order	Unit Ratings		DR - QV MVAR Capability Thu 8/19/2021 Hour 16		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
Kahului 3	7.1	0.0	1.5	5.7	1.5
Kahului 4	9.4	0.0	1.5	7.9	1.5
Maalaea 14	4.1	0.0	2.6	1.5	2.6
Maalaea 15	2.9	0.0	1.8	1.1	1.8
Maalaea 16	4.1	0.0			
Maalaea 17	15.0	0.0			
Maalaea 18	12.0	0.0			
Maalaea 19	15.0	0.0			
Maalaea 10	9.4	0.0			
Maalaea 12	9.4	0.0			
Maalaea13	9.4	0.0			
Maalaea 11	2.0	0.0			
Maalaea 4	4.2	0.0			
Maalaea 6	4.2	0.0			
Maalaea 9	4.2	0.0			
Maalaea 8	4.2	0.0			
Maalaea 5	4.2	0.0			
Maalaea 1	1.9	0.0			
Maalaea 3	1.9	0.0			
Maalaea 2	1.9	0.0			
Maalaea X2	1.9	0.0			
Maalaea X1	1.9	0.0			
Maalaea 7	4.2	0.0			
Kahului 1	3.0	0.0			
Kahului 2	3.0	0.0			
Sync Condenser 1	30.0	-30	15.8	14.2	45.8
Sync Condenser 1 - 23 k	16.0	-16.0	5.3	10.7	21.3
Total Wind	60.7	-6.7			
-KWP	14.5	-0.2	1.2	13.3	1.5
-Auwahi	6.5	-6.5	0.0	6.5	6.5
-KWPII	10.2	0.0	0.0	10.2	0.0
-New Wind 1	9.9	0.0	0.5	9.4	0.5
-New Wind 2	9.9	0.0	0.4	9.4	0.4
-New Wind 3	9.9	0.0	0.0	9.9	0.0
Total Utility PV	26.3	0.0			
-Utility PV1	6.6	0.0			
-Utility PV2	6.6	0.0			
-Utility PV3	6.6	0.0			
-Utility PV4	6.6	0.0			
DG-PV	0.0	0.0			
DER Grid Ex					
Total Thermal MVAR Generation			28.4		
Total Renewable MVAR Generation			2.1		
Total Cap Bank MVAR			53.0		
Charging MVAR			5.6		
Total MVAR Supply			89.2		
Total MVAR Load			59.8		
Total MVAR Losses			29.3		
Excess MVAR Generation			0.1		
Total MVAR Supply Capability				100	
Total MVAR Absorb Capability					74.4

Table O-117. MVAR Capability 2021 QV Analysis

Table O-117 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
102	Maalaea-Kihei
104	Maalaea-Waiinu
113	Wailea-Auwahi 69 kV
114	Wailea-Kihei 69 kV

Table O-118. N-1 Contingencies 2021 QV Analysis

Table O-118 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

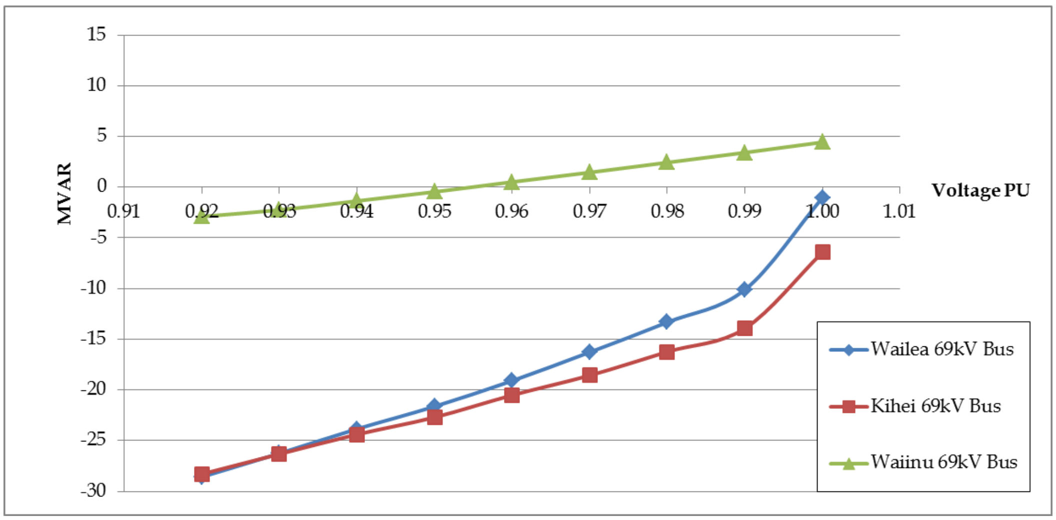

Figure O-266. QV Curves 2021

Figure O-266 shows the QV curves for the Kihei, Waiinu, and Wailea busses for the worst-case N-1 contingency event. The system has sufficient reactive power capacity for the worst-case N-1 contingency.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																	
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
25	Wailea 69 kV Bus	114	-1	113	-10	114	-13	114	-16	114	-19	114	-22	114	-24	114	-26	114	-29
35	Kihei 69 kV Bus	102	-6	102	-14	102	-16	102	-19	102	-21	102	-23	102	-24	102	-26	102	-28
636	Waiinu 69 kV Bus	104	4	104	3	104	2	104	1	104	1	104	0	104	-1	104	-2	104	-3

Table O-119. Summary of Results 2021 QV Analysis

Table O-119 shows the results of the QV analysis for 2019. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

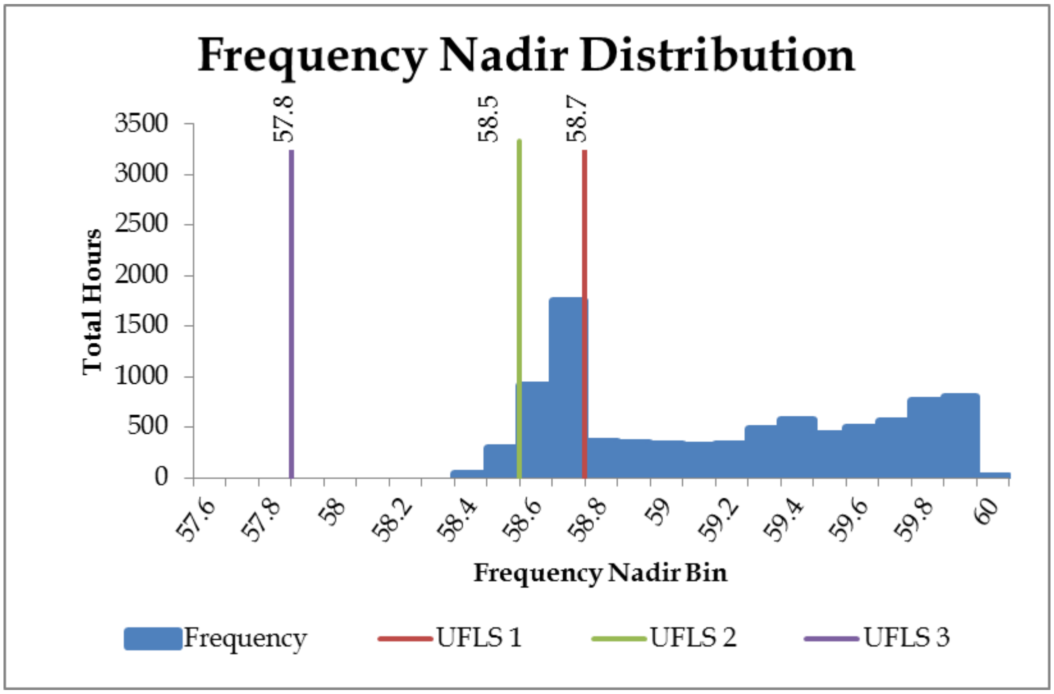

Figure O-267. Frequency Nadir Histogram for 2021

Figure O-267 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 288 hours was 1:00 PM on Thursday, November 25. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 37 hours was 3:00 AM on Thursday, November 25. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

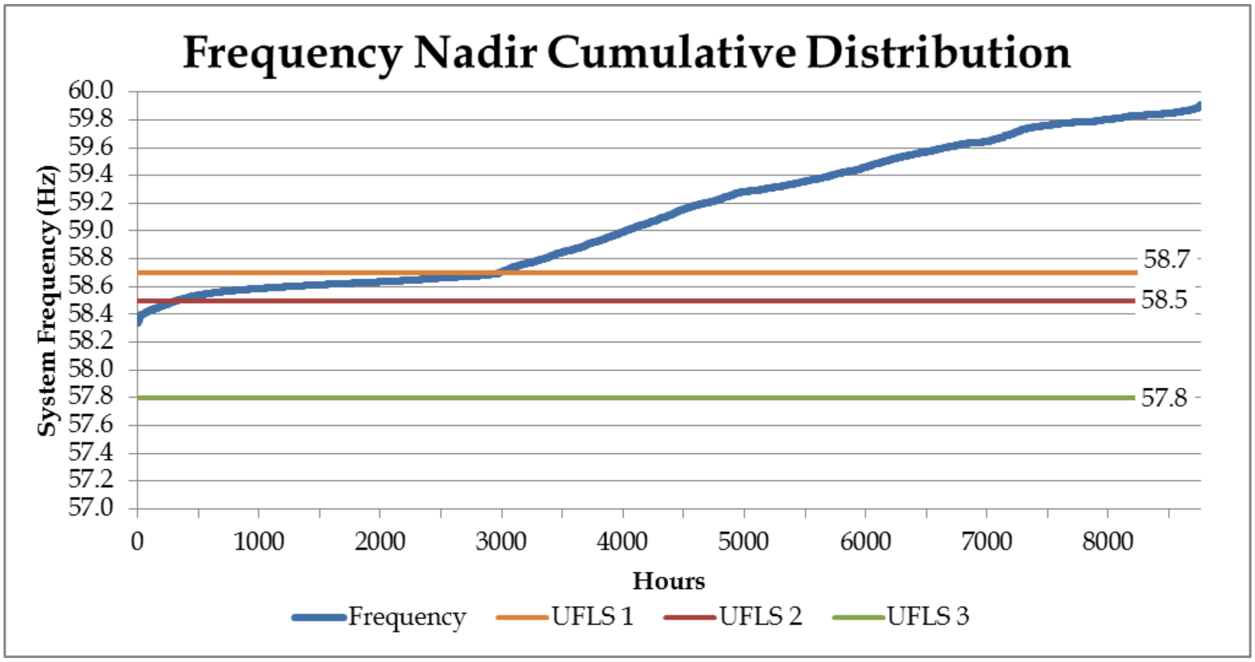

Figure O-268. Frequency Nadir Duration Curve 2021

Figure O-268 shows the frequency nadir duration curve for the resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 325 hours of the year.

Unit	Unit Ratings					DR- KWP I Trip Typical Thu 11/25/2021 Hour 13			DR - KWP I Trip Boundary Thu 11/25/2021 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88						
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	8.9	12.2	3.0	8.9	12.2	3.0
Maalaea 15	13.0	3.0	2.46	18.5	46	7.4	5.6	4.4	7.4	5.6	4.4
Maalaea 16	21.1	5.9	2.02	26.8	54	8.8	12.3	2.9	8.8	12.3	2.9
Maalaea 17	21.1	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	21.1	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalae13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	5.0	0.0	2.62	6.3	16						
Kahului 2	5.0	0.0	2.62	6.3	16						
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*			*Synchronous Condenser*	
Total Wind	162					68			74		
-KWP	30	0				30			30		
-Auwahi	21	0									
-KWPII	21	0				21			21		
-New Wind 1	30	0				6			8		
-New Wind 2	30	0				6			8		
-New Wind 3	30	0				6			8		
Total Utility PV	80					0			0		
-Utility PV1	20	0									
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
Station PV	8	0				5					
DGPV	128	0				74					
Total System MVA							134			134	
Total Kinetic Energy							292			292	
Total Load							177			103	
Total Thermal Generation							28			28	
Total Renewable Generation							147			74	
Total Generation							175			102	
Excess Generation							-2			-1	
Regulation Requirement							0			0	
Total Up Regulation							39			39	
Total Down Regulation							10			10	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		3.2	59.3Hz Output		
	60.5Hz Capacity			69.5		60.5Hz Output		30.6	60.5Hz Output		

Table O-120. Unit Commitment and Dispatch 2021

Table O-120 shows the unit commitment and dispatch for the typical hour (11/25/21, 1:00 PM) and boundary hour (11/25/01, 3:00 AM).

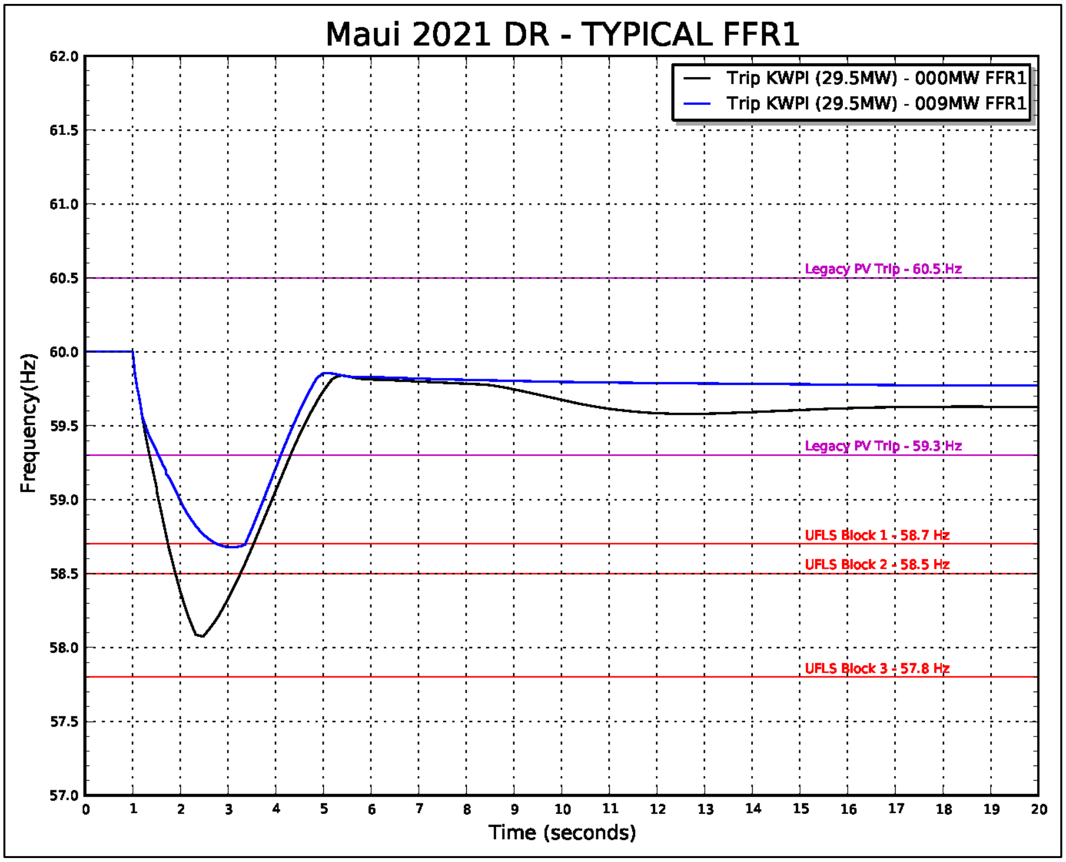

Figure O-269. Frequency Response Profile for FFR1 Typical Hour

Figure O-269 shows the frequency response profile for a KWP 1 trip at 29.5 MW for a typical hour. System kinetic energy is 292 MW-sec and the capacity of legacy PV that will disconnect from the system is 3.2 MW. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

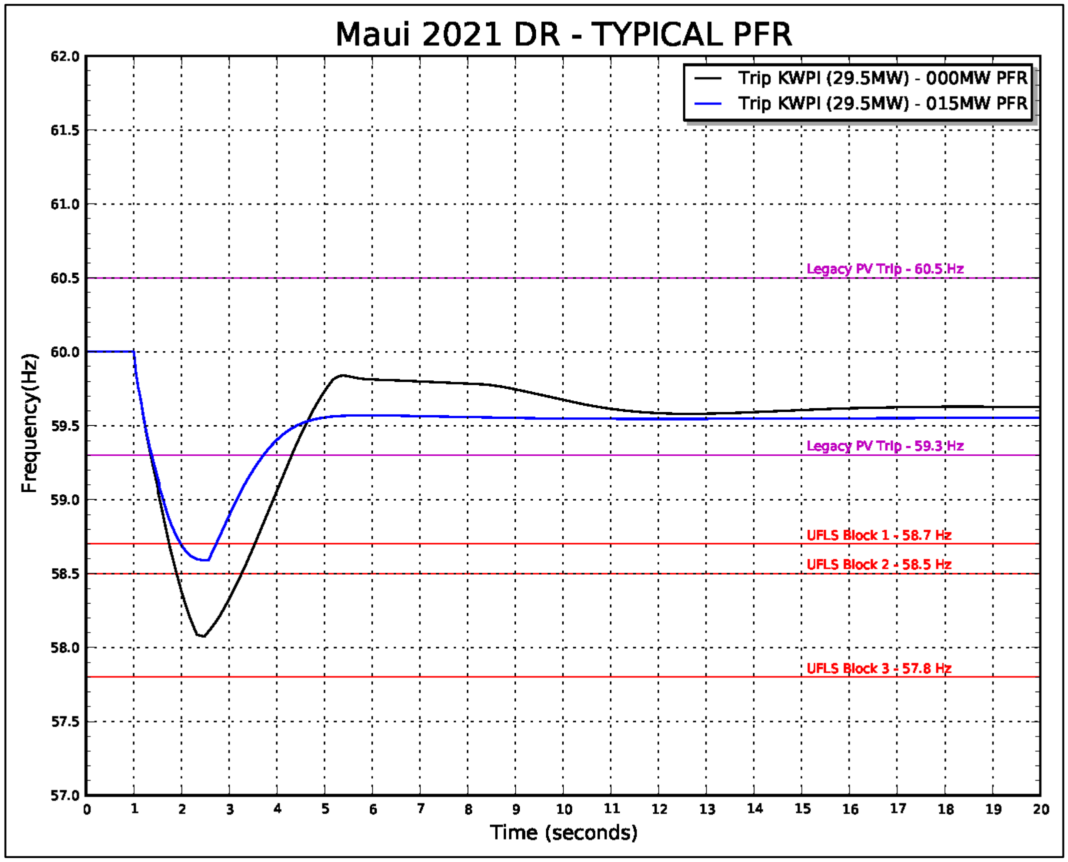

Figure O-270. Frequency Response Profile for PFR Typical Hour

Figure O-270 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 15 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

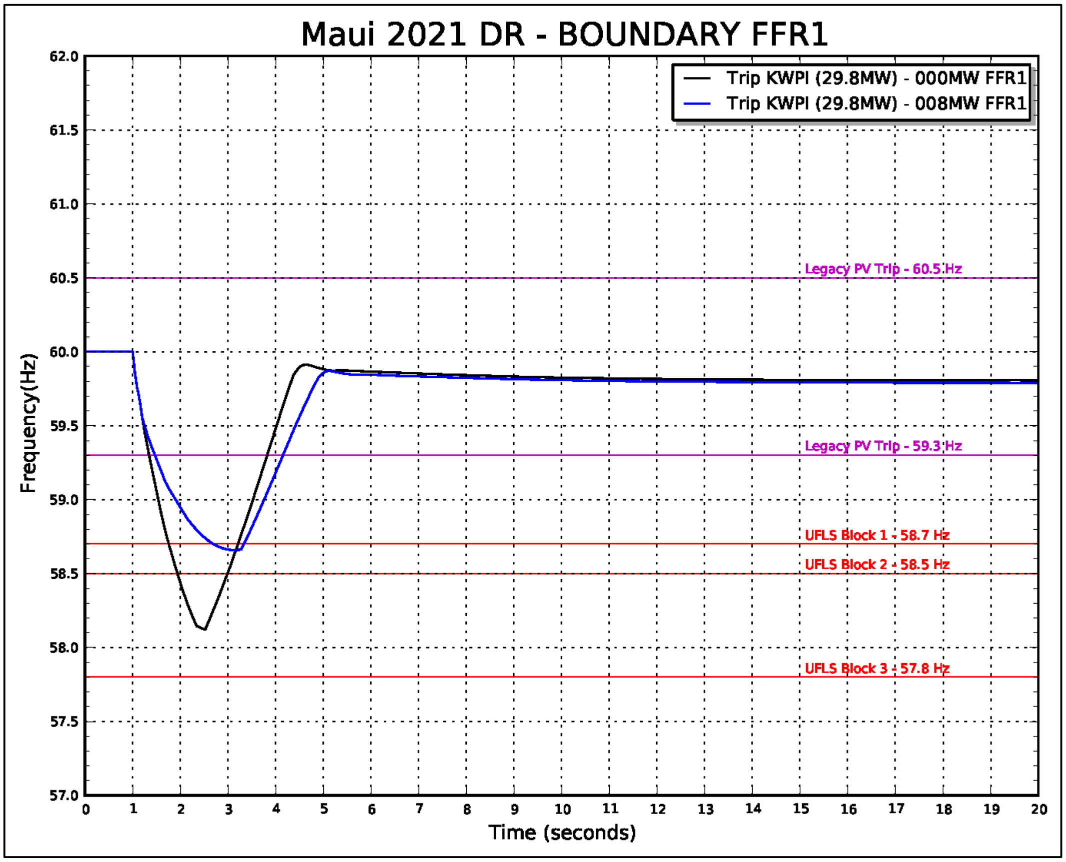

Figure O-271. Frequency Response Profile for FFR1 Boundary Hour

Figure O-271 shows the frequency response profile for a KWP 1 trip at 29.8 MW for a boundary hour. System kinetic energy is 292 MW-sec. With no FFR, the frequency nadir breaches 58.1 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

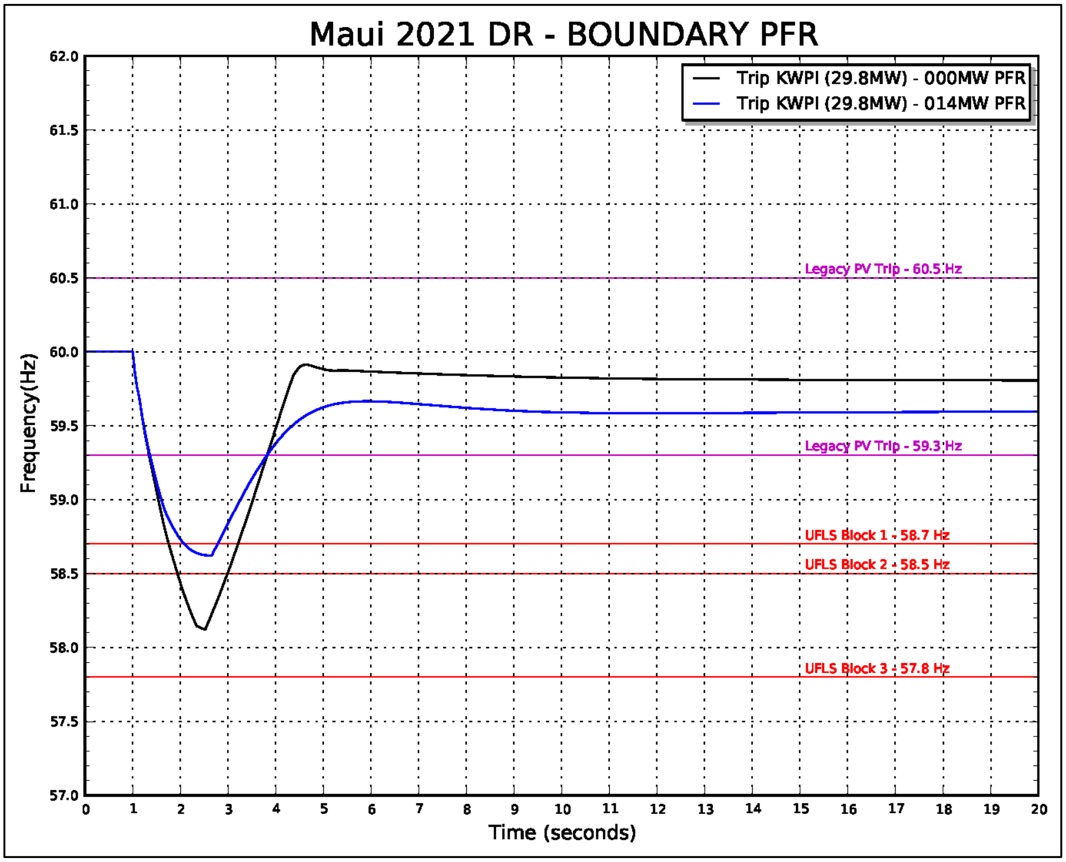

Figure O-272. Frequency Response Profile for PFR Boundary Hour

Figure O-272 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 39 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Simulations were performed for normally cleared faults on a production simulation hour with high DG-PV generation. Sensitivity analyses were performed to 1) stabilize the system for faults that resulted in instability or system collapse; and 2) to bring the system into compliance with the requirements of TPL-001.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 30 cycles depending on the location of the fault.

Unit	Unit Ratings					DR - Fault Sat 5/15/2021 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Kahului 3	11.5	3.0	6.53	13.5	88	6.1	5.4	3.1
Kahului 4	11.5	3.0	3.48	15.6	54	3.0	8.5	0.0
Maalaea 14	21.1	5.9	2.02	26.8	58	9.4	11.8	3.4
Maalaea 15	13.0	3.0	2.46	18.5	46	3.7	9.3	0.7
Maalaea 16	21.1	5.9	2.02	26.8	54			
Maalaea 17	21.1	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	21.1	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalae13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16	1.9	3.7	0.0
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16	5.5	0.0	3.6
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	5.0	0.0	2.62	6.3	16			
Kahului 2	5.0	0.0	2.62	6.3	16			
Sync Condenser 1	0.0	0.0	1.74	30.0	52	*Synchronous Condenser*		
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28	*Synchronous Condenser*		
Total Wind	162					24		
-KWP	30	0						
-Auwahi	21	0						
-KWPII	21	0				21		
-New Wind 1	30	0				1		
-New Wind 2	30	0				1		
-New Wind 3	30	0				1		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
Station PV	8	0				6		
DGPV	128	0				108		
Total System MVA						134		
Total Kinetic Energy						358		
Total Load						167		
Total Thermal Generation						30		
Total Renewable Generation						138		
Total Generation						167		
Excess Generation						0		
Regulation Requirement						0		
Total Up Regulation						39		
Total Down Regulation						11		
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		5.2
	60.5Hz Capacity			69.5		60.5Hz Output		50.0

Table O-121. Unit Commitment and Dispatch Fault Analysis 2021

Table O-121 shows the unit commitment and dispatch for the 69 kV fault analysis (5/15/21, 12:00 PM). Inverter-based generation is 108 MW.

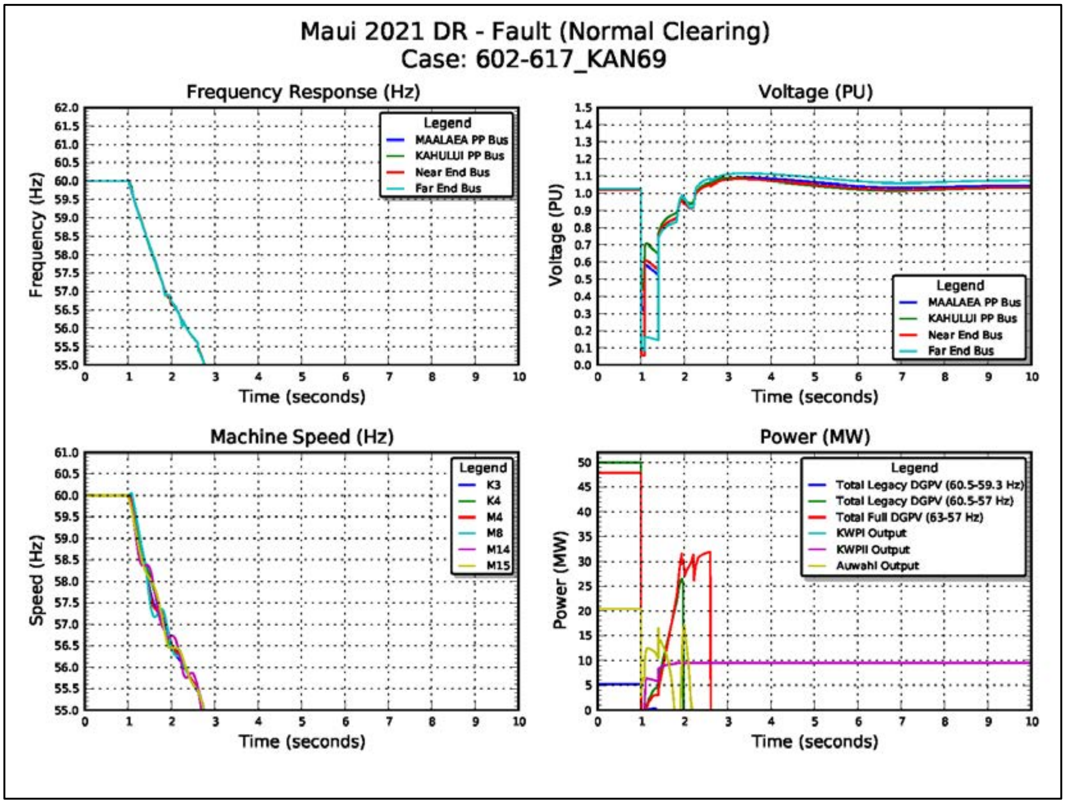

Figure O-273. System Performance for Normally Cleared Fault

Figure O-273 shows the system performance for a normally cleared fault at the Kanaha end of the Kanaha-Pukalani circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 108 MW from inverter-based generation momentarily drops to zero, driving system frequency below 55.0 Hz and system collapse.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to prevent system collapse and bring the system into compliance with TPL-001.

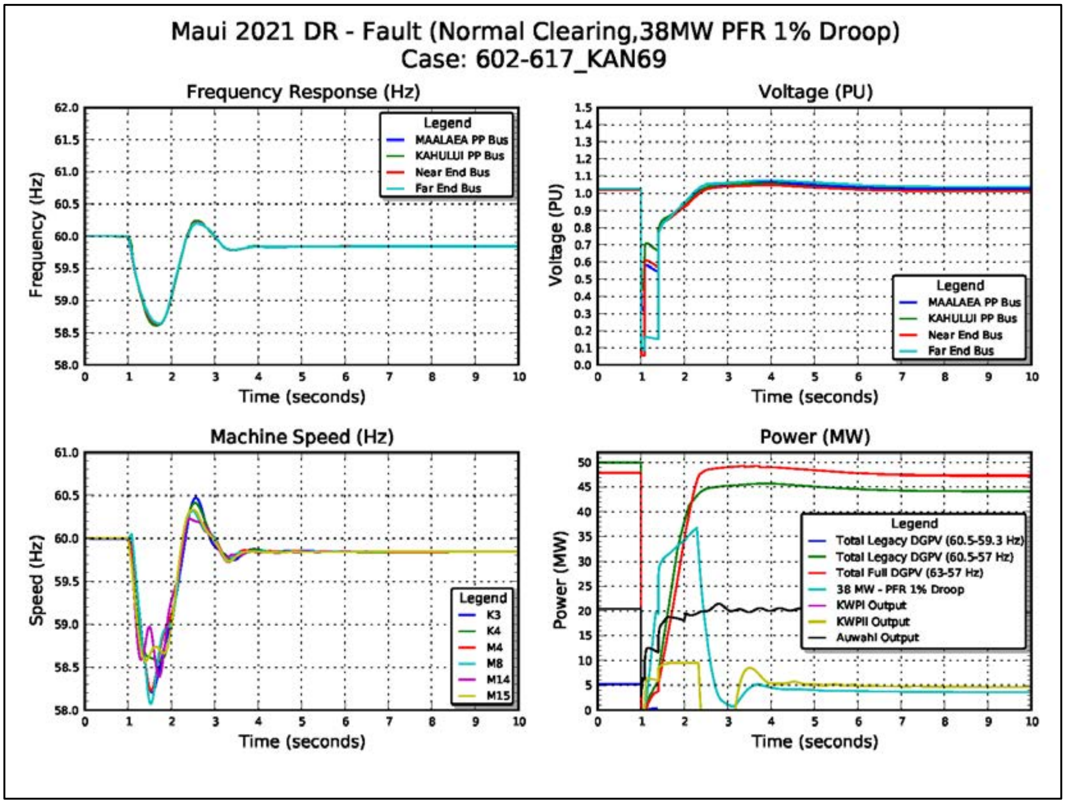

Figure O-274. Normally Cleared Fault Sensitivity 38 MW PFR

Figure O-274 shows system performance with the addition of 38 MW PFR at 1% droop response. For the purpose of this analysis, a 38 MW BESS was located at Ma‘alaea.

The plot at the bottom right shows the frequency response from DG-PV, the three wind plants, and the 38 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and one block of UFLS brings the system into compliance with TPL-001.

Maui 2021 DR Fault Analysis				
Line	3-phase Fault Near	System Status		
		Normal Clearing	Mitigation 38MW PFR 1% Droop	Mitigation: 5Cycle Clearing
Wailuku-Waiinu 23kV	Wailuku	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Kahului Sub-Kahana 23kV	Kahului Sub	Stable	Stable	Stable
	Kanaha	Stable	Stable	Stable
Kahului Sub-Waiinu 23kV	Kahului Sub	Stable	Stable	Stable
	Waiinu	Stable	Stable	Stable
Wailea-Kihei 69kV	Wailea	Unstable	Stable	Stable
	Kihei	Unstable	Stable	Stable
Lahaina-Lahainaluna 69kV	Lahaina	Unstable	Stable	Stable
	Lahainaluna	Unstable	Stable	Stable
MPP-Kihei 69kV	MPP	Stable	Stable	Stable
	Kihei	Stable	Stable	Stable
MPP-Waiinu 69kV	MPP	Stable	Stable	Stable
	Waiinu	Unstable	Unstable	Stable
MPP-Puunene 69kV	MPP	Unstable	Stable	Stable
	Puunene	Unstable	Unstable	Stable
MPP-KWPII 69kV	MPP	Stable	Stable	Stable
	KWPII	Stable	Stable	Stable
MPP-KWP 69kV	MPP	Stable	Stable	Stable
	KWP	Stable	Stable	Stable
MPP-Lahainaluna 69kV	MPP	Stable	Stable	Stable
	Lahainaluna	Stable	Stable	Stable
MPP-Kula AG 69kV	MPP	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
Kealahou-Kula 69kV	Kealahou	Stable	Stable	Stable
	Kula	Unstable	Stable	Stable
Kealahou-Kula AG 69kV	Kealahou	Unstable	Stable	Stable
	Kula AG	Unstable	Stable	Stable
KPP-Kanaha FDR1 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR1	Unstable	Stable	Stable
KPP-Kanaha FDR2 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR2	Unstable	Stable	Stable
KPP-Kanaha FDR3 23kV	KPP	Unstable	Stable	Stable
	Kanaha FDR3	Unstable	Stable	Stable
KPP-Wailuku 23kV	KPP	Stable	Stable	Stable
	Wailuku	Stable	Stable	Stable
Kanaha-Puunene 23kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kanaha-Pukalani 69kV	Kanaha	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable
Kanaha-Puunene 69kV	Kanaha	Stable	Stable	Stable
	Puunene	Stable	Stable	Stable
Kula-Pukalani 69kV	Kula	Unstable	Stable	Stable
	Pukalani	Unstable	Stable	Stable

Table O-122. Summary of Results Fault Analysis 2021

Table O-122 shows the results of the 69 kV fault analysis with 38 MW of PFR. Only the Ma‘alaea-Waiinu and Ma‘alaea–Pu‘unene circuit faults could not be stabilized. Simulations were performed for 5-cycle clearing times to simulate dual pilot or dual differential relay schemes. Further analysis is required to determine an optimal strategy to ensure system stability and bring the system into compliance with TPL-001.

2023

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

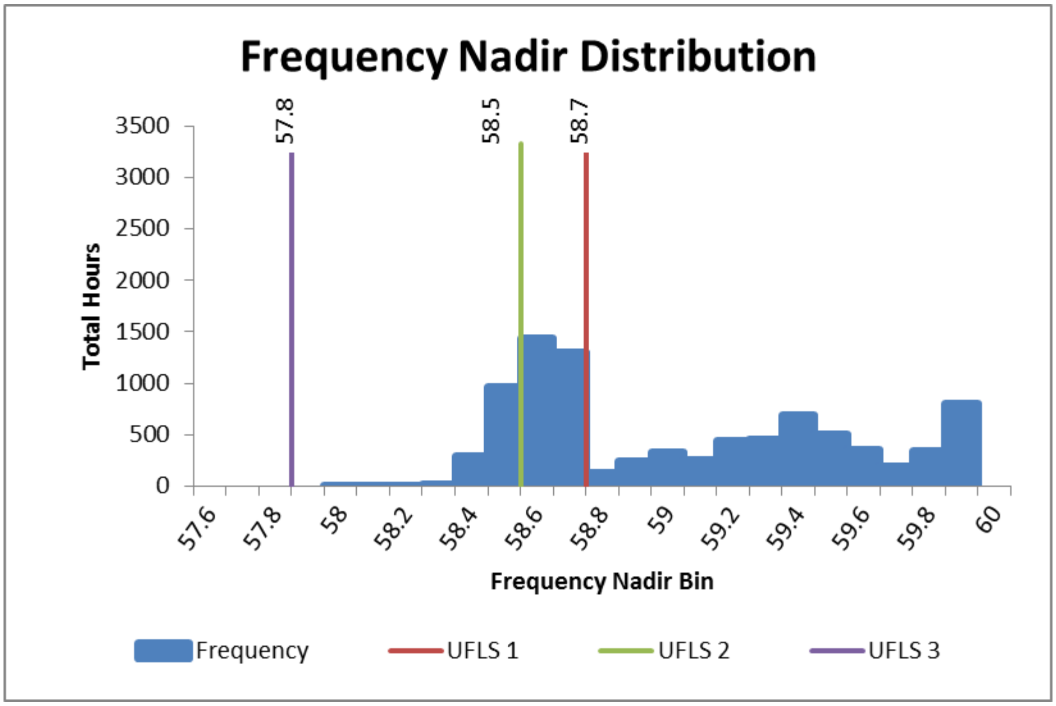

Figure O-275. Frequency Nadir Histogram for 2023

Figure O-275 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 959 hours was 1:00 PM on Monday, April 10. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 24 hours was 1:00 AM on Sunday, July 23. The frequency nadir range for the boundary hour is 58.2 – 58.3 Hz that requires two blocks of UFLS to stabilize system frequency.

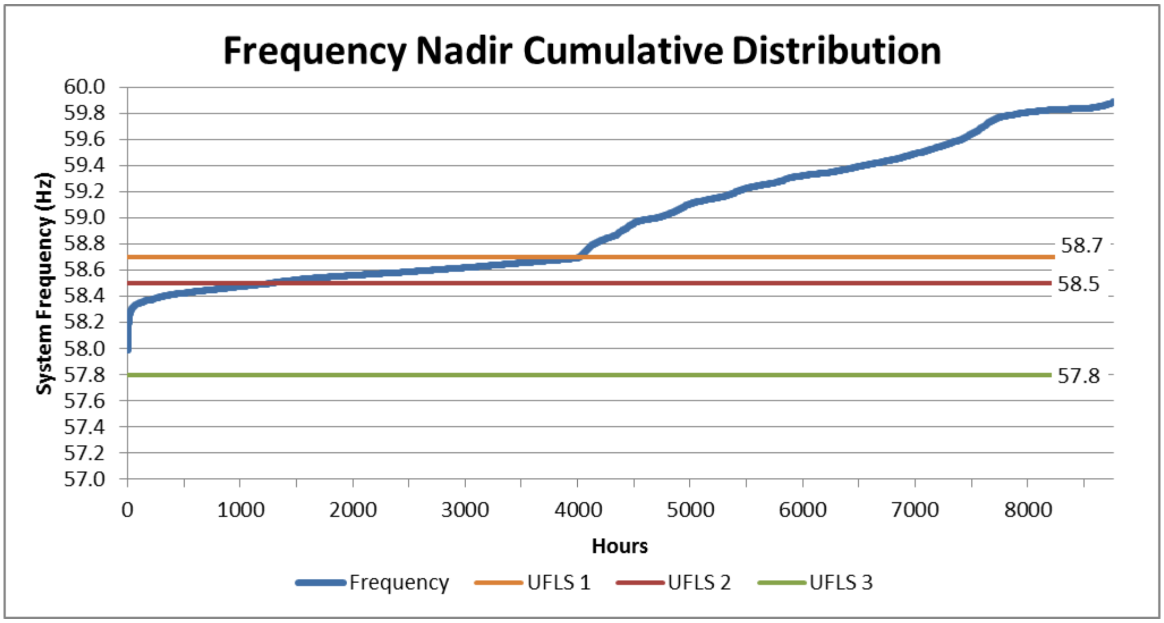

Figure O-276. Frequency Nadir Duration Curve 2023

Figure O-276 shows the frequency nadir duration curve for the resource plan in 2023. The system is at risk of exceeding the UFLS requirements of TPL-001 for 1284 hours of the year.

Unit	Unit Ratings					DR - KWP 1 Trip Typical Mon 4/10/2023 Hour 12			DR - KWP 1 Trip Boundary Sun 7/23/2023 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87	8.0	12.0	2.0			
Maalaea 14	20.0	5.9	2.02	26.8	54						
Maalaea 15	13.0	5.0	2.46	18.5	46						
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	0.0	0.0	2.62	6.3	16		*Retired*			*Retired*	
Kahului 2	0.0	0.0	2.62	6.3	16		*Retired*			*Retired*	
Kahului 4	0.0	0.0	1.74	15.6	27		*Retired*			*Retired*	
Kahului 3	0.0	0.0	3.27	13.5	44		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 3	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*			*Synchronous Condenser*	
Total Wind	162					93			98		
-KWP	30	0				30			29		
-Auwahi	21	0									
-KWPII	21	0				21			20		
-New Wind 1	30	0				14			16		
-New Wind 2	30	0				14			16		
-New Wind 3	30	0				14			16		
Total Utility PV	80					6			6		
-Utility PV1	20	0				6			6		
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	131	0				93			91		
DER Grid Ex	10	0				0			0		
Total System MVA							145			120	
Total Kinetic Energy							316			229	
Total Load							200			196	
Total Thermal Generation							8			0	
Total Renewable Generation							192			195	
Total Generation							200			195	
Excess Generation							0			-1	
Regulation Requirement							0			0	
Total Up Regulation							12			0	
Total Down Regulation							2			0	
Legacy DG-PV	59.3Hz Capacity			7.2		59.3Hz Output		4.5	59.3Hz Output		4.4
	60.5Hz Capacity			69.5		60.5Hz Output		43.8	60.5Hz Output		46.8

Table O-123. Unit Commitment and Dispatch 2023

Table O-123 shows the unit commitment and dispatch for the typical hour (4/10/23, 12:00 PM) and boundary hour (7/23/23, 1:00 PM).

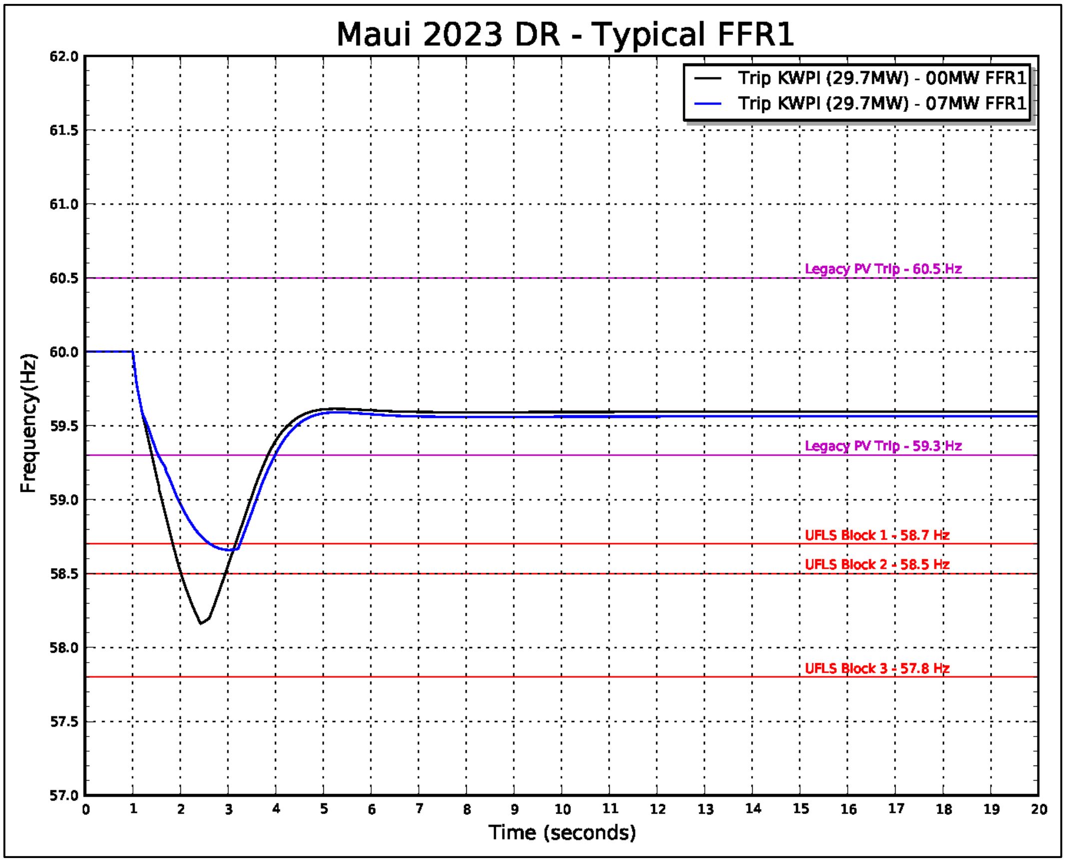

Figure O-277. Frequency Response Profile for FFR1 Typical Hour

Figure O-277 shows the frequency response profile for a KWP 1 trip at 29.7 MW for a typical hour. System kinetic energy is 316 MW-sec and the capacity of legacy PV that will disconnect from the system is 4.5 MW. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7MW.

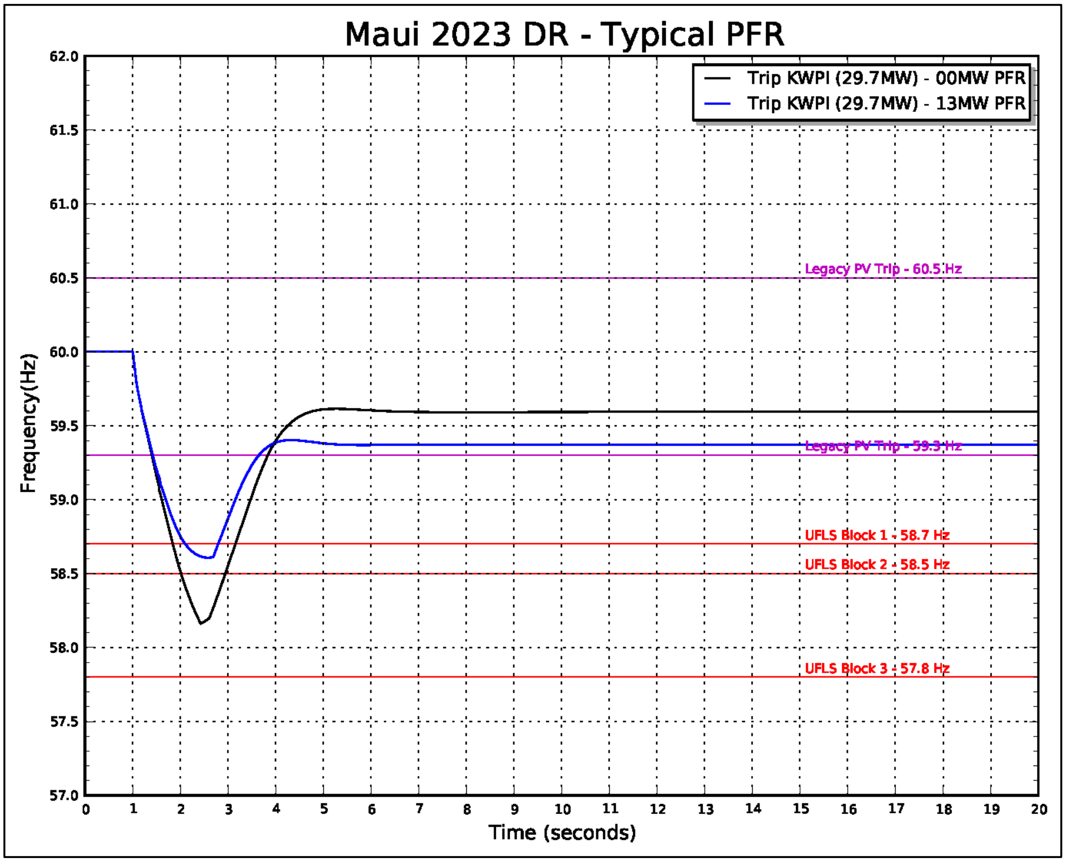

Figure O-278. Frequency Response Profile for PFR Typical Hour

Figure O-278 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 13 MW.

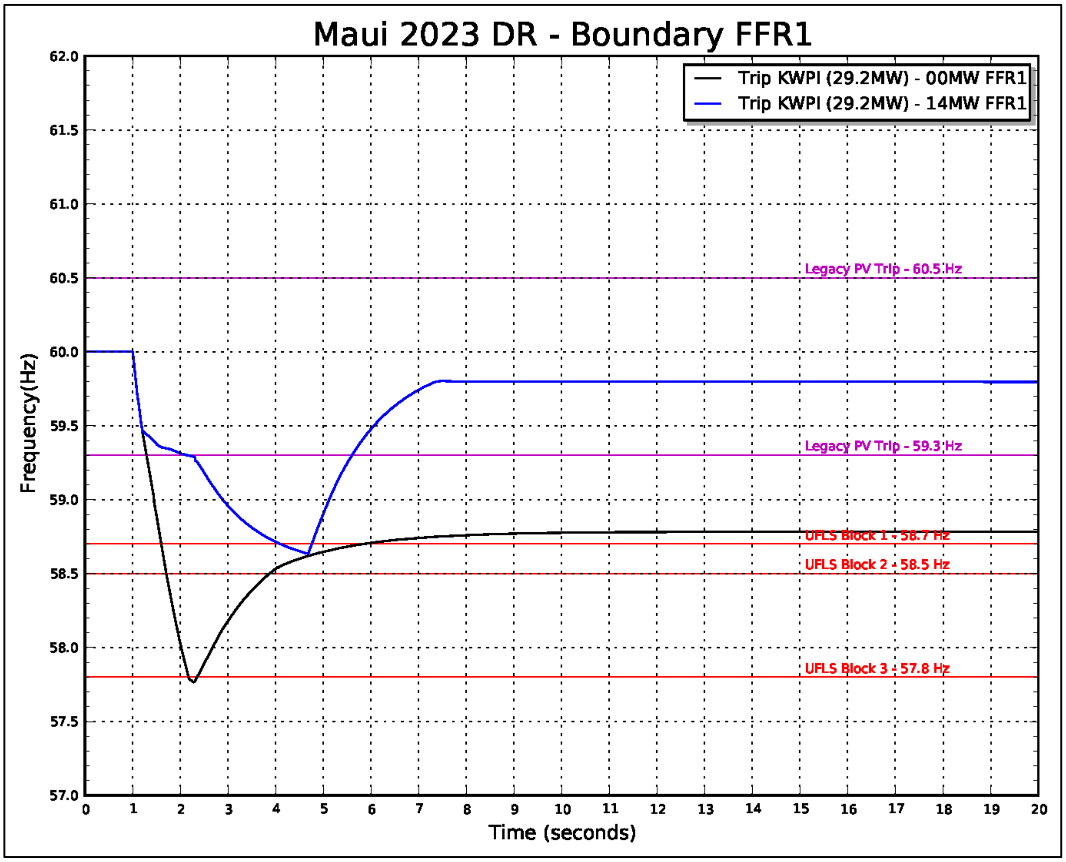

Figure O-279. Frequency Response Profile for FFR1 Boundary Hour

Figure O-279 shows the frequency response profile for a KWP 1 trip at 29.2 MW for a boundary hour. System kinetic energy is 229 MW-sec and the capacity of legacy PV that will disconnect from the system at 59.3 Hz is 4.4 MW. With no FFR, the frequency nadir breaches 57.8 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 14 MW.

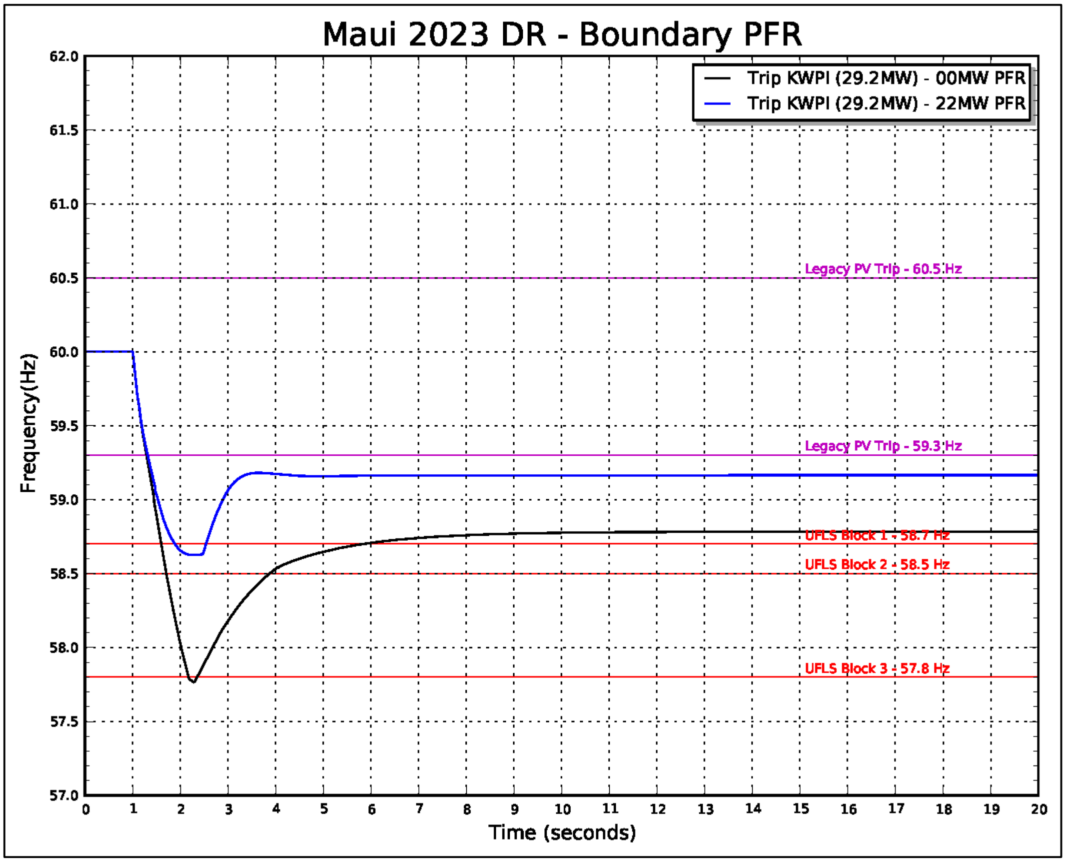

Figure O-280. Frequency Response Profile for PFR Boundary Hour

Figure O-280 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 22 MW.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition.

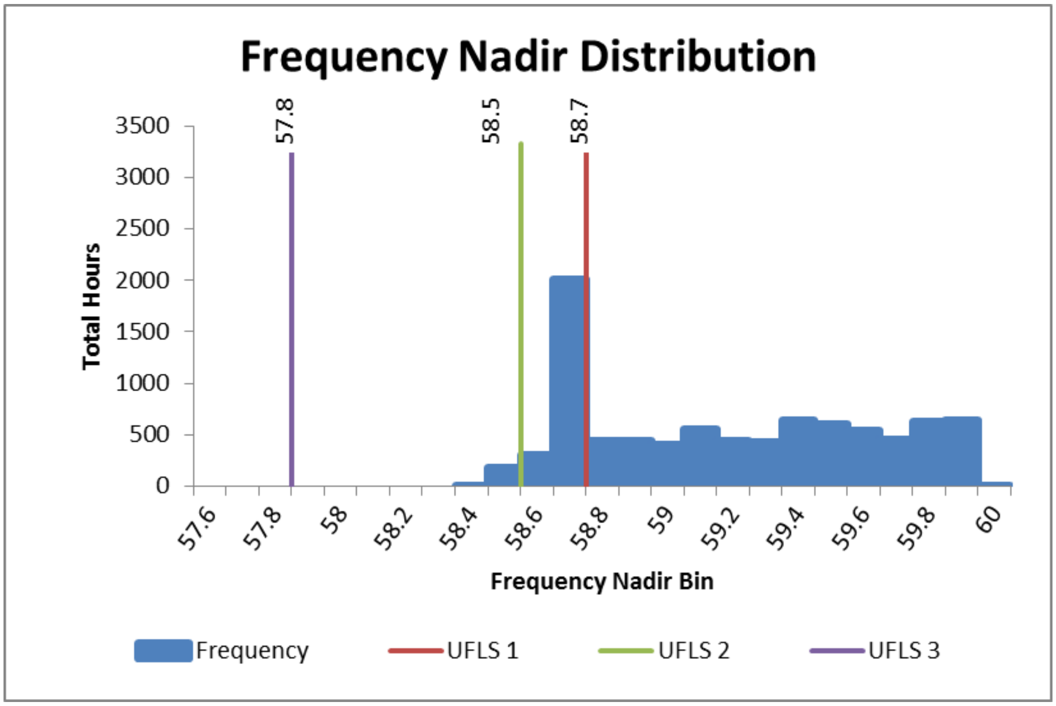

Figure O-281. Frequency Nadir Histogram for 2030

Figure O-281 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The typical hour selected from a maximum distribution of 184 hours was 4:00 AM on Tuesday, March 26. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

The boundary hour selected from a minimum distribution of 4 hours was 3:00 AM on Sunday, March 24. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires two blocks of UFLS to stabilize system frequency.

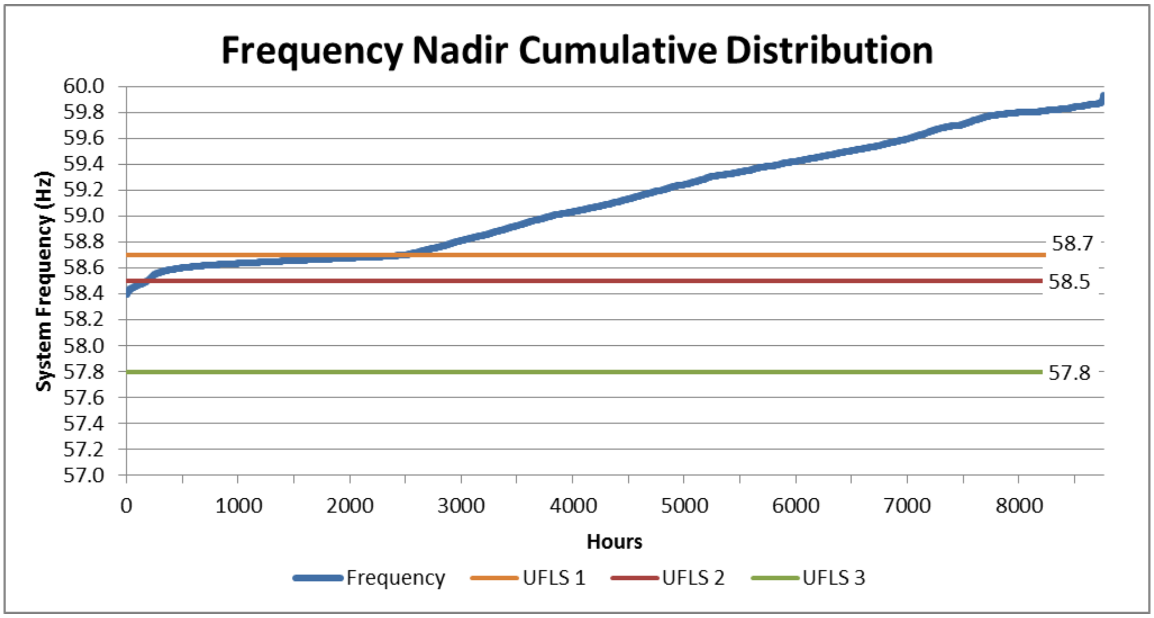

Figure O-282. Frequency Nadir Duration Curve 2030

Figure O-282 shows the frequency nadir duration curve for the resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 188 hours of the year.

Unit	Unit Ratings					DR - KWP 1 Trip Typical Tues 3/26/2030 Hour 4			DR - KWP 1 Trip Boundary Sun 3/24/2030 Hour 2		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87						
Geothermal 1	20.0	5.0	3.48	25.0	87	5.6			5.6		
Geothermal 2	20.0	5.0	3.48	25.0	87	5.6			5.6		
4Hr LS BESS	20.0	0.0			0	20.0					
Maalaea 14	20.0	5.9	2.02	26.8	54						
Maalaea 15	13.0	5.0	2.46	18.5	46						
Maalaea 16	20.0	5.9	2.02	26.8	54						
Maalaea 17	19.5	5.9	2.02	26.8	54						
Maalaea 18	12.8	3.0	2.46	18.5	46						
Maalaea 19	19.5	5.9	2.02	26.8	54						
Maalaea 10	12.3	7.9	3.28	15.6	51						
Maalaea 12	12.3	7.9	3.28	15.6	51						
Maalaea 13	12.3	7.9	3.28	15.6	51						
Maalaea 11	12.3	7.9	3.28	15.6	51						
Maalaea 4	5.5	1.9	2.28	7.0	16						
Maalaea 6	5.5	1.9	2.28	7.0	16						
Maalaea 9	5.5	1.9	2.28	7.0	16						
Maalaea 8	5.5	1.9	2.28	7.0	16						
Maalaea 5	5.5	1.9	2.28	7.0	16						
Maalaea 1	2.5	2.5	0.83	3.4	3						
Maalaea 3	2.5	2.5	0.83	3.4	3						
Maalaea 2	2.5	2.5	0.83	3.4	3						
Maalaea X2	2.5	2.5	0.83	3.4	3						
Maalaea X1	2.5	2.5	0.83	3.4	3						
Maalaea 7	5.5	1.9	2.28	7.0	16						
Kahului 1	0.0	0.0	2.62	6.3	16		*Retired*			*Retired*	
Kahului 2	0.0	0.0	2.62	6.3	16		*Retired*			*Retired*	
Kahului 4	0.0	0.0	1.74	15.6	27		*Retired*			*Retired*	
Kahului 3	0.0	0.0	3.27	13.5	44		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sync Condenser 3	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*			*Synchronous Condenser*	
Sml Sync Condenser 1	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*			*Synchronous Condenser*	
Total Wind	162					64			94		
-KWP	30	0				29			29		
-Auwahi	21	0									
-KWPII	21	0				19			21		
-New Wind 1	30	0				5			15		
-New Wind 2	30	0				5			15		
-New Wind 3	30	0				5			15		
Total Utility PV	80					0			0		
-Utility PV1	20	0									
-Utility PV2	20	0									
-Utility PV3	20	0									
-Utility PV4	20	0									
DG-PV	131	0				0			0		
DER Grid Ex	10	0				6			0		
Total System MVA							170			170	
Total Kinetic Energy							403			403	
Total Load							102			105	
Total Thermal Generation							31			11	
Total Renewable Generation							70			94	
Total Generation							102			105	
Excess Generation							0			0	
Regulation Requirement[1]							0			0	
Total Up Regulation							0			0	
Total Down Regulation							0			0	
Legacy DG-PV		59.3Hz Capacity		7.2		59.3Hz Output		0.0	59.3Hz Output		0.0
		60.5Hz Capacity		69.5		60.5Hz Output		0.0	60.5Hz Output		0.0

Table O-124. Unit Commitment and Dispatch 2030

Table O-124 shows the unit commitment and dispatch for the typical hour (3/26/30, 4:00 AM) and boundary hour (3/24/30, 2:00 AM).

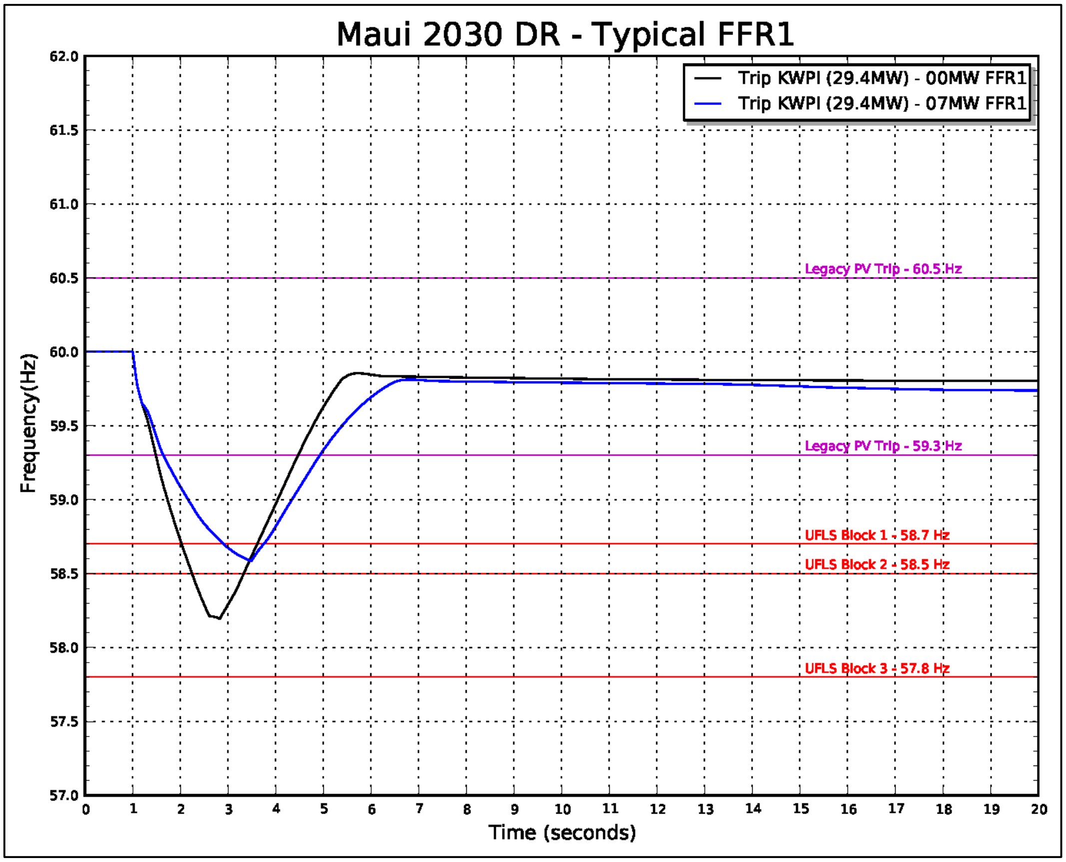

Figure O-283. Frequency Response Profile for FFR1 Typical Hour

Figure O-283 shows the frequency response profile for a KWP 1 trip at 29.4 MW for a typical hour. System kinetic energy is 403 MW-sec. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

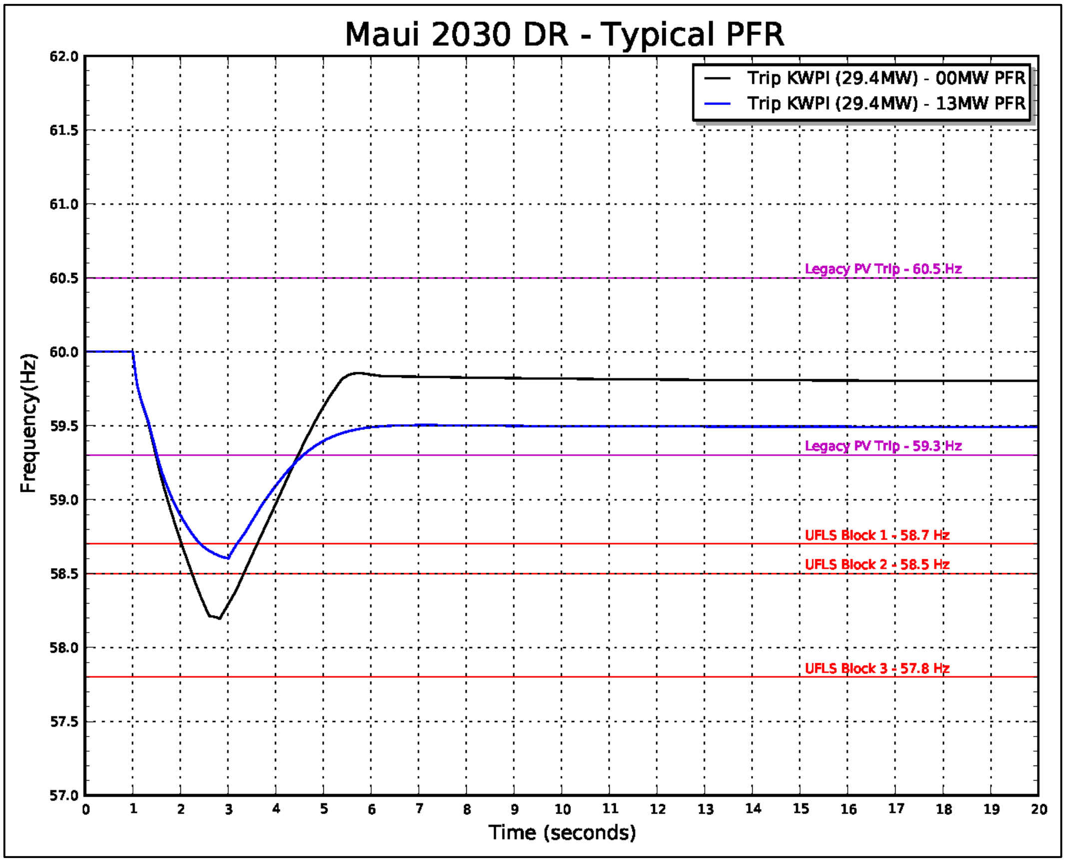

Figure O-284. Frequency Response Profile for PFR Typical Hour

Figure O-284 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 13 MW. This is in addition to the 30 MW of upward regulation from thermal generation.

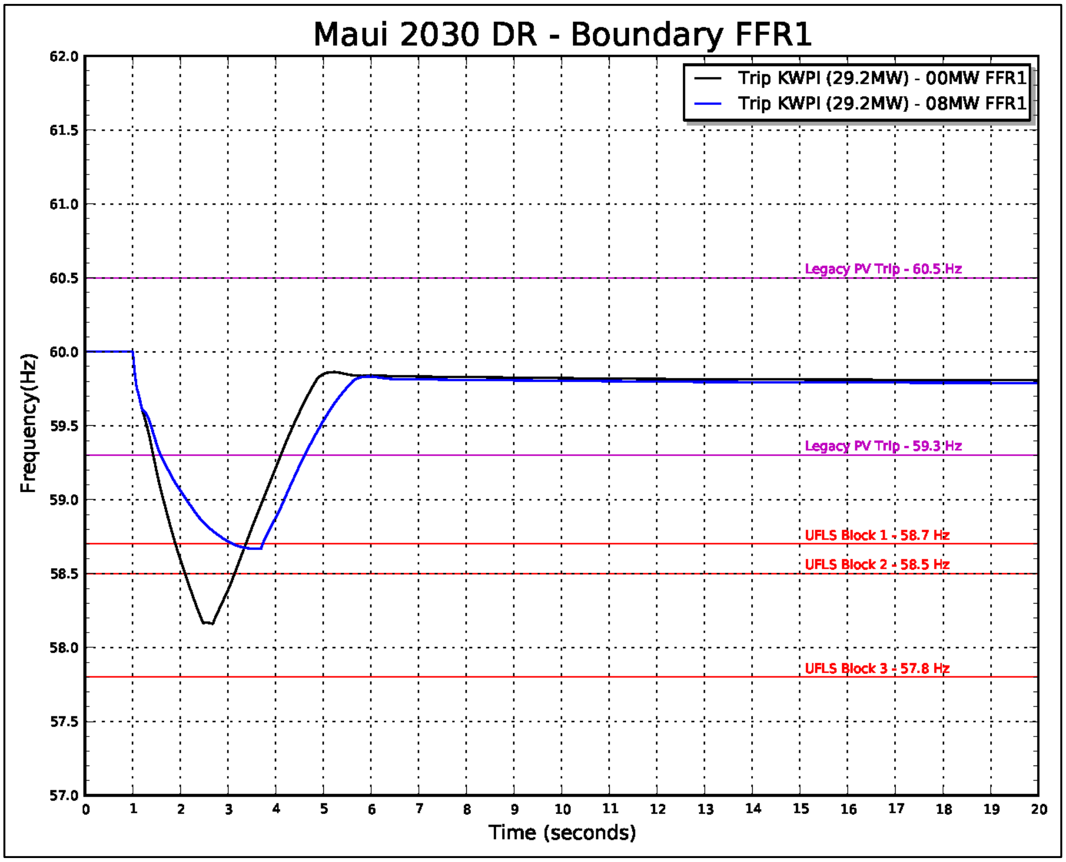

Figure O-285. Frequency Response Profile for FFR1 Boundary Hour

Figure O-285 shows the frequency response profile for a KWP 1 trip at 29.2 MW for a boundary hour. System kinetic energy is 403 MW-sec. With no FFR, the frequency nadir breaches 58.2 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

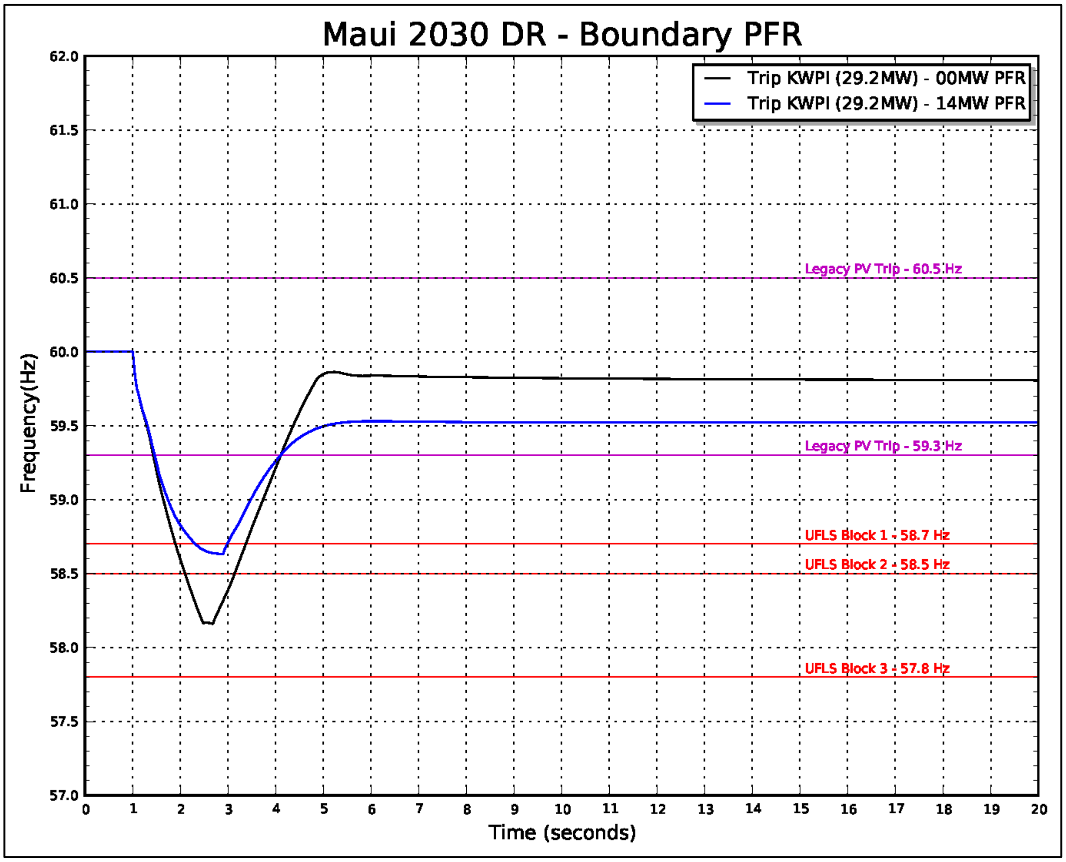

Figure O-286. Frequency Response Profile for PFR Boundary Hour

Figure O-286 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 14 MW. This is in addition to the 39 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production simulation data to represent a boundary condition.

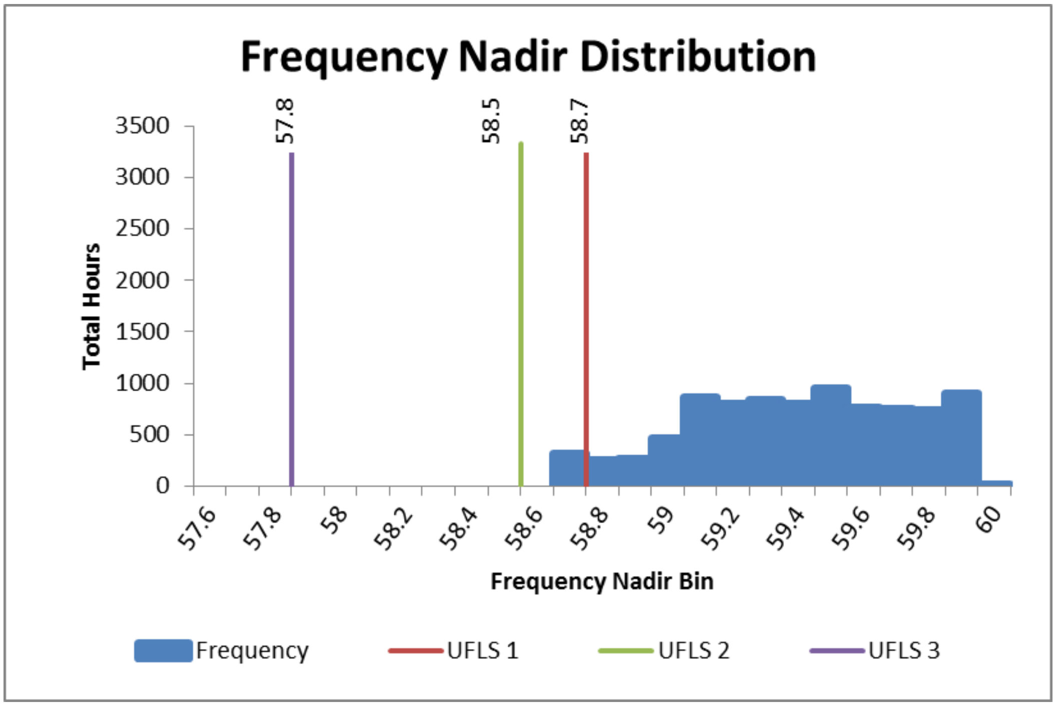

Figure O-287. Frequency Nadir Histogram for 2045

Figure O-287 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a maximum distribution of 323 hours was 8:00 PM on Saturday, July 10. The frequency nadir range for the typical hour is 58.6 – 58.7 Hz that requires one block of UFLS to help stabilize system frequency.

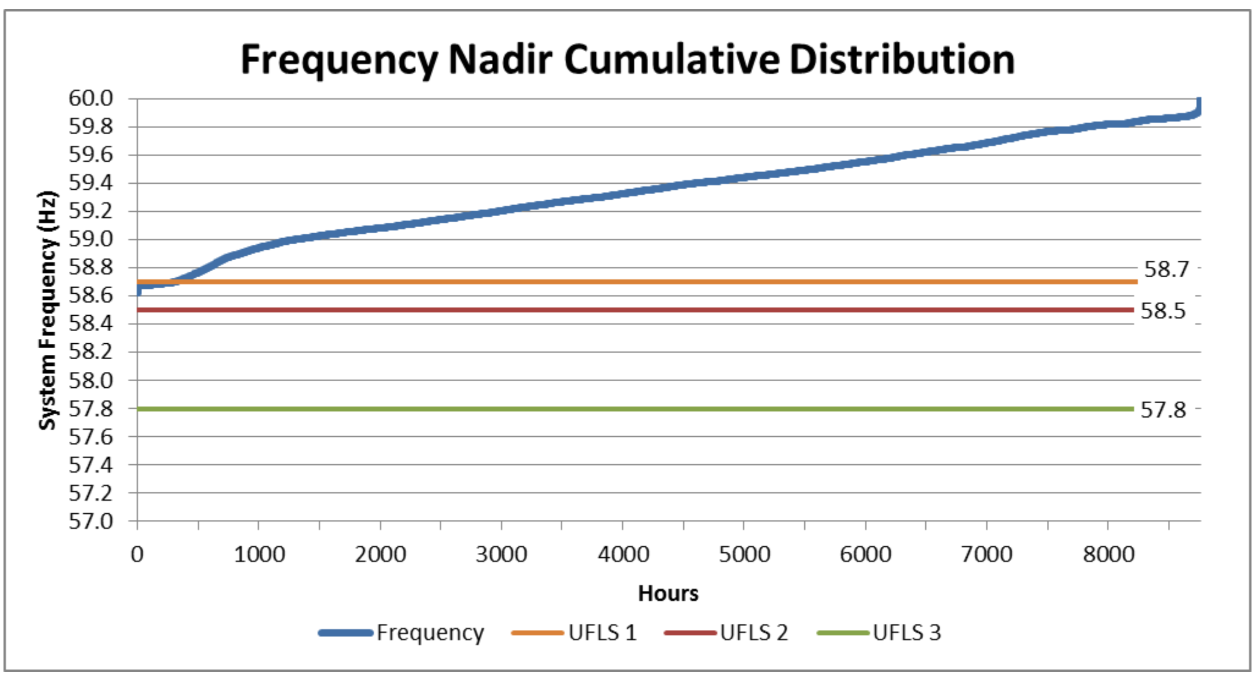

Figure O-288. Frequency Nadir Duration Curve 2045

Figure O-288 shows the frequency nadir duration curve for the resource plan in 2045. The system is at risk of exceeding the UFLS requirements of TPL-001 for 325 hours of the year.

Unit	Unit Ratings					DR - LS BESS Trip Boundary Sat 7/10/2045 Hour 20		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
Biomass 1	20.0	6.0	3.48	25.0	87			
Geothermal 1	20.0	5.0	3.48	25.0	87	16.4		
Geothermal 2	20.0	5.0	3.48	25.0	87	16.4		
6Hr LS BESS	30.0	0.0			0	30.0		
Maalaea 14	20.0	5.9	2.02	26.8	54			
Maalaea 15	13.0	5.0	2.46	18.5	46			
Maalaea 16	20.0	5.9	2.02	26.8	54			
Maalaea 17	19.5	5.9	2.02	26.8	54			
Maalaea 18	12.8	3.0	2.46	18.5	46			
Maalaea 19	19.5	5.9	2.02	26.8	54			
Maalaea 10	12.3	7.9	3.28	15.6	51			
Maalaea 12	12.3	7.9	3.28	15.6	51			
Maalaea 13	12.3	7.9	3.28	15.6	51			
Maalaea 11	12.3	7.9	3.28	15.6	51			
Maalaea 4	5.5	1.9	2.28	7.0	16			
Maalaea 6	5.5	1.9	2.28	7.0	16			
Maalaea 9	5.5	1.9	2.28	7.0	16			
Maalaea 8	5.5	1.9	2.28	7.0	16			
Maalaea 5	5.5	1.9	2.28	7.0	16			
Maalaea 1	2.5	2.5	0.83	3.4	3			
Maalaea 3	2.5	2.5	0.83	3.4	3			
Maalaea 2	2.5	2.5	0.83	3.4	3			
Maalaea X2	2.5	2.5	0.83	3.4	3			
Maalaea X1	2.5	2.5	0.83	3.4	3			
Maalaea 7	5.5	1.9	2.28	7.0	16			
Kahului 1	0.0	0.0	2.62	6.3	16		*Retired*	
Kahului 2	0.0	0.0	2.62	6.3	16		*Retired*	
Kahului 4	0.0	0.0	1.74	15.6	27		*Retired*	
Kahului 3	0.0	0.0	3.27	13.5	44		*Synchronous Condenser*	
Sync Condenser 1	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 2	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 3	0.0	0.0	1.74	30.0	52		*Synchronous Condenser*	
Sync Condenser 1 - 23 kV	0.0	0.0	1.74	16.0	28		*Synchronous Condenser*	
Total Wind	162					119		
-KWP	30	0				21		
-Auwahi	21	0				15		
-KWPII	21	0				19		
-New Wind 1	30	0				21		
-New Wind 2	30	0				22		
-New Wind 3	30	0				22		
Total Utility PV	80					0		
-Utility PV1	20	0						
-Utility PV2	20	0						
-Utility PV3	20	0						
-Utility PV4	20	0						
DG-PV	131	0				0		
DER Grid Ex	10	0				0		
Total System MVA							170	
Total Kinetic Energy							403	
Total Load							182	
Total Thermal Generation							63	
Total Renewable Generation							119	
Total Generation							181	
Excess Generation							0	
Regulation Requirement							0	
Total Up Regulation							0	
Total Down Regulation							0	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0

Table O-125. Unit Commitment and Dispatch 2045

Table O-125 shows the unit commitment and dispatch for the boundary hour (7/10/45, 8:00 PM)

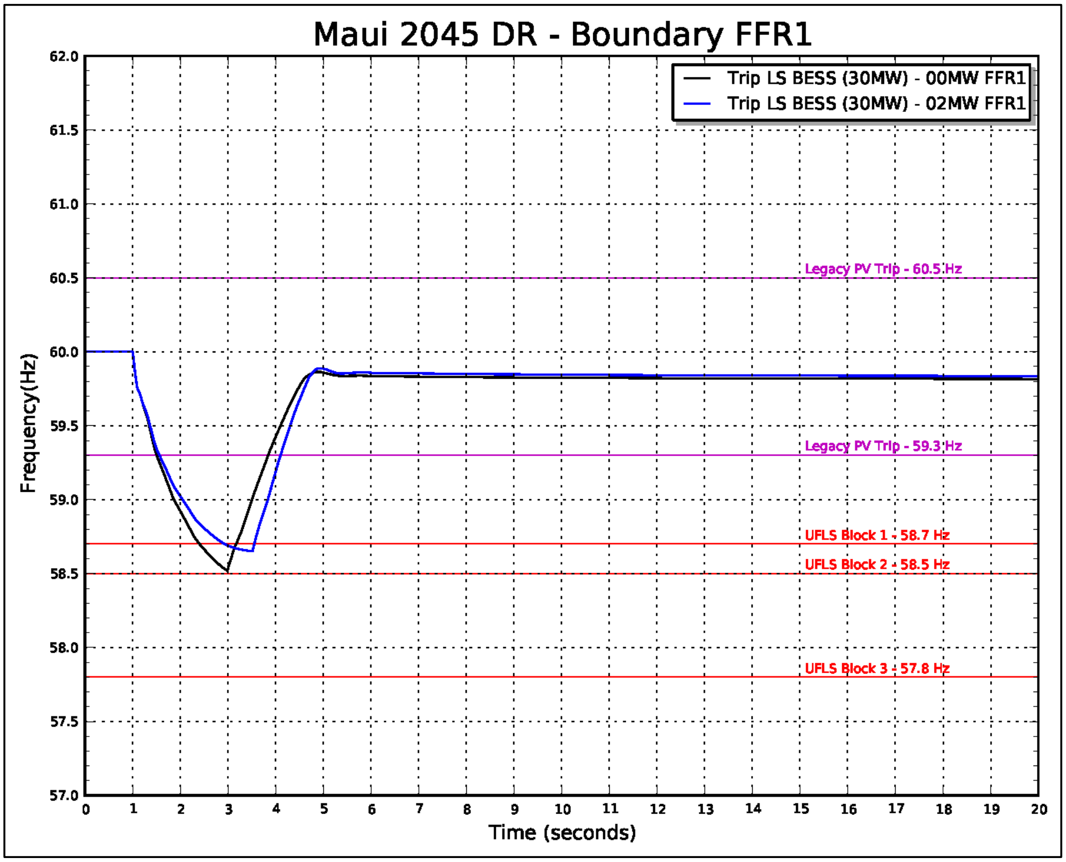

Figure O-289. Frequency Response Profile for FFR1 Boundary Hour

Figure O-289 shows the frequency response profile for a load-shifting BESS trip at 30 MW for a boundary hour . System kinetic energy is 403 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 2 MW.

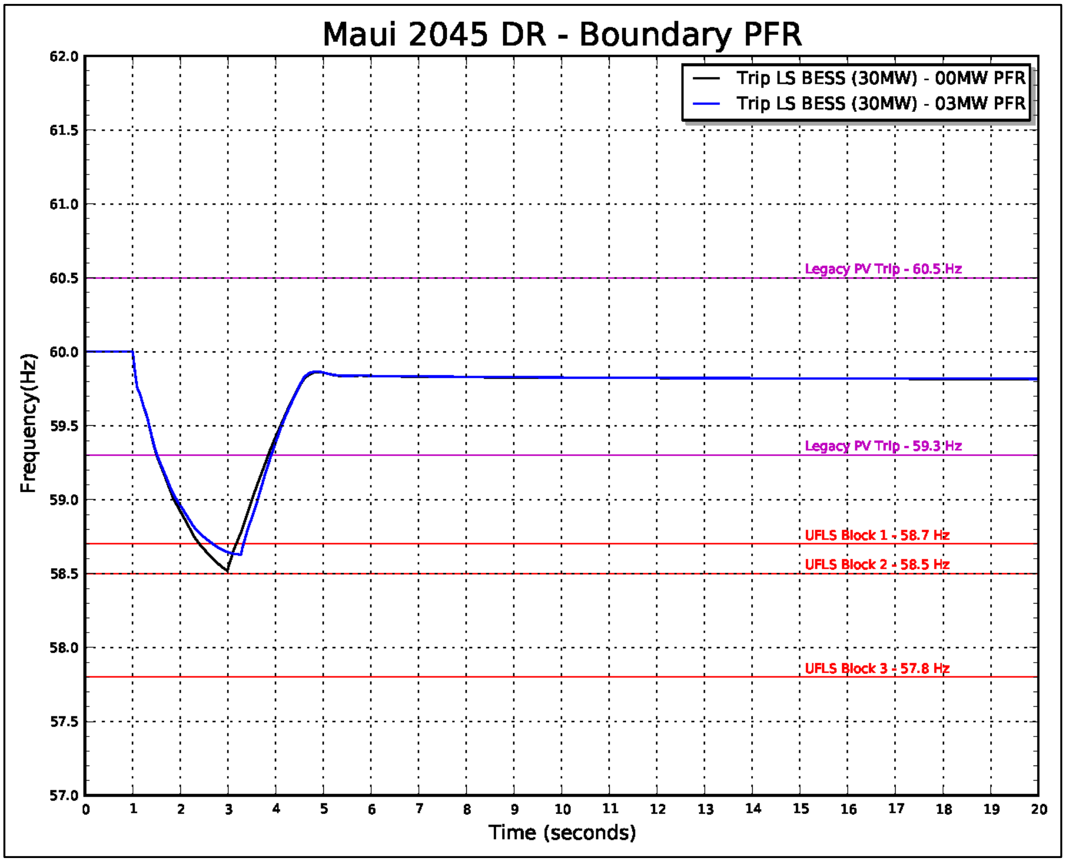

Figure O-290. Frequency Response Profile for PFR Boundary Hour

Figure O-290 shows the frequency response profile for the PFR analysis. The capacity of PFR required to meet the requirements of TPL-001 is 3 MW.

E3 Resource Plan Assessment

The full scope of the system security analysis was not completed for the E3 resource plans. Analysis and assessment focused on the No LNG; High DG-PV plan.

E3 - No LNG; High DG-PV

- Loss of Generation Screening (2019 – 2021): Screening results indicate slightly degraded system performance stating in 2020. The E3 plan has 406 hours that require additional frequency response resources to meet TPL-001. The Post April DR plan has 309 hours. In 2021, E3 has 443 hours compared to 325 hours.
- Loss of Generation Analysis (2019): FFR and PFR capacities required to bring the system into compliance with TPL-001 are similar to the Post April DR plan.
- 69 kV Fault Analysis (2019): Thirty-one simulations were unstable compared to four simulations for the Post April DR plan.

Maui Summary

The system security analysis determines technology-neutral requirements for each resource plan to ensure compliance with TPL-001. Analysis focused on 2019 through 2021 to ensure the resource plans meet system security requirements through the 5-year action plan period. System security analyses include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation contingency analysis was performed for select years beyond 2021.

Minimum Fault Current

A minimum fault current analysis was not performed for Maui. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Maui transmission system requires 72 MVA on the 69 kV system; and 30 MVA on the 23 kV system.

QV Analysis

The Maui transmission system is designed to operate with one transmission line out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability.

Only synchronous generators and synchronous condensers provide fault current to meet the minimum fault current requirements. Therefore, only synchronous condensers are evaluated in these analyses since resource plans tend to displace must-run units.

For Maui, the critical busses with the highest MVAR demand are the Wailea, Kihei, and Waiinu busses. These critical busses determine the reactive power requirements for the system.

A new 30 MVA synchronous condenser is required in 2020 for both the Theme 3 No-DR and the Post April DR plans.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production simulation data to represent a typical condition and a boundary condition. If screening analysis resulted in limited hours, only a boundary hour was analyzed.

For the Theme 3 No-DR resource plan, analysis was performed to determine the capacities of FFR1, FFR2, and PFR required to bring the system into compliance with TPL-001. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW. Table O-203 (page O-616) shows the results of the analysis.

For the Post April DR resource plan, analysis was performed to determine the capacities of FFR1 and PFR required to bring the system into compliance with TPL-001. Unlike O'ahu, Maui does not have FFR2 in their Demand Response portfolio. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW. Table O-204 (page O-616) shows the results of the analysis.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system through the 5-year action plan. Results indicate that the system is susceptible to collapse on normally cleared three-phase faults in 2019.

Non-exhaustive sensitivity analyses were performed for normally cleared faults to stabilize system frequency and bring the system into compliance with TPL-001. Simulations were performed to determine the capacity of PFR required to bring the system into compliance with TPL-001 and to evaluate 5-cycle clearing time to simulate performance of dual pilot or dual differential relay schemes. Table O-126 shows the results of the PFR analysis to bring the system into compliance with TPL-001.

Year	PFR (MW)		
	No DR	No DR w/5 cycle clearing	DR
2019	70	35	48
2020	60	35	70
2021	90	70	38

Table O-126. Summary of Results PFR Analysis

Maui is already in the process of implementing dual differential relays schemes and replacing 69 kV breakers to reduce fault clearing times. Further analysis is required to determine optimal mitigating strategies to maintain system security.

LANA'I SYSTEM SECURITY ANALYSIS

State of the System

The island of Lana'i has a relatively small capacity of DG-PV so system performance has not been adversely affected like the other islands. The 1 MW Lana'i Solar Farm also has a BESS to help regulate frequency.

2017

Loss of Generation Simulation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. Simulations were run for day and night base case dispatches.

Unit	Unit Ratings					Basecase - Miki Basin 7 Trip Day			Basecase - Miki Basin 7 Trip Evening		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43						
LANAI2	1.00	0.50	0.34	1.25	0.43						
LANAI3	1.00	0.50	0.34	1.25	0.43						
LANAI4	1.00	0.50	0.34	1.25	0.43						
LANAI5	1.00	0.50	0.34	1.25	0.43						
LANAI6	1.00	0.50	0.34	1.25	0.43						
L7,D-7	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50	2.00	0.20	1.70
L8,D-8	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50	2.00	0.20	1.70
CHP	0.83	0.00	0.34	1.25	3.03	0.83			0.83		
DG-PV	1.57	0.00				0.29	0.46		0.00	0.00	
LSR PV	1.00	0.00				0.80	0.80		0.00	0.00	
Total System MVA							6.75			6.75	
Total Kinetic Energy							9.08			9.08	
Total Load							5.69			4.83	
Total Thermal Generation							4.43			4.83	
Total Renewable Generation							1.26			0.00	
Total Generation							5.69			4.83	
Excess Generation							0.00			0.00	
Total Up Regulation							0.80			0.40	
Total Down Regulation							3.00			3.40	
Legacy DG-PV	59.3Hz Capacity				0.10	59.3Hz Output		0.07	59.3Hz Output		0.00
	60.5Hz Capacity				0.46	60.5Hz Output		0.30	60.5Hz Output		0.00

Table O-127. Unit Commitment and Dispatch 2017

Table O-127 shows the unit commitment and dispatch schedules for the daytime and nighttime base case simulations.

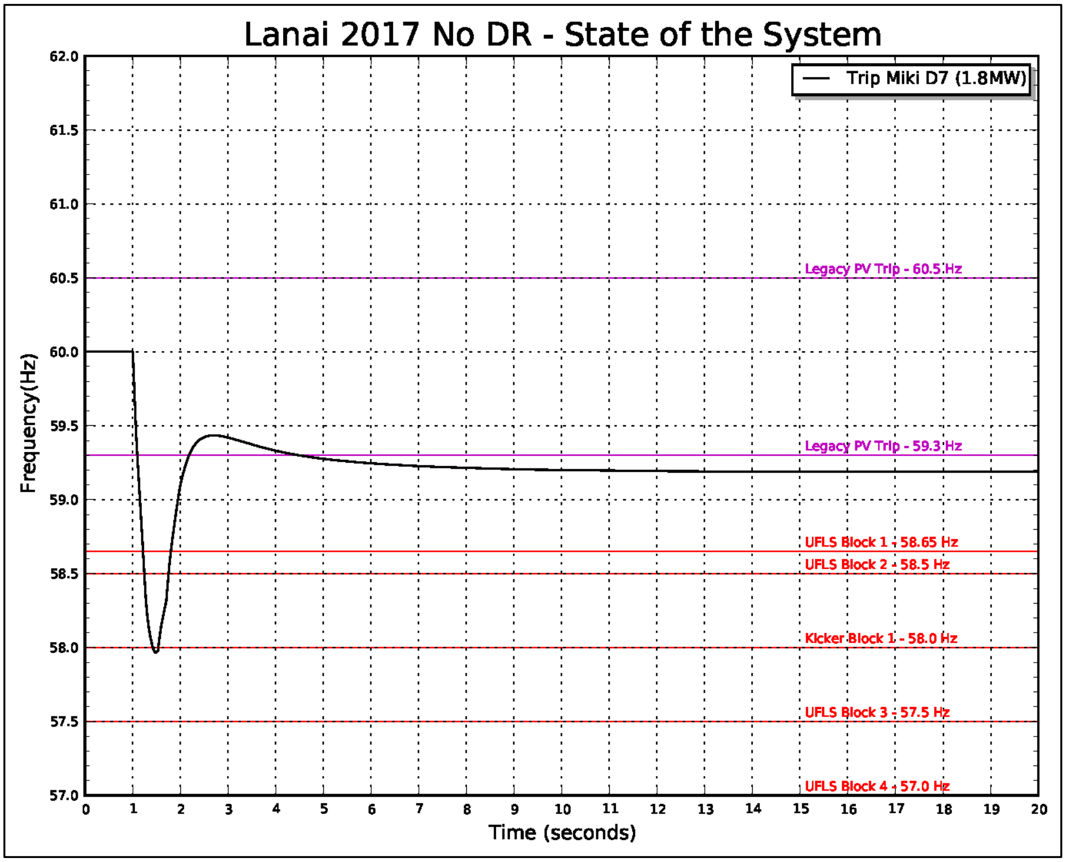

Figure O-291. Frequency Response Profile Day Base Case

Figure O-291 shows the frequency response profile for a Miki Basin diesel engine trip at 1.8 MW during the day. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV that will disconnect from the system is 460 kW. The frequency breaches 58.0 Hz and two blocks of UFLS are required to stabilize system frequency.

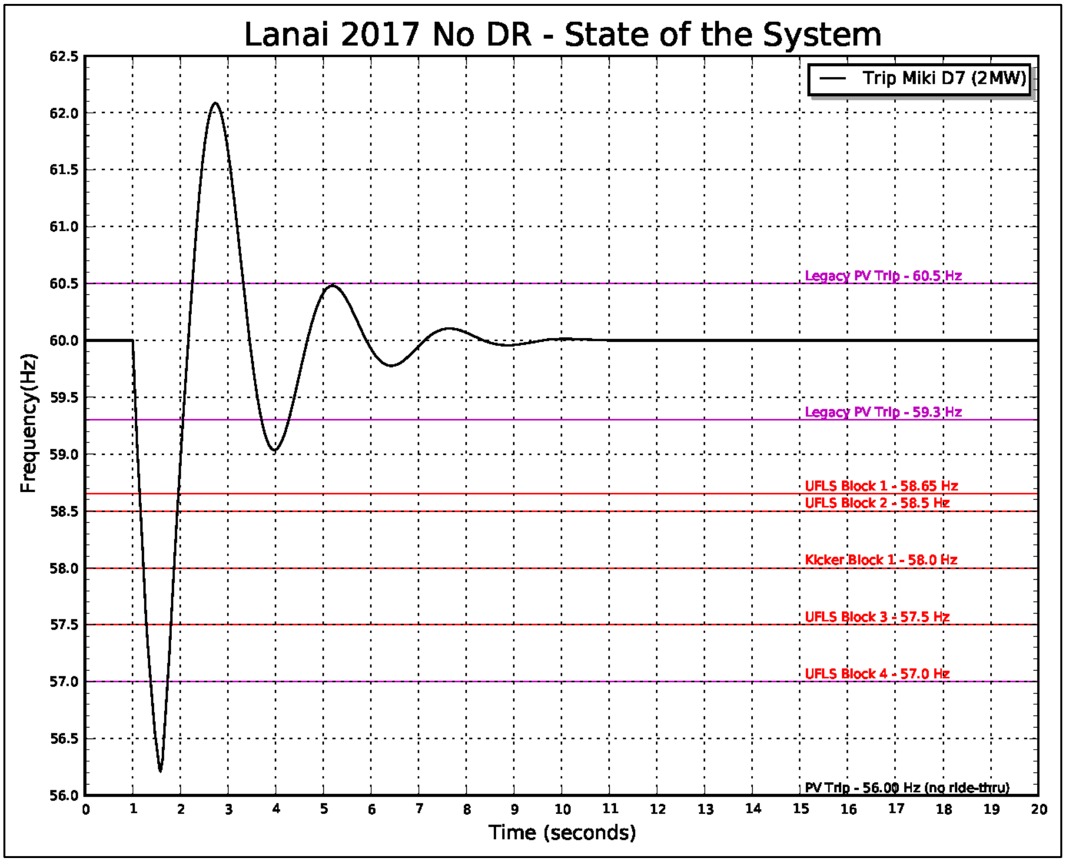

Figure O-292. Frequency Response Profile Night Base Case

Figure O-292 shows the frequency response profile for a Miki Basin diesel engine trip at 2.0 MW during the night. System kinetic energy is 9.1 MW-sec. The frequency breaches 56.4 Hz and four blocks of UFLS are required to stabilize system frequency.

12kV Fault Simulation

Simulations were performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Pala'au is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Pala'au are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	Unit Ratings					Basecase - Fault Day		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50
L8,D-8	2.20	0.30	1.10	2.75	3.03	1.80	0.40	1.50
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
DG-PV	1.57	0.00				0.29	0.46	
LSR PV	1.00	0.00				0.80	0.80	
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							5.69	
Total Thermal Generation							4.43	
Total Renewable Generation							1.26	
Total Generation							5.69	
Excess Generation							0.00	
Total Up Regulation							0.80	
Total Down Regulation							3.00	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.07
	60.5Hz Capacity			0.46		60.5Hz Output		0.30

Table O-128. Unit Commitment and Dispatch Fault Analysis 2017

Table O-128 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 1.26 MW.

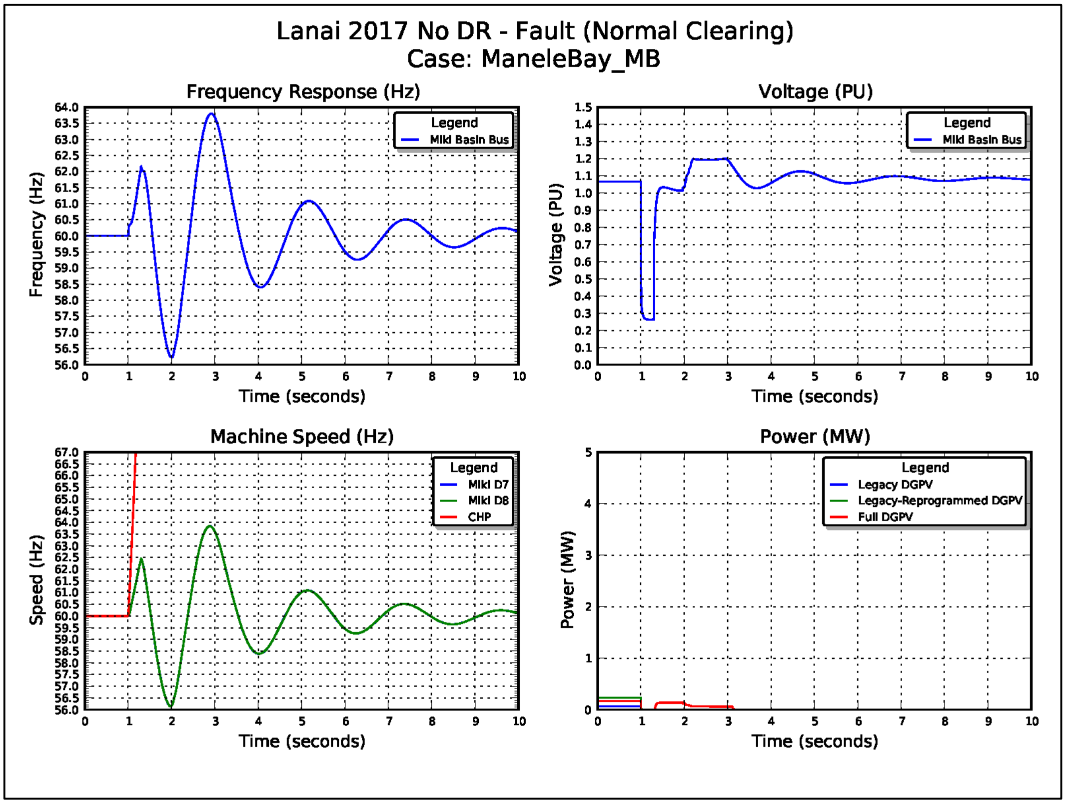

Figure O-293. System Performance Normally Cleared Fault

Figure O-293 shows the system performance for a normally cleared fault on the Manele Bay distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where 460 kW inverter-based generation drops to zero. System frequency swings from a nadir of 56.0 Hz to an apex of 64.0 Hz but the oscillation eventually dampens. Four blocks of UFLS are required to help stabilize system frequency. The system maintains stability for all distribution circuit faults.

Post April Plan

System security analysis was performed on the Post April DR plan include loss of generation analysis and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

The Lana'i system is a nominal 12 kV radial distribution system that does not fall under the jurisdiction of TPL-001. Distribution system reliability is driven by CAID and SAID indices as opposed to equivalent forced outage rate (EFOR). Therefore, the reliability criterion that was used for the frequency response analysis is to prevent system collapse and to maintain acceptable stability margin.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

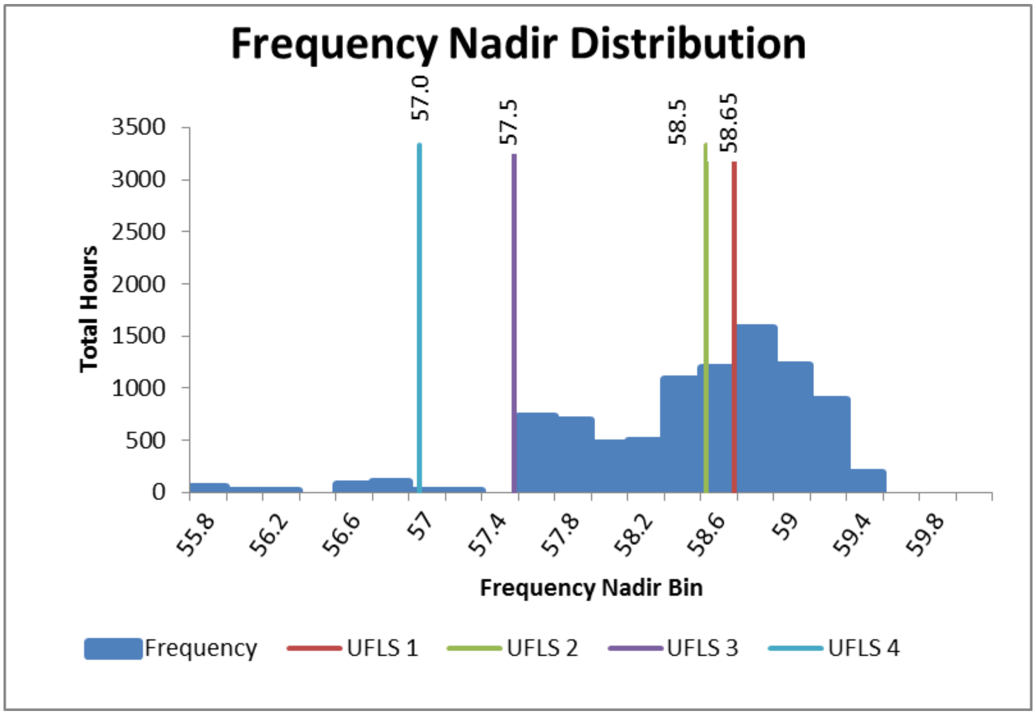

Figure O-294. Frequency Nadir Histogram

Figure O-294 Figure O-295is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the production simulations. The boundary hour selected from a minimum distribution of 231 hours was 4:00 PM on Friday, October 18. The frequency nadir range for the boundary hour is > 57.0 Hz.

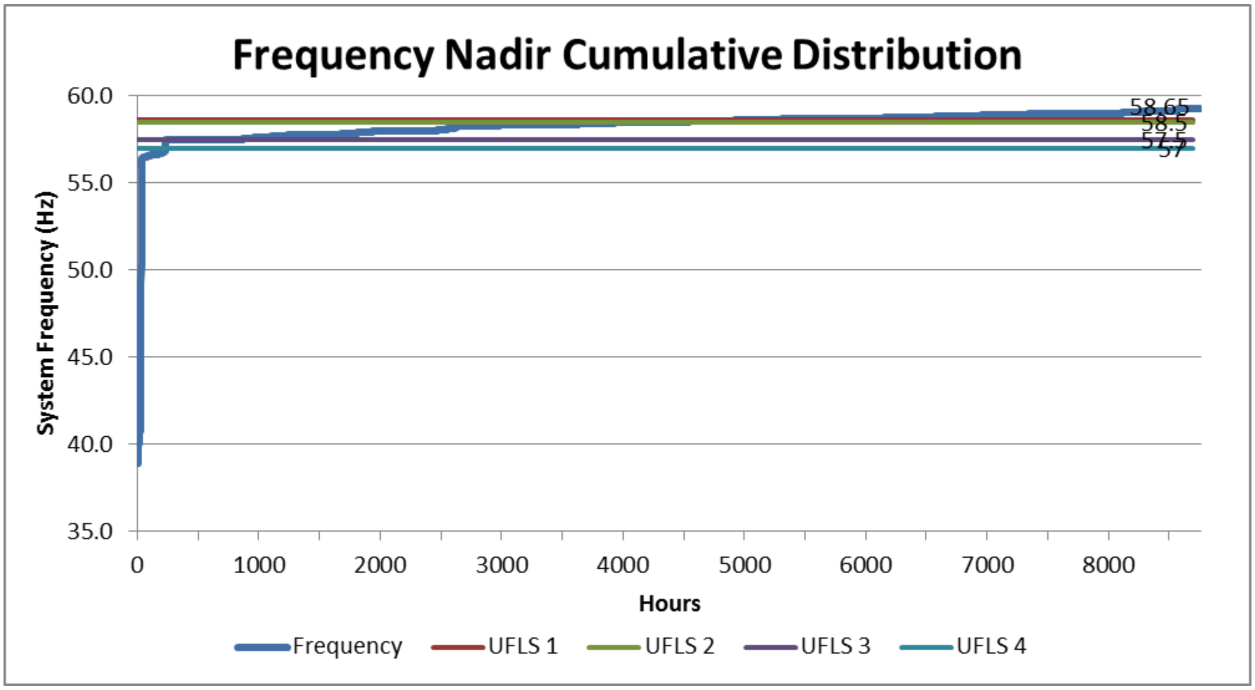

Figure O-295. Frequency Nadir Duration Curve

Figure O-295 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of deploying all four blocks of UFLS for 231 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 7 Trip Boundary 10/18/19 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03	1.24	0.96	0.94
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
DG-PV	1.57	0.00				0.54		
LSR PV	1.00	0.00				0.88		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							3.50	
Total Thermal Generation							2.07	
Total Renewable Generation							1.42	
Total Generation							3.49	
Excess Generation							-0.01	
Total Up Regulation							0.96	
Total Down Regulation							0.94	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.04
	60.5Hz Capacity			0.46		60.5Hz Output		0.19

Table O-129. Unit Commitment and Dispatch 2019

Table O-129 shows the unit commitment and dispatch for the boundary hour (10/18/19, 2:00 PM).

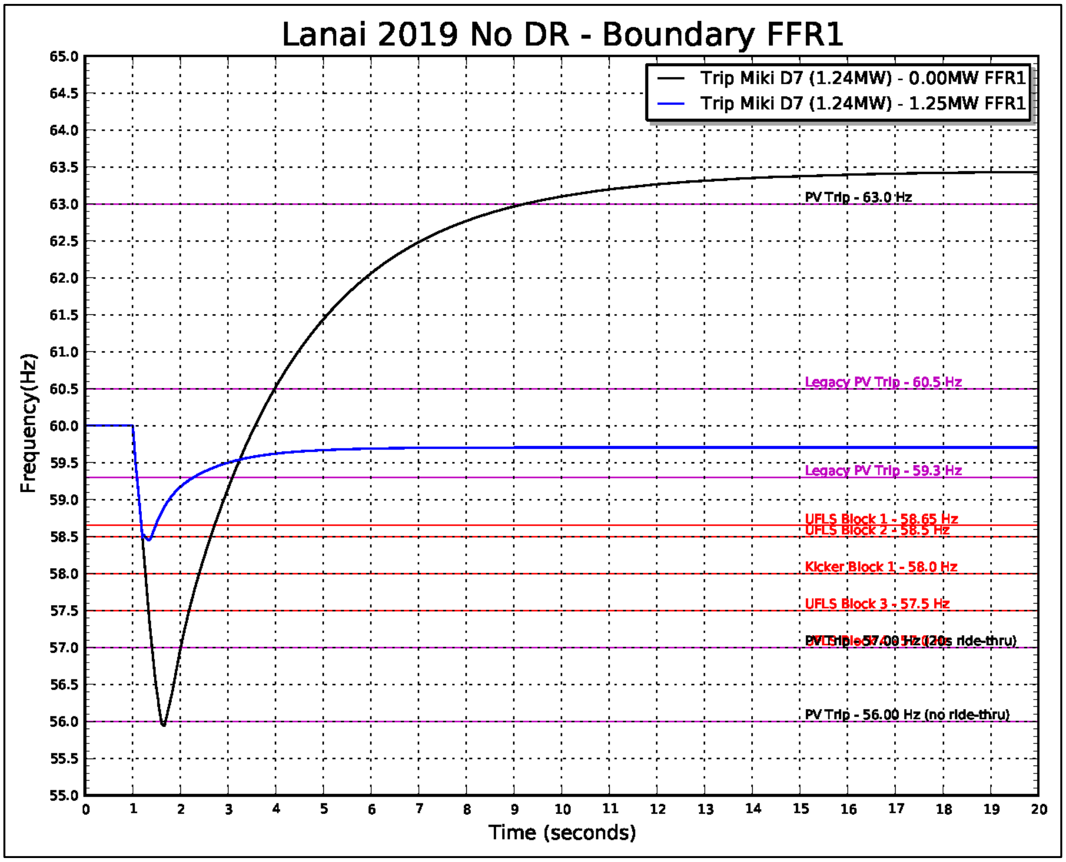

Figure O-296. Frequency Response Profile FFR1

Figure O-296 shows the frequency response profile for a Miki Basin 7 trip at 1.24 MW for a boundary hour. System kinetic energy is 9.1 MW-sec. The capacity of legacy PV is negligible. The frequency nadir breaches 56.0 Hz and four blocks of UFLS are required to stabilize system frequency but the aggregate response over-compensates and drives the frequency apex to 63.5 Hz; a 7.5 Hz peak-to-peak swing. The capacity of FFR1 required to stabilize system frequency is 1.25 MW.

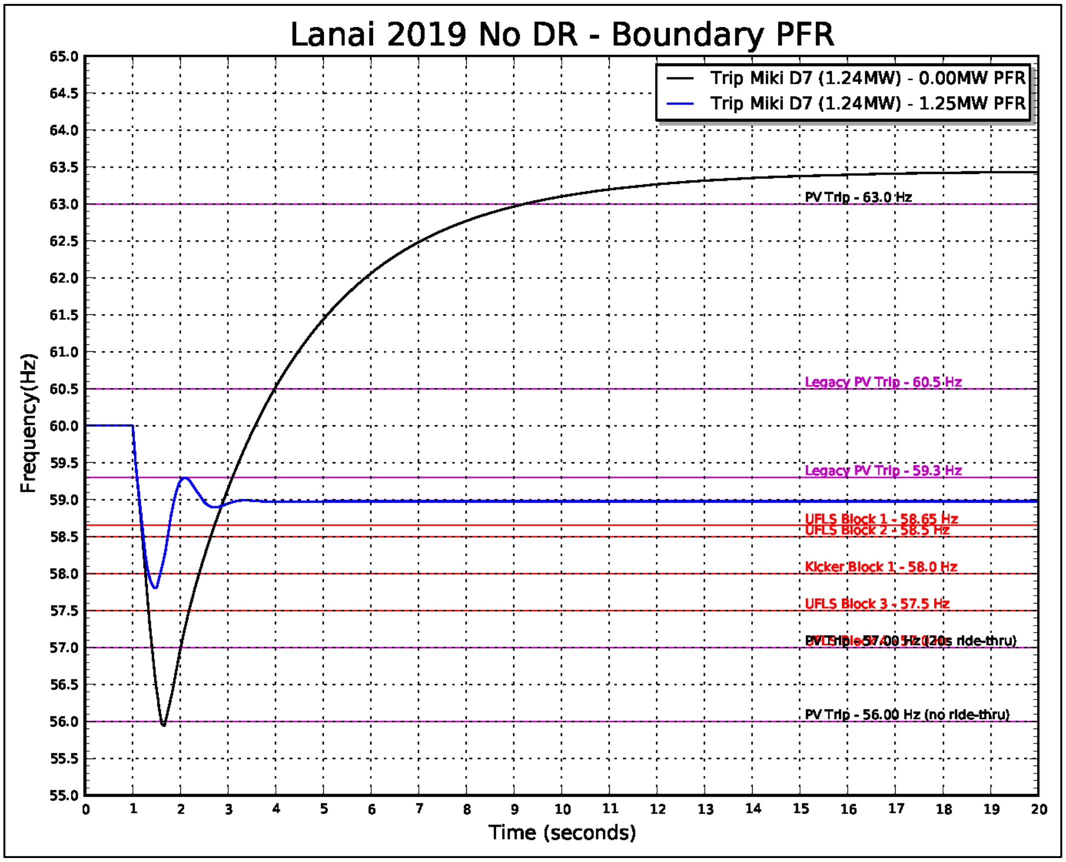

Figure O-297. Frequency Response Profile PFR

Figure O-297 shows the frequency response profile for the PFR analysis. The capacity of PFR required to stabilize system frequency is 1.25 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Pala'au is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Pala'au are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Unit	Unit Ratings					No DR - Fault 3/18/19 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43	0.50	0.50	0.00
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43	0.57	0.43	0.07
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03		*Synchronous Condenser*	
DG-PV	1.57	0.00				1.13		
LSR PV	1.00	0.00				0.85		
Total System MVA							6.50	
Total Kinetic Energy							6.91	
Total Load							3.88	
Total Thermal Generation							1.90	
Total Renewable Generation							1.98	
Total Generation							3.88	
Excess Generation							0.00	
Total Up Regulation							0.93	
Total Down Regulation							0.07	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.08
	60.5Hz Capacity			0.46		60.5Hz Output		0.39

Table O-130. Unit Commitment and Dispatch Fault Analysis 2019

Table O-130 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 1.98 MW.

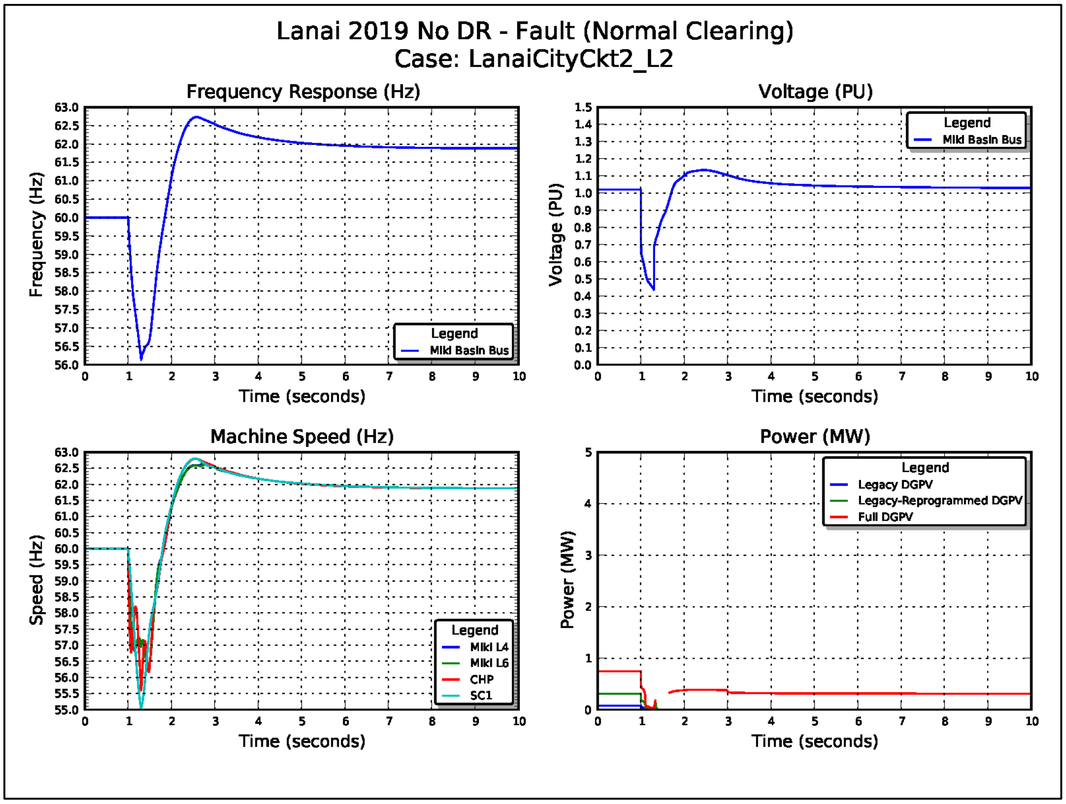

Figure O-298. System Performance Normally Cleared Fault

Figure O-298 shows the system performance for a normally cleared fault on the Lanai City 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 1.13 MW from inverter-based generation drops to zero. System frequency initially decreases but the aggregate response of the remaining diesel unit, four blocks of UFLS, and restoration of DG-PV over-compensates and drives the frequency apex above 62.5 Hz. The system maintains stability for all distribution circuit faults.

2020

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

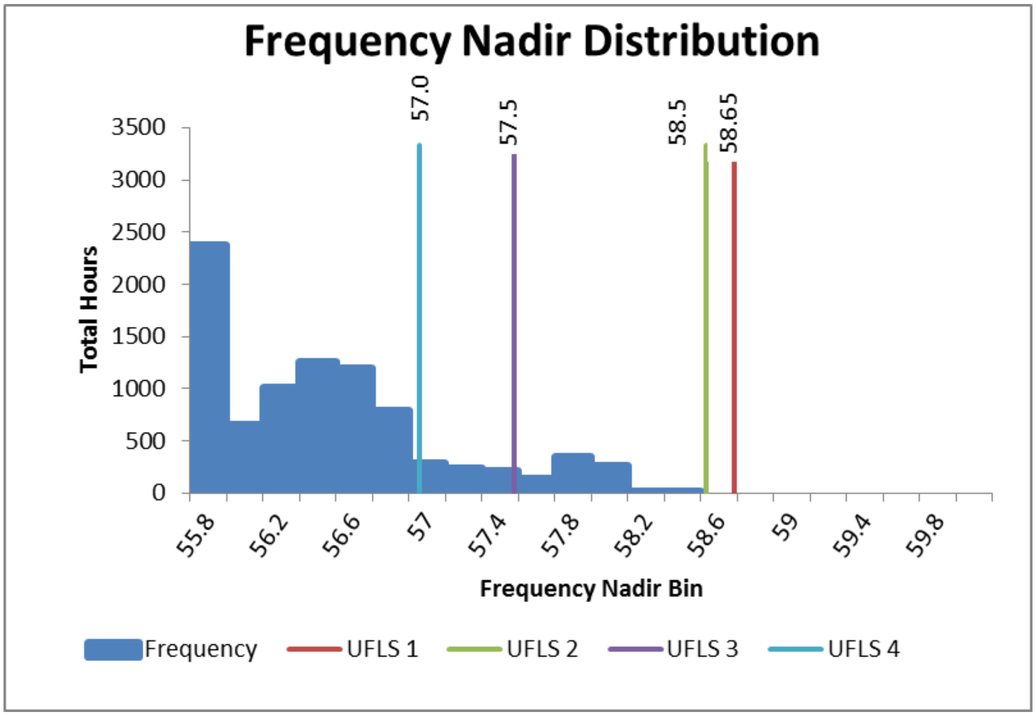

Figure O-299. Frequency Nadir Histogram 2020

Figure O-299 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 7543 hours was 4:00 PM on Monday, December 7. The frequency nadir range for the boundary hour is > 57.0 Hz.

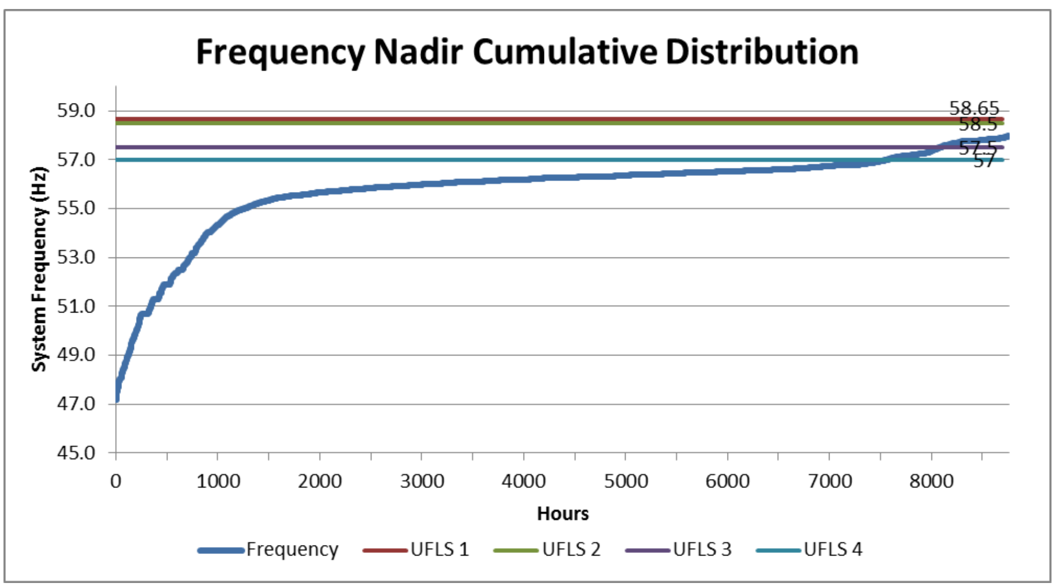

Figure O-300. Frequency Nadir Duration Curve 2020

Figure O-300 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of deploying all four blocks of UFLS for 7543 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 8 Trip Boundary 12/7/20 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.20	0.00	1.90
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	1.68	0.00				0.45		
LSR PV	1.00	0.00				0.80		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							4.28	
Total Thermal Generation							3.03	
Total Renewable Generation							1.26	
Total Generation							4.29	
Excess Generation							0.01	
Total Up Regulation							0.00	
Total Down Regulation							1.90	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.03
	60.5Hz Capacity			0.46		60.5Hz Output		0.15

Table O-131. Unit Commitment and Dispatch 2020

Table O-131 shows the unit commitment and dispatch for the boundary hour (12/7/20, 4:00 PM).

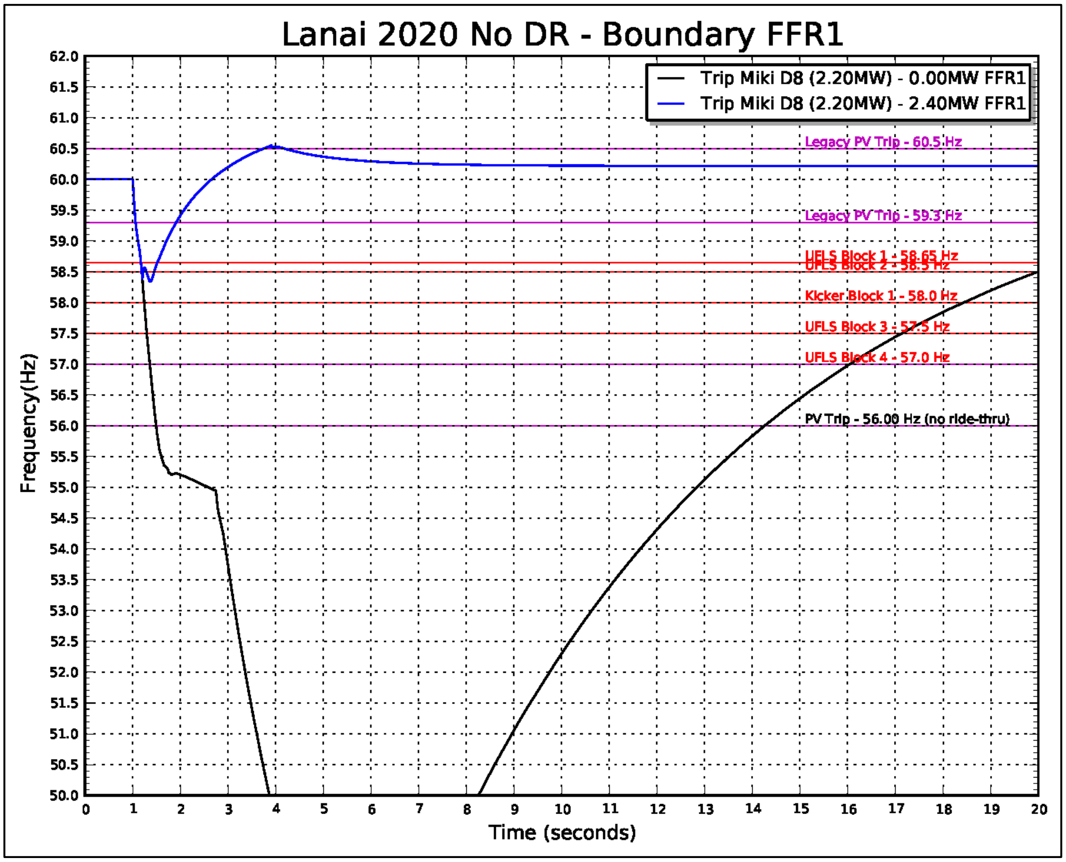

Figure O-301. Frequency Response Profile FFR1

Figure O-301 shows the frequency response profile for a Miki Basin 8 trip at 2.2 MW for a boundary hour. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV is negligible. The frequency nadir dips below 50.0 Hz and four blocks of UFLS and the kicker block are required to stabilize system frequency. The capacity of FFR1 required to limit UFLS to two blocks and add a margin of stability is 1.25 MW.

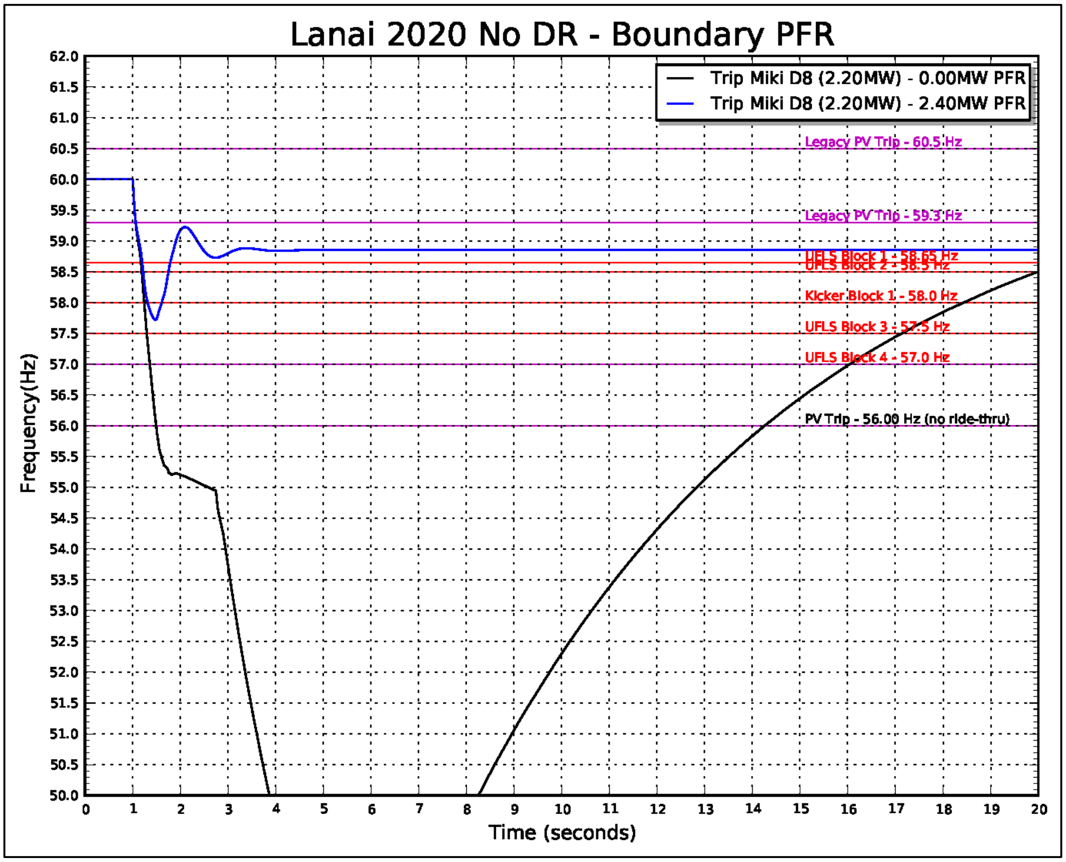

Figure O-302. Frequency Response Profile PFR

Figure O-302 shows the frequency response profile for the PFR analysis. The capacity of PFR required to add stability to the system is 2.4 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Pala'au is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Pala'au are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Unit	Unit Ratings					No DR - Fault 3/10/20 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43	0.51	0.49	0.01
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	1.68	0.00				1.18		
LSR PV	1.00	0.00				0.91		
Total System MVA						5.25		
Total Kinetic Energy						6.48		
Total Load						3.84		
Total Thermal Generation						1.34		
Total Renewable Generation						2.09		
Total Generation						3.42		
Excess Generation						-0.42		
Total Up Regulation						0.49		
Total Down Regulation						0.01		
Legacy DG-PV	59.3Hz Capacity		0.10			59.3Hz Output		0.08
	60.5Hz Capacity		0.46			60.5Hz Output		0.39

Table O-132. Unit Commitment and Dispatch Fault Analysis 2020

Table O-132 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 1.19 MW.

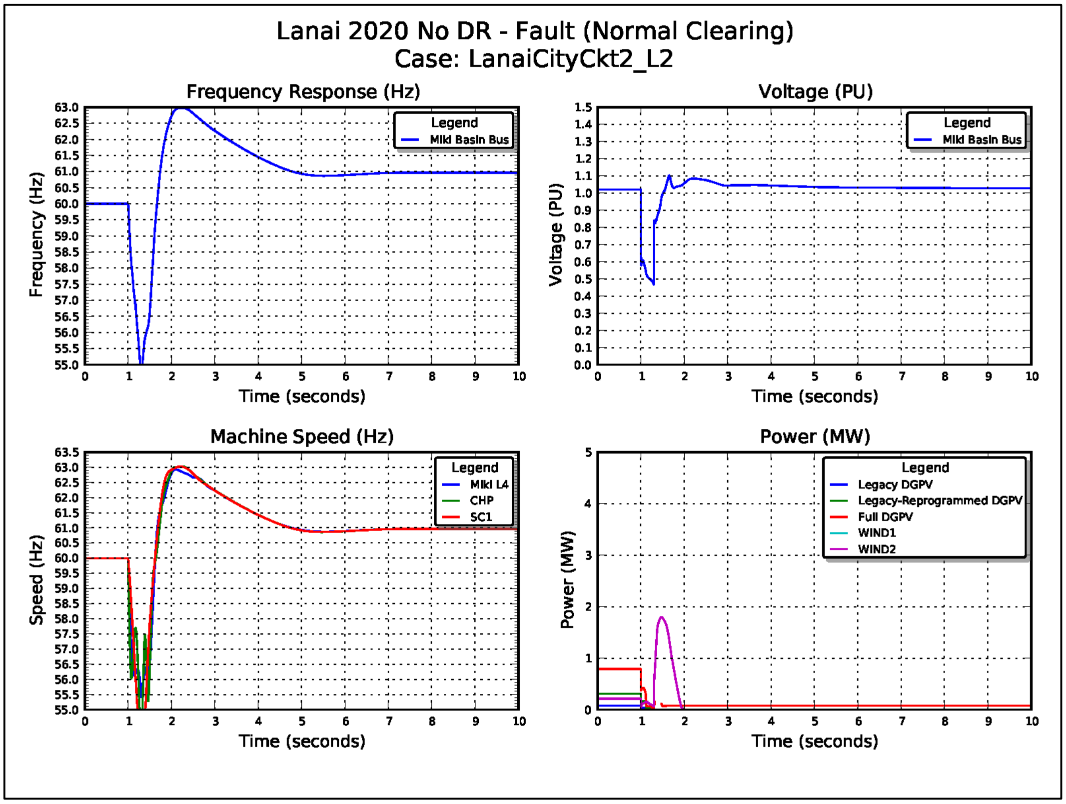

Figure O-303. System Performance Normally Cleared Fault

Figure O-303 shows the system performance for a normally cleared fault on the Lanai City 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 1.61 MW from inverter-based generation drops to zero. System frequency initially decreases but the aggregate response of four blocks of UFLS and droop response from the wind farm over-compensates, driving the frequency apex above 63 Hz before stabilizing above 60 Hz. The system maintains stability for all distribution circuit faults.

2021

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

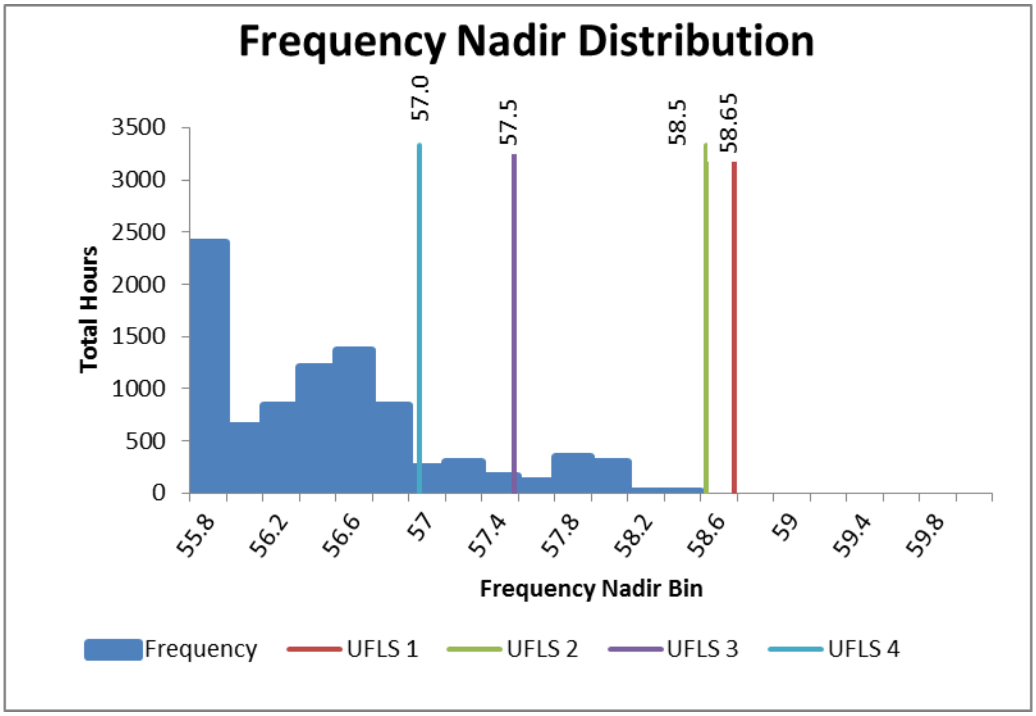

Figure O-304. Frequency Nadir Histogram 2021

Figure O-304 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 7518 hours was 4:00 PM on Monday, December 7. The frequency nadir range for the boundary hour is > 57.0 Hz.

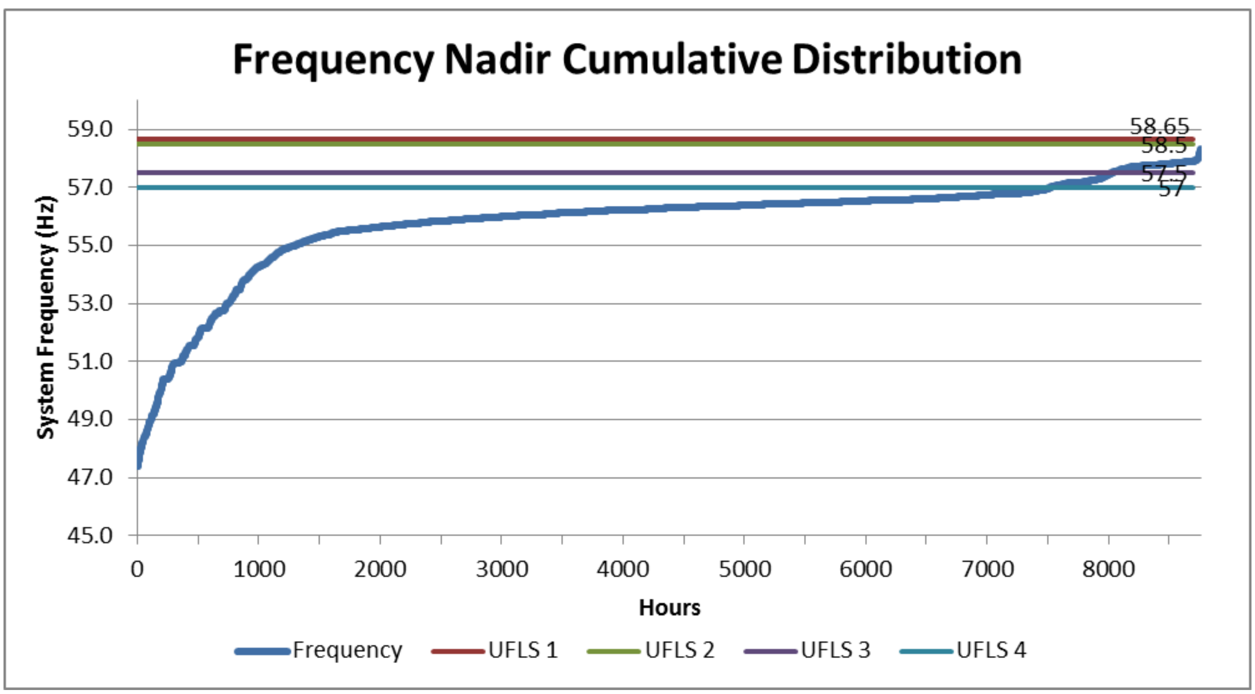

Figure O-305. Frequency Nadir Duration Curve 2021

Figure O-305 shows the frequency nadir duration curve for the resource plan in 2021. The system is at risk of deploying all four blocks of UFLS for 7518 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 8 Trip Boundary 12/22/21 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.17	0.03	1.87
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	1.68	0.00				0.59		
LSR PV	1.00	0.00				0.80		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							4.39	
Total Thermal Generation							3.00	
Total Renewable Generation							1.39	
Total Generation							4.39	
Excess Generation							0.01	
Total Up Regulation							0.03	
Total Down Regulation							1.87	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.04
	60.5Hz Capacity			0.46		60.5Hz Output		0.19

Table O-133. Unit Commitment and Dispatch 2021

Table O-133 shows the unit commitment and dispatch for the boundary hour (12/7/20, 4:00 PM).

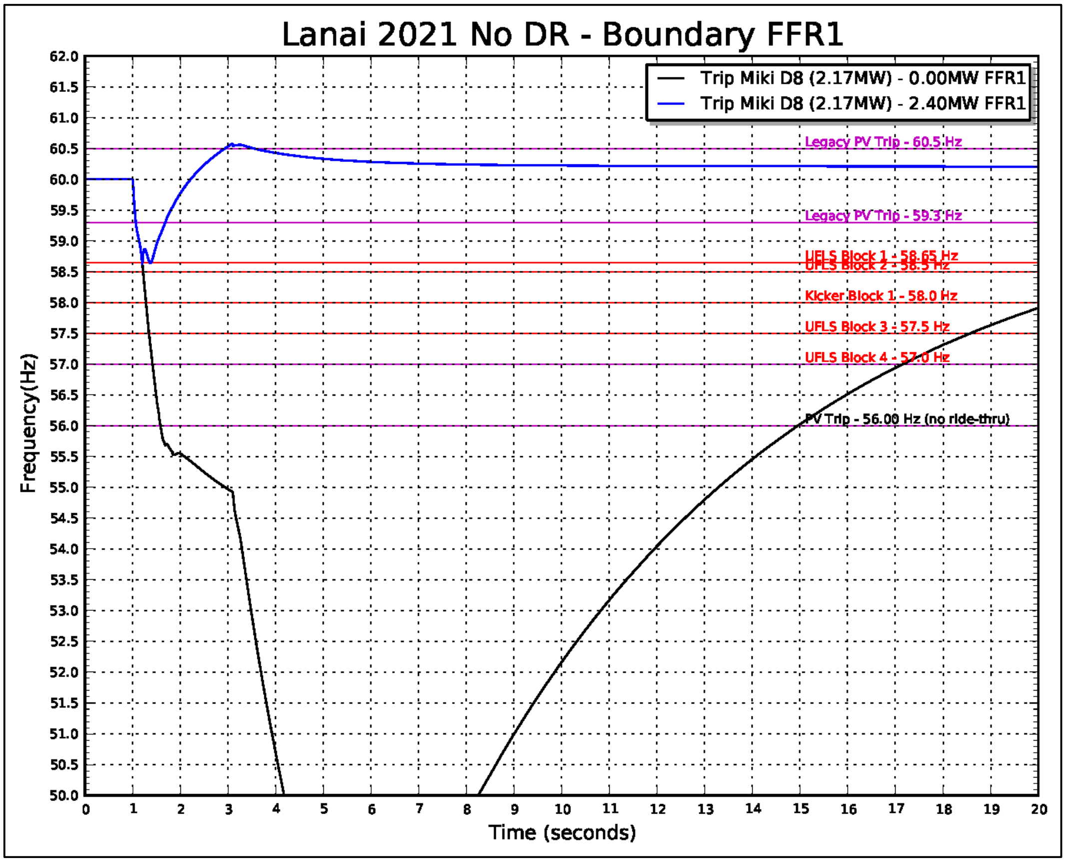

Figure O-306. Frequency Response Profile FFR1

Figure O-306 shows the frequency response profile for a Miki Basin 8 trip at 2.17 MW for a boundary hour. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV is negligible. The frequency nadir dips below 50.0 Hz and four blocks of UFLS and the kicker block are required to stabilize system frequency. The capacity of FFR1 required to stabilize system frequency is 2.4 MW.

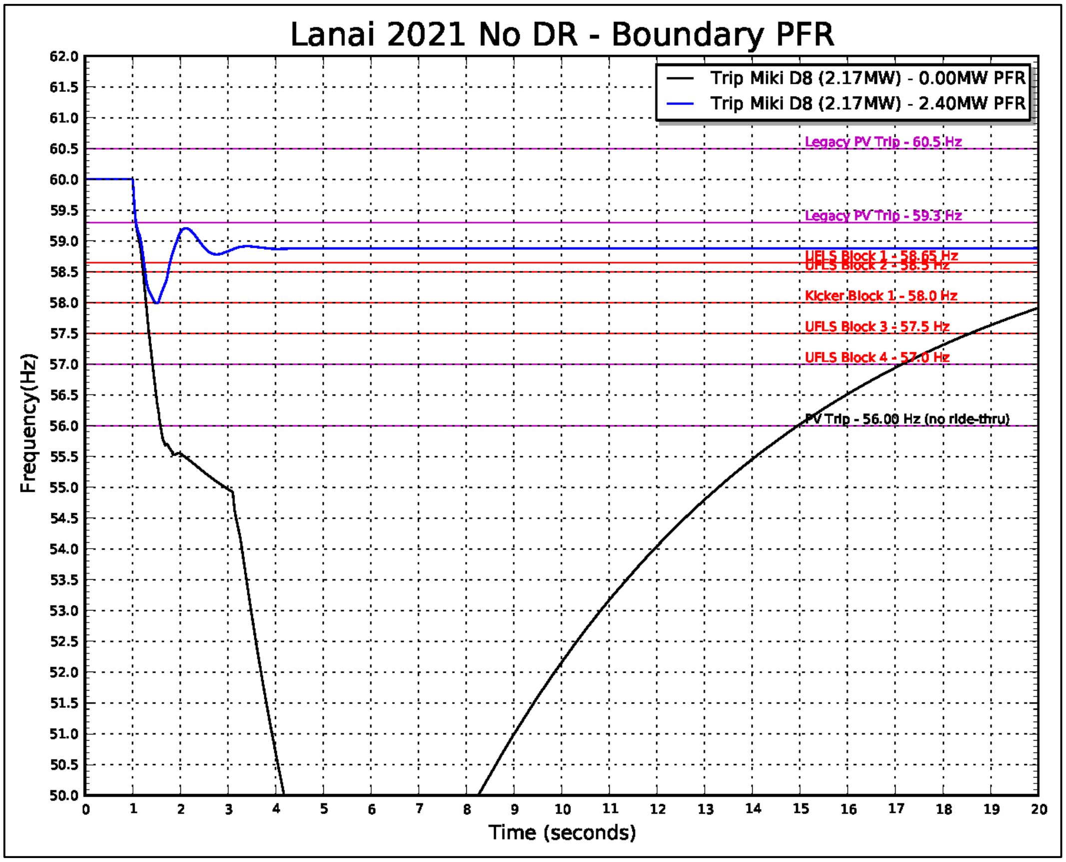

Figure O-307. Frequency Response Profile PFR

Figure O-307 shows the frequency response profile for the PFR analysis. The capacity of PFR required to stabilize system frequency is 2.4 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Pala'au is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Pala'au are cleared in 6-cycles and faults at the end of the circuit is cleared in 18-cycles.

Unit	Unit Ratings					No DR - Fault 3/13/21 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03			
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.48		
Wind2	2.00	0.00				0.48		
DG-PV	1.68	0.00				1.22		
LSR PV	1.00	0.00				0.89		
Total System MVA							4.00	
Total Kinetic Energy							6.05	
Total Load							3.90	
Total Thermal Generation							0.83	
Total Renewable Generation							3.07	
Total Generation							3.90	
Excess Generation							0.00	
Total Up Regulation							0.00	
Total Down Regulation							0.00	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.08
	60.5Hz Capacity			0.46		60.5Hz Output		0.39

Table O-134. Unit Commitment and Dispatch Fault Analysis

Table O-134 shows the unit commitment and dispatch for the 12 kV distribution fault analysis. The capacity from inverter-based generation is 2.11 MW.

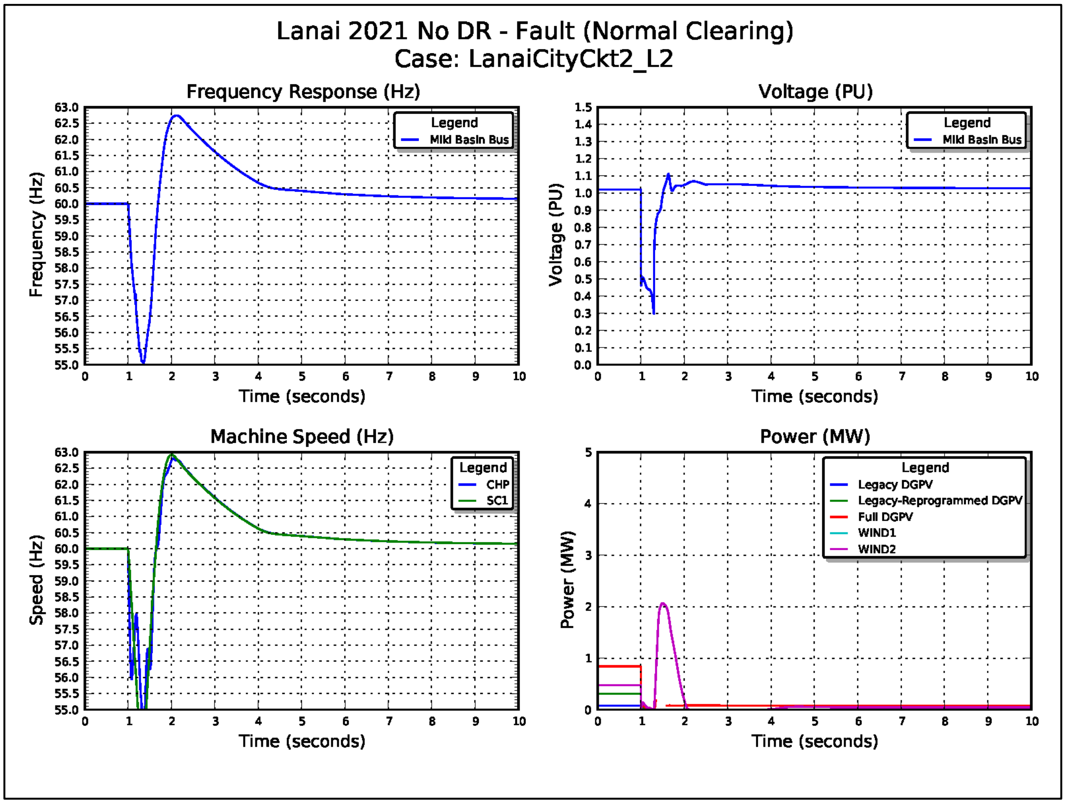

Figure O-308. System Performance Normally Cleared Fault

Figure O-308 shows the system performance for a normally cleared fault on the Lanai City 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 2.11 MW from inverter-based generation drops to zero. System frequency initially decreases to 55.0 Hz but the aggregate response of four blocks of UFLS and droop response from the wind farm over-compensates, driving the frequency apex above 62.5 Hz before stabilizing above 60 Hz. The system maintains stability for all distribution circuit faults.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

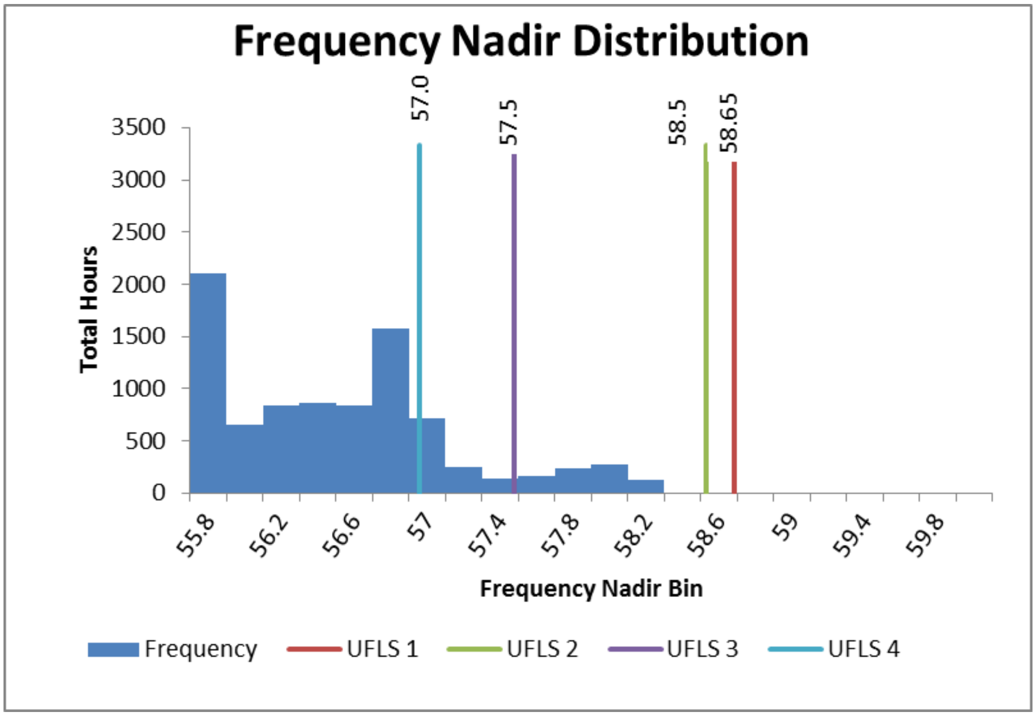

Figure O-309. Frequency Nadir Histogram

Figure O-309 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 4576 hours was 9:00 AM on Tuesday, January 29. The frequency nadir range for the boundary hour is > 57.0 Hz.

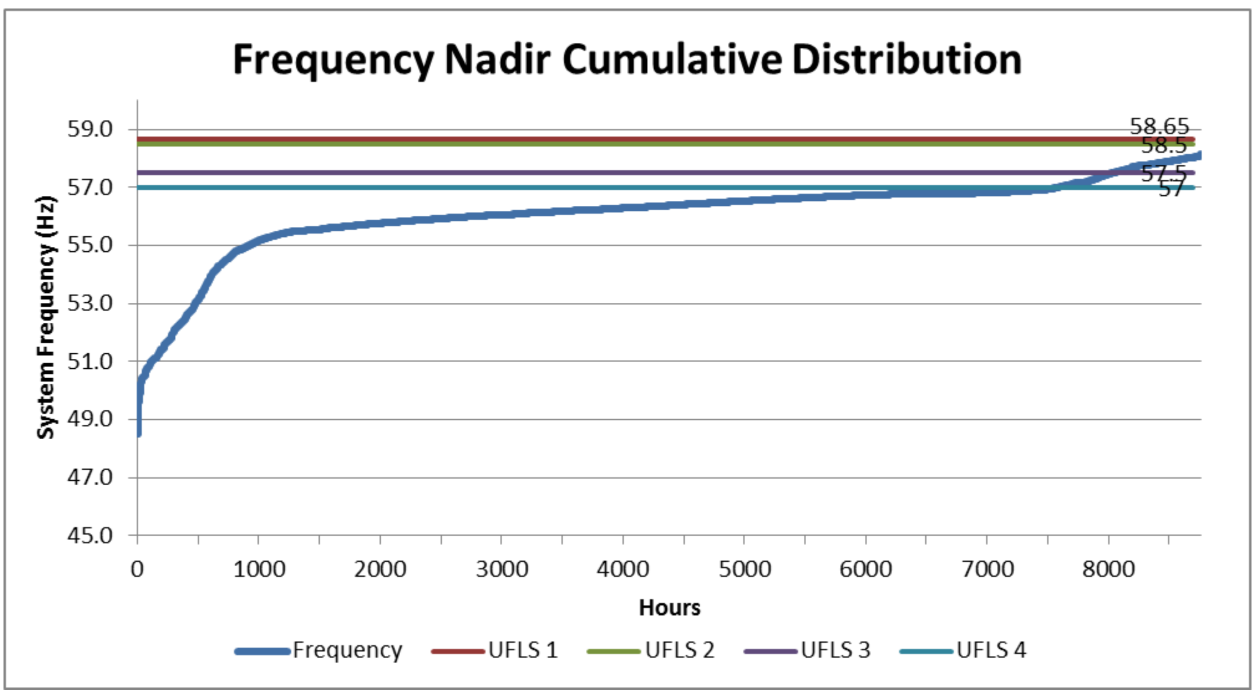

Figure O-310. Frequency Nadir Duration Curve 2030

Figure O-310 shows the frequency nadir duration curve for the resource plan in 2030. The system is at risk of deploying all four blocks of UFLS for 4576 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 8 Trip Boundary 1/29/30 Hour 9		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.15	0.05	1.85
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.00		
Wind2	2.00	0.00				0.00		
DG-PV	5.76	0.00				0.35		
LSR PV	1.00	0.00				0.70		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							4.02	
Total Thermal Generation							2.98	
Total Renewable Generation							1.04	
Total Generation							4.02	
Excess Generation							0.00	
Total Up Regulation							0.05	
Total Down Regulation							1.85	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.01
	60.5Hz Capacity			0.46		60.5Hz Output		0.04

Table O-135. Unit Commitment and Dispatch 2030

Table O-135 shows the unit commitment and dispatch for the boundary hour (1/29/30, 9:00 AM).

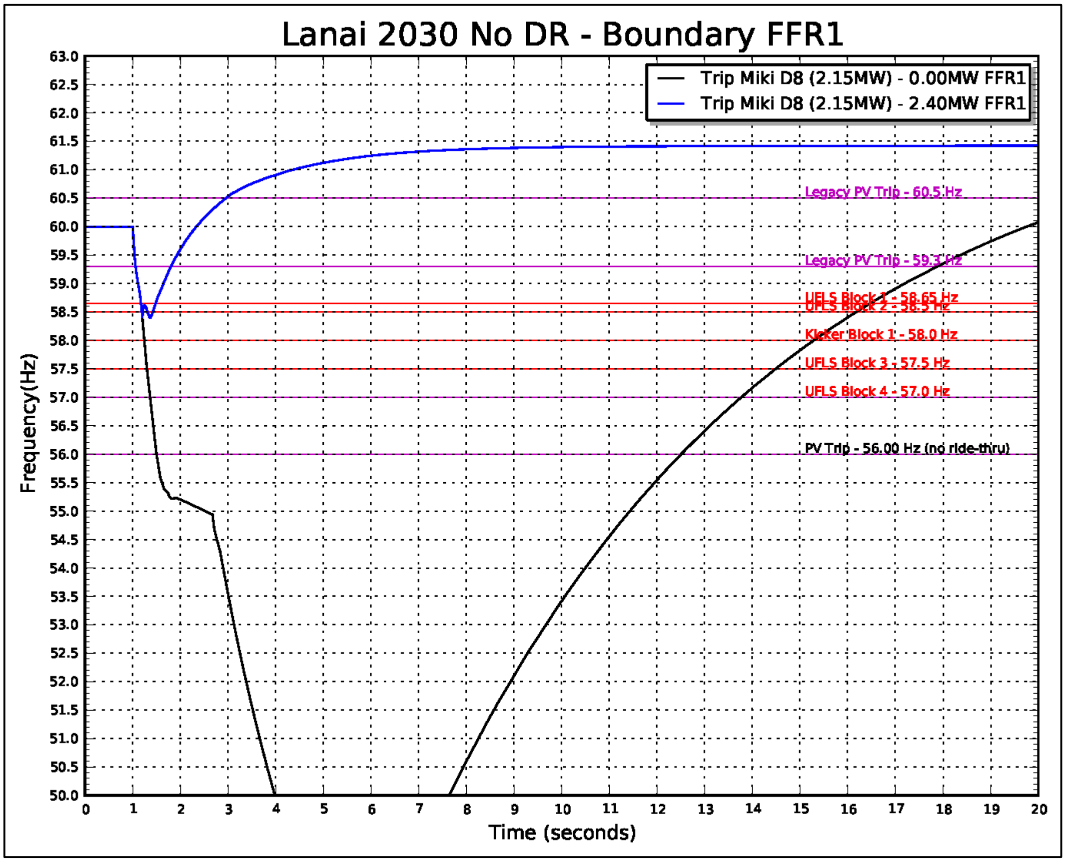

Figure O-311. Frequency Response Profile FFR1

Figure O-311 shows the frequency response profile for a Miki Basin 8 trip at 2.17 MW for a boundary hour. System kinetic energy is 9.1 MW-sec and the capacity of legacy PV is negligible. The frequency nadir dips below 50.0 Hz and four blocks of UFLS and the kicker block are required to stabilize system frequency. The capacity of FFR1 required to stabilize system frequency is 2.4 MW.

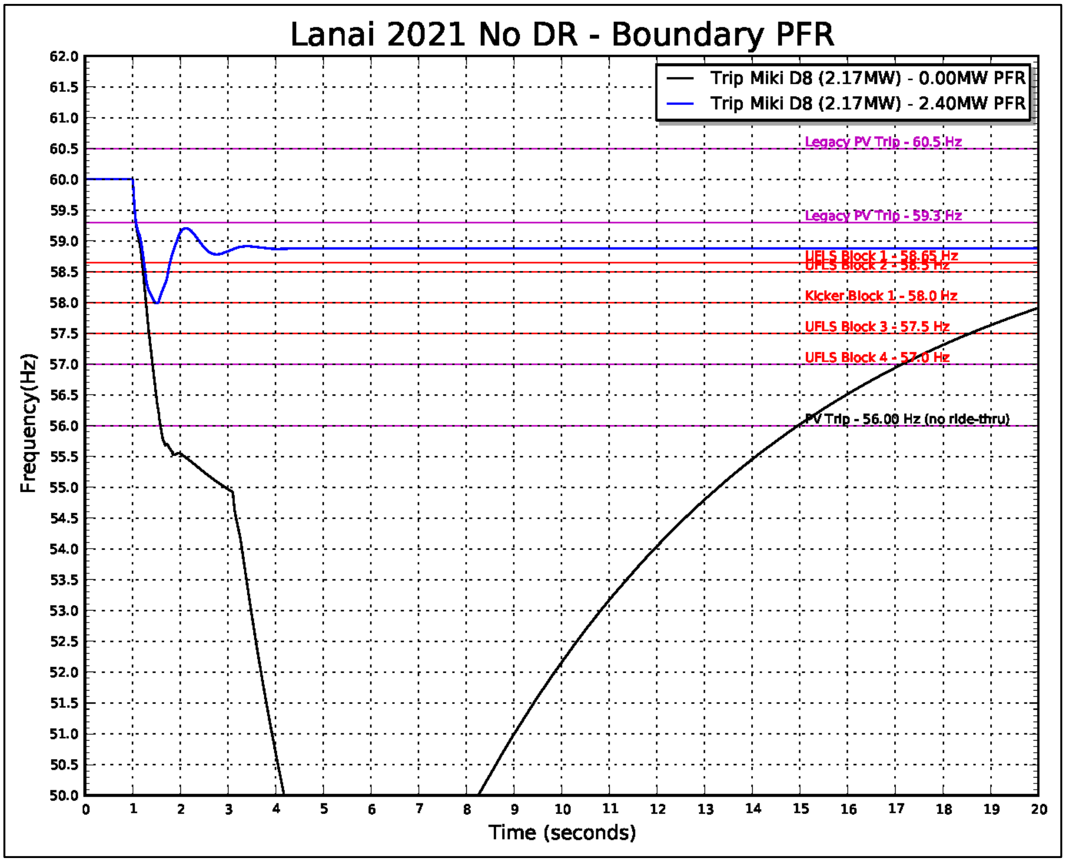

Figure O-312. Frequency Response Profile PFR

Figure O-312 shows the frequency response profile for the PFR analysis. The capacity of PFR required to stabilize system frequency is 2.4 MW.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

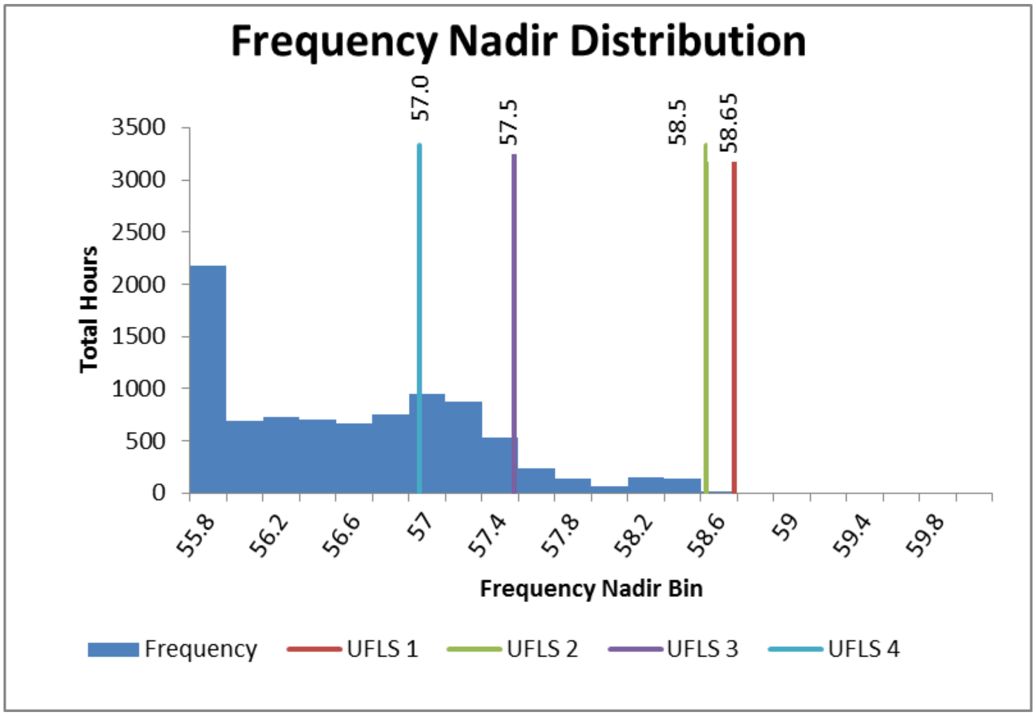

Figure O-313. Frequency Nadir Histogram

Figure O-313 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 6630 hours was4:00 AM on Thursday, February 23. The frequency nadir range for the boundary hour is > 57.0 Hz.

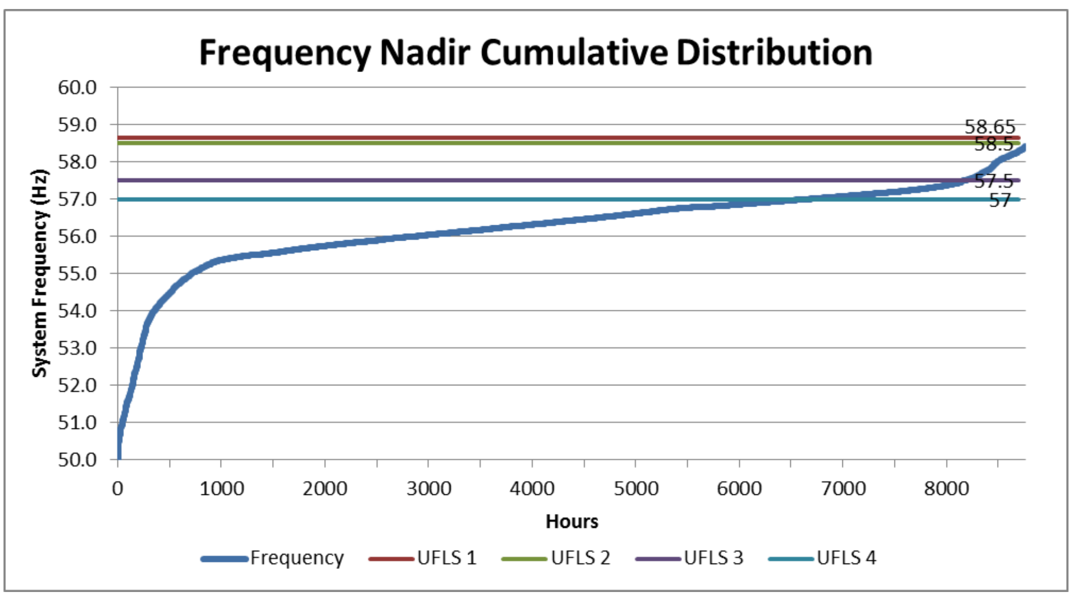

Figure O-314. Frequency Nadir Duration Curve

Figure O-314 shows the frequency nadir duration curve for the resource plan in 2045. The system is at risk of deploying all four blocks of UFLS for 6630 hours of the year.

Unit	Unit Ratings					No DR - Miki Basin 8 Trip Boundary 2/23/45 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
LANAI1	1.00	0.50	0.34	1.25	0.43			
LANAI2	1.00	0.50	0.34	1.25	0.43			
LANAI3	1.00	0.50	0.34	1.25	0.43			
LANAI4	1.00	0.50	0.34	1.25	0.43			
LANAI5	1.00	0.50	0.34	1.25	0.43			
LANAI6	1.00	0.50	0.34	1.25	0.43			
L7,D-7	2.20	0.30	1.10	2.75	3.03			
L8,D-8	2.20	0.30	1.10	2.75	3.03	2.15	0.05	1.85
CHP	0.83	0.00	0.34	1.25	3.03	0.83		
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.00	0.00				0.01		
Wind2	2.00	0.00				0.01		
DG-PV	11.85	0.00				0.00		
LSR PV	1.00	0.00				0.00		
Total System MVA							6.75	
Total Kinetic Energy							9.08	
Total Load							3.05	
Total Thermal Generation							2.98	
Total Renewable Generation							0.02	
Total Generation							3.00	
Excess Generation							-0.05	
Total Up Regulation							0.05	
Total Down Regulation							1.85	
Legacy DG-PV	59.3Hz Capacity			0.10		59.3Hz Output		0.00
	60.5Hz Capacity			0.46		60.5Hz Output		0.00

Table O-136. Unit Commitment and Dispatch 2045

Table O-136 shows the unit commitment and dispatch for the boundary hour (8/6/45, 12:00 PM).

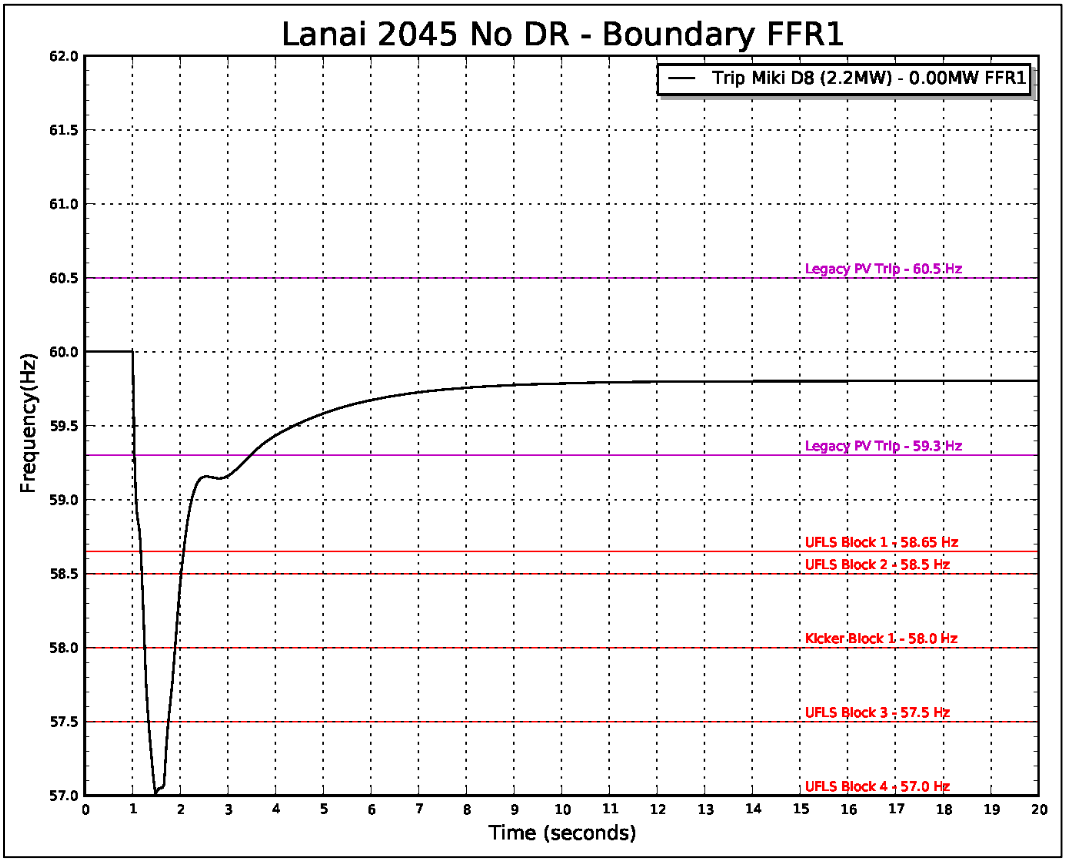

Figure O-315. Frequency Response Profile FFR1

Figure O-315 shows the frequency response profile for a Miki Basin 8 trip at 2.2 MW for a boundary hour. System kinetic energy is 6.1 MW-sec. The frequency nadir dips to 57.0 Hz and four blocks of UFLS are required to stabilize system frequency.

Lana'i Summary

The system security analysis determines technology-neutral requirements for the Post April resource plan to ensure the system is stable and maintains an acceptable stability margin. Lana'i is a nominal 12 kV radial distribution system that does not fall under the jurisdiction of TPL-001. System security analyses includes loss of generation analysis and fault analysis for years 2019-2021. Loss of generation contingency analysis was also performed for select years beyond 2021.

Minimum Fault Current

The Lana'i distribution system requires 2.75 MVA of fault current to ensure operation of protective relay schemes. A new 2.75 MVA synchronous condenser is required in 2019 to meet minimum fault current requirements.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected to represent a boundary condition.

The system is at risk for instability in 2019. Analysis indicates 1.25 MW of FFR1 or PFR is required to stabilize system frequency for a loss of generation contingency. Table O-205 (page O-617) shows the results of the analysis

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

The system remains stable for normally cleared faults on any distribution circuit so no sensitivity analyses were performed.

MOLOKA'I SYSTEM SECURITY ANALYSIS

State of the System

Unlike Lana'i , DG-PV penetration on Moloka'i is very high so the system potentially has excess energy during the day. A 2 MW contingency BESS that is owned by HNEI has been installed but is not operational at this time.

2017

Loss of Generation Simulation

Simulations were performed for the largest loss of generation contingency for day and night base case dispatches.

Unit	Unit Ratings					Basecase - Palaau 7 Trip Day			Basecase - Palaau 7 Trip Night		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43						
PALAAU2	1.25	0.31	0.34	1.25	0.43						
PALAAU3	0.97	0.31	0.34	1.25	0.43						
PALAAU4	0.97	0.31	0.34	1.25	0.43						
PALAAU5	0.97	0.31	0.34	1.25	0.43						
PALAAU6	0.97	0.31	0.34	1.25	0.43						
PA D7	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70	2.00	0.20	1.70
PA D8	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70	2.00	0.20	1.70
PA D9	2.20	0.30	1.10	2.75	3.03						
DG-PV	3.12	0.00				1.43			0.00		
Total System MVA							5.50			5.50	
Total Kinetic Energy							6.05			6.05	
Total Load							5.43			4.00	
Total Thermal Generation							4.00			4.00	
Total Renewable Generation							1.43			0.00	
Total Generation							5.43			4.00	
Excess Generation							0.00			0.00	
Total Up Regulation							0.40			0.40	
Total Down Regulation							3.40			3.40	
Legacy DG-PV	59.3Hz Capacity				0.81	59.3Hz Output		0.45	59.3Hz Output		0.58
	60.5Hz Capacity				2.02	60.5Hz Output		1.06	60.5Hz Output		1.64

Table O-137. Unit Commitment and Dispatch 2019

Table O-137 shows the unit commitment and dispatch schedules for the daytime and nighttime base case simulations.

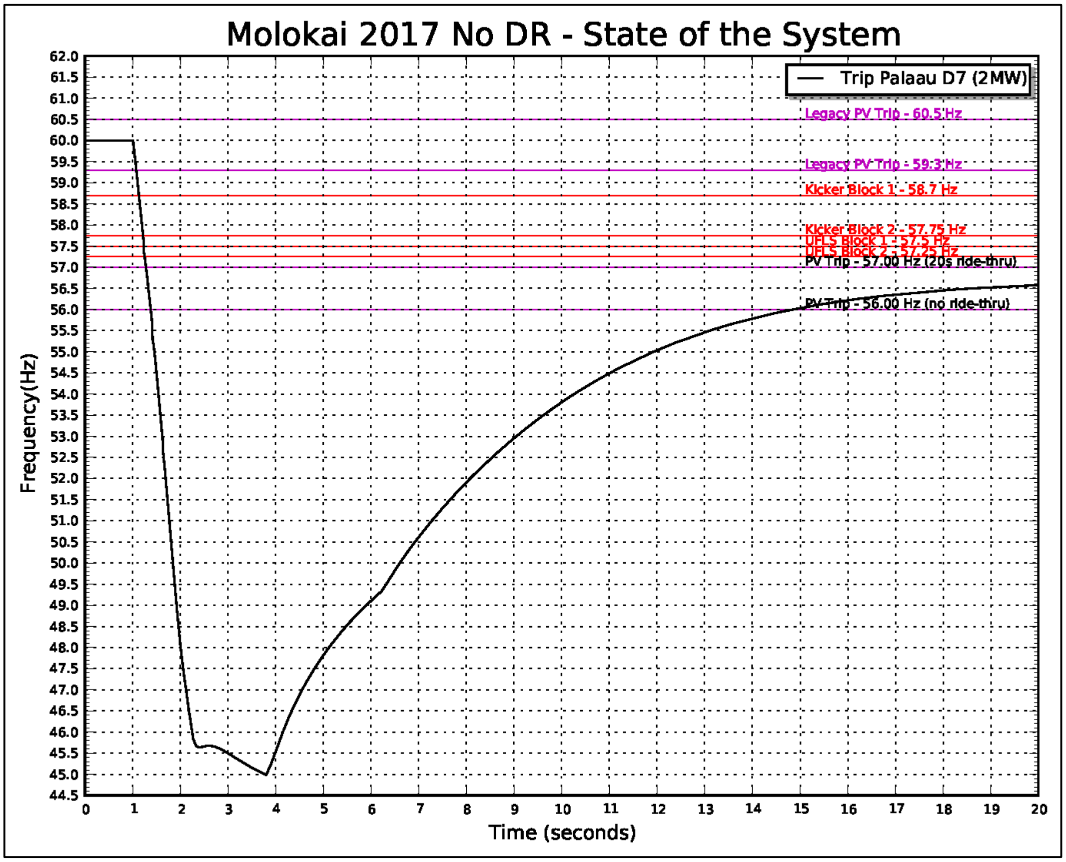

Figure O-316. Frequency Response Profile Day Base Case

Figure O-316 shows the frequency response profile for a Pala‘au 7 trip at 2.0 MW during the day. System kinetic energy is 6.1 MW-sec. The frequency breaches 45.0 Hz and two blocks of UFLS and two kicker blocks are required to stabilize system frequency.

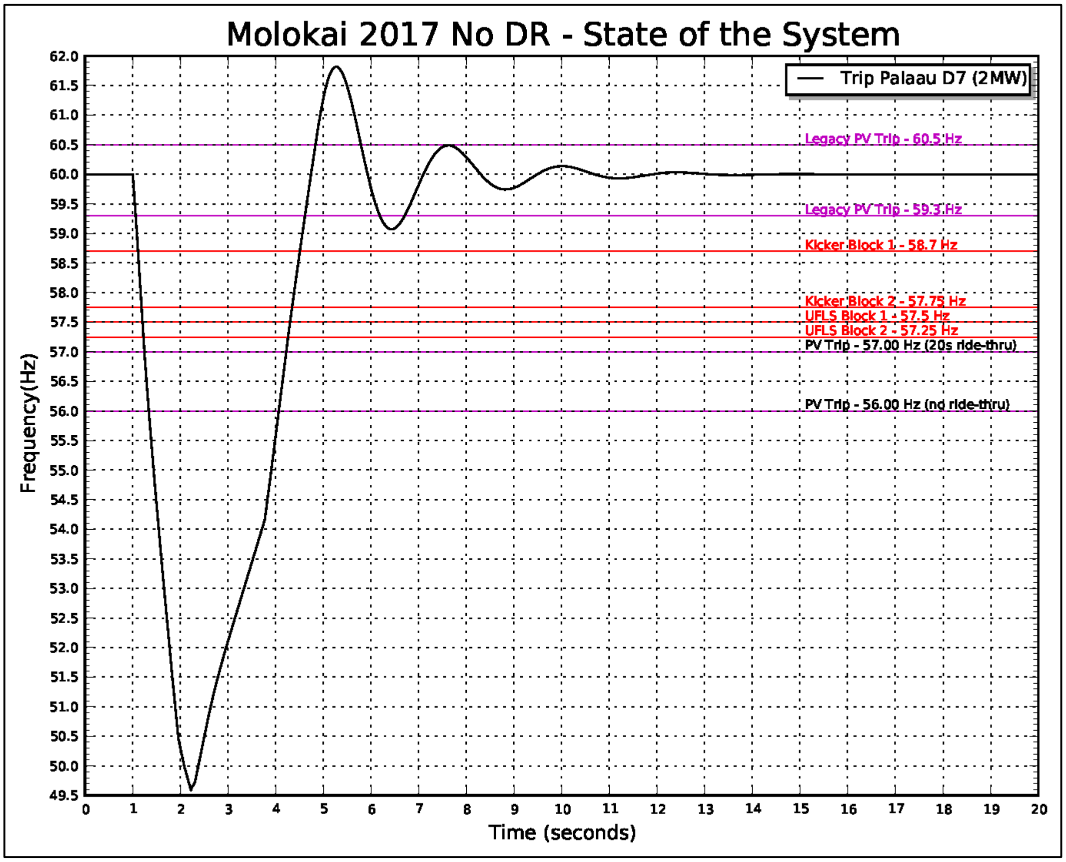

Figure O-317. Response Profile Night Base Case

Figure O-317 shows the frequency response profile for a Pala'au 7 trip at 2.0 MW during the night. System kinetic energy is 6.1 MW-sec. The frequency breaches 49.6 Hz and two blocks of UFLS are required to stabilize system frequency.

12kV Fault Simulation

Simulations were performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	Unit Ratings					Basecase - Fault Day		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70
PA D8	2.20	0.30	1.10	2.75	3.03	2.00	0.20	1.70
PA D9	2.20	0.30	1.10	2.75	3.03			
DG-PV	3.12	0.00				1.43		
Total System MVA							5.50	
Total Kinetic Energy							6.05	
Total Load							5.43	
Total Thermal Generation							4.00	
Total Renewable Generation							1.43	
Total Generation							5.43	
Excess Generation							0.00	
Total Up Regulation							0.40	
Total Down Regulation							3.40	
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.45
	60.5Hz Capacity			2.02		60.5Hz Output		1.06

Table O-138. Unit Commitment and Dispatch Fault Analysis 2017

Table O-138 shows the unit commitment and dispatch for the 12 kV fault analysis. Inverter-based generation is1.43 MW.

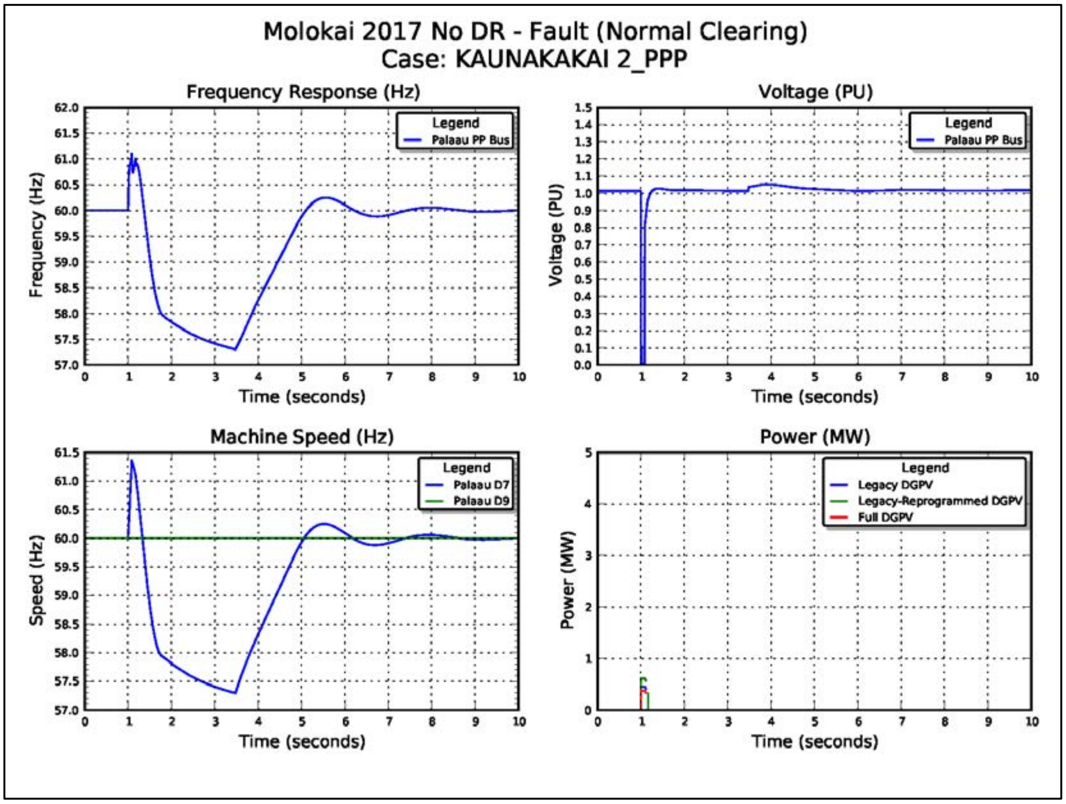

Figure O-318. System Performance Normally Cleared Fault

Figure O-318 shows the system performance for a normally cleared fault on the Kaunakakai 2 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 1.43 MW from inverter-based generation drops to zero, driving system frequency below 57.5 Hz. The system remains stable for all distribution circuit faults.

Post April DR Plan

System security analysis was performed on the Post April DR plan include loss of generation analysis and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

The Moloka'i system is a nominal 34.5/12 kV radial distribution system and does not fall under the jurisdiction of TPL-001. Distribution system reliability is driven by CAID and SAID indices as opposed to equivalent forced outage rate (EFOR). Therefore, the reliability criterion that was used for the frequency response analysis is to prevent system collapse and to maintain acceptable stability margin.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

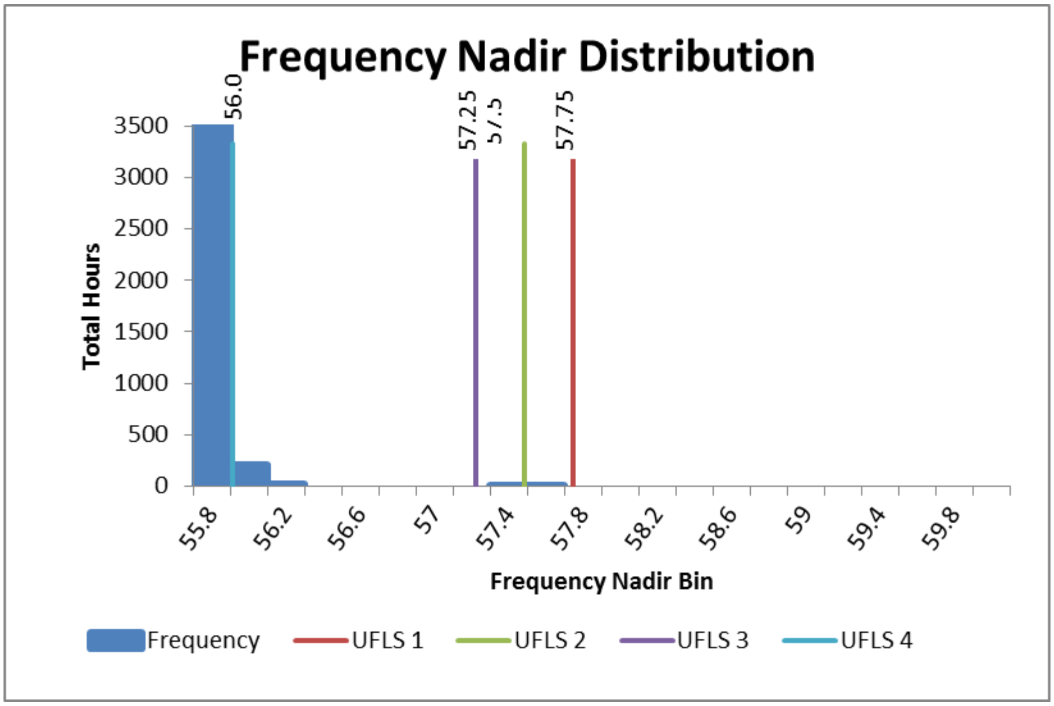

Figure O-319. Frequency Nadir Histogram 2019

Figure O-319 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 8736 hours was 4:00 PM on Saturday, March 13. The frequency nadir range for the boundary hour is > 56.0 Hz.

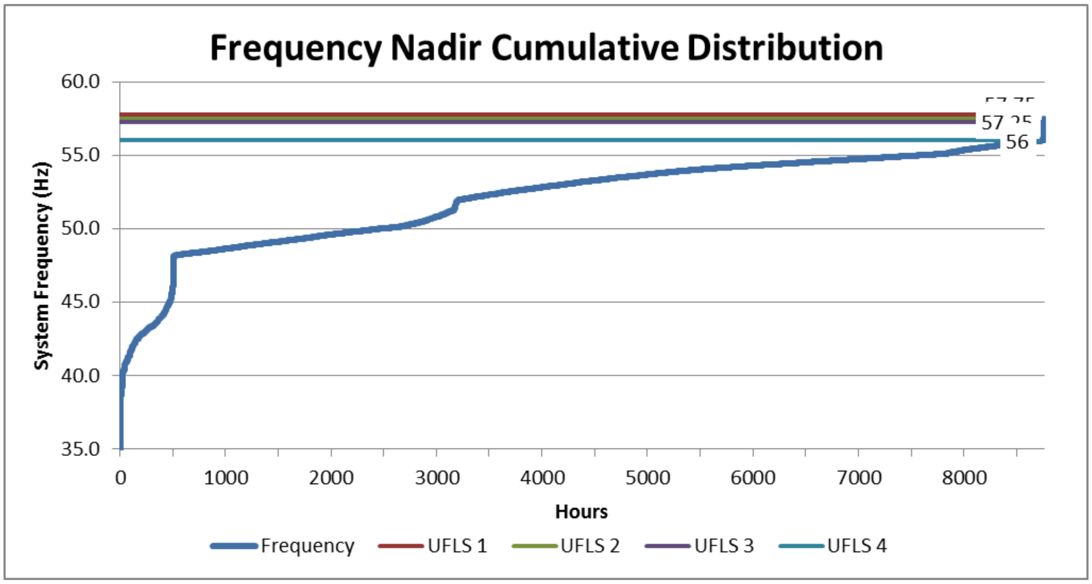

Figure O-320. Frequency Nadir Duration Curve 2019

Figure O-320 shows the frequency nadir duration curve for the resource plan in 2019. The system is at risk of deploying all four blocks of UFLS for 8736 hours of the year.

Unit	Unit Ratings					No DR - Palaau 9 Trip Boundary Mon 6/10/19 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	2.20	0.00	1.90
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
DG-PV	3.72	0.00				2.35		
Total System MVA							5.50	
Total Kinetic Energy							6.05	
Total Load							4.43	
Total Thermal Generation							2.20	
Total Renewable Generation							2.35	
Total Generation							4.55	
Excess Generation							0.12	
Total Up Regulation							0.00	
Total Down Regulation							1.90	
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.58
	60.5Hz Capacity			2.02		60.5Hz Output		1.64

Table O-139. Unit Commitment and Dispatch 2019

Table O-139 shows the unit commitment and dispatch for the boundary hour (6/10/19, 2:00 PM).

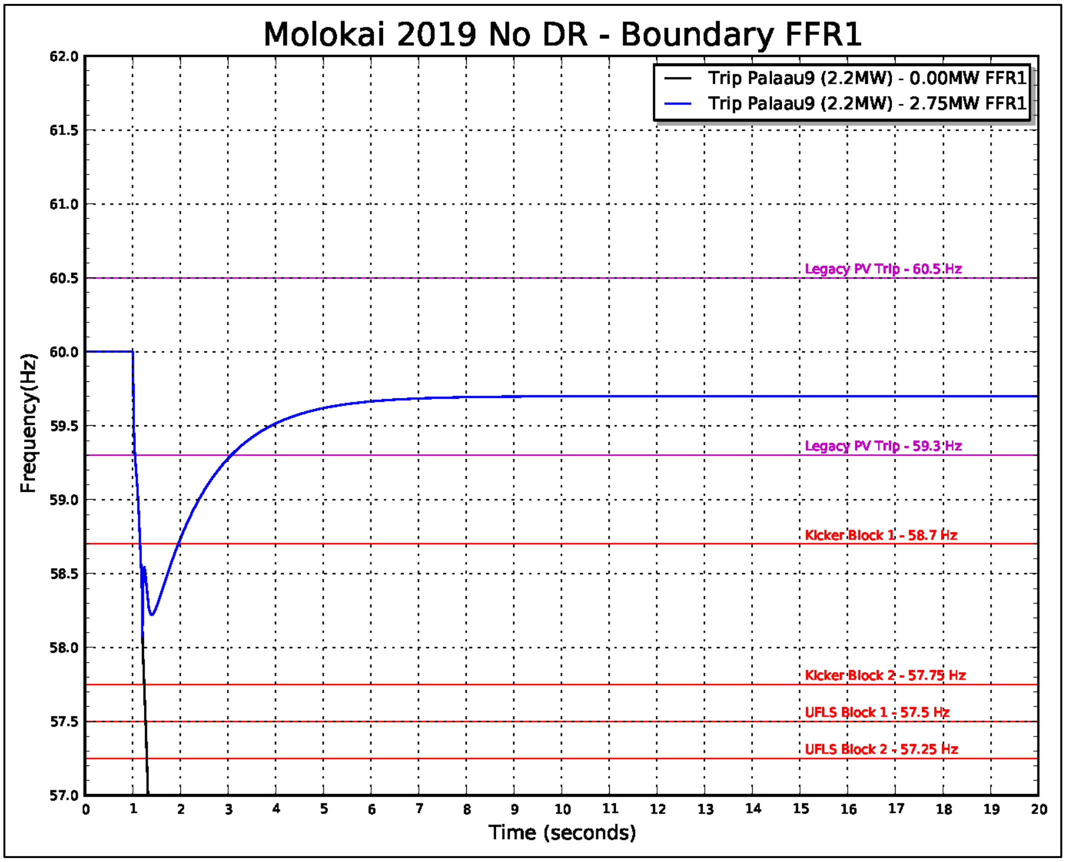

Figure O-321. Frequency Response Profile for FFR1

Figure O-321 shows the frequency response profile for a Pala'au 9 trip at 2.2 MW for a boundary hour. System kinetic energy is 6.1 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 580 kW. With no FFR, the system collapses. The capacity of FFR1 required to stabilize system frequency is 2.75 MW.

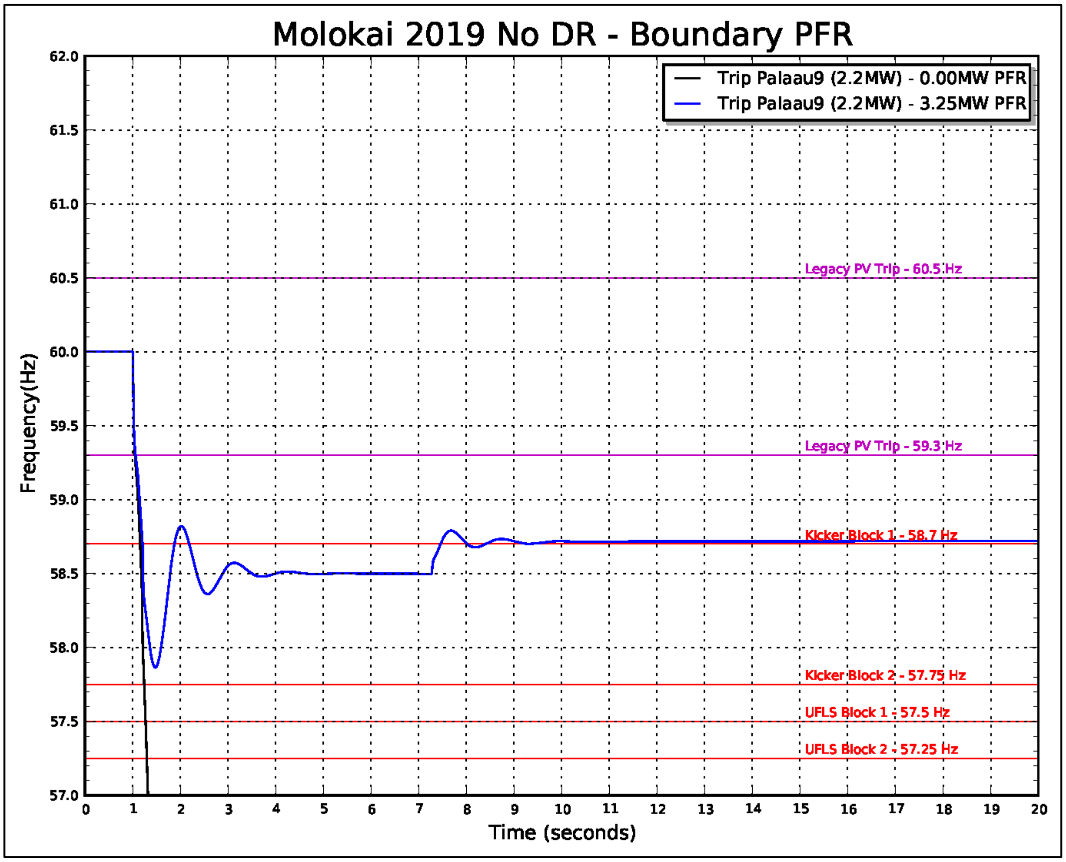

Figure O-322. Frequency Response Profile for PFR

Figure O-322 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	Unit Ratings					No DR - Fault Fri 6/21/19 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	1.52	0.68	1.22
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
DG-PV	3.72	0.00				2.53		
Total System MVA							5.50	
Total Kinetic Energy							6.05	
Total Load							4.05	
Total Thermal Generation							1.52	
Total Renewable Generation							2.53	
Total Generation							4.05	
Excess Generation							0.00	
Total Up Regulation							0.68	
Total Down Regulation							1.22	
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.65
	60.5Hz Capacity			2.02		60.5Hz Output		1.86

Table O-140. Unit Commitment and Dispatch Fault Analysis 2019

Table O-140 shows the unit commitment and dispatch for the 12 kV fault analysis. Inverter-based generation is 2.53 MW.

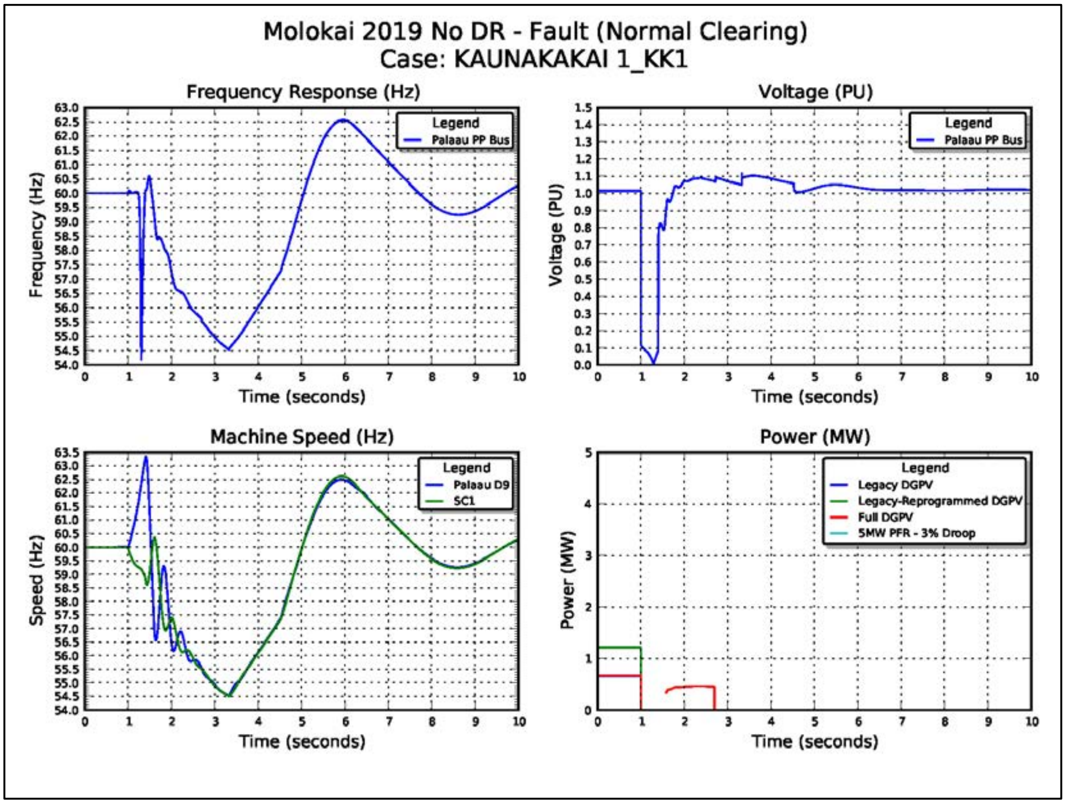

Figure O-323. System Performance Normally Cleared Fault

Figure O-323 shows the system performance for a normally cleared fault on the Kaunakakai 1 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 2.53 MW from inverter-based generation drops to zero, driving system frequency below 54.5.0 Hz. The system remains stable for all distribution circuit faults.

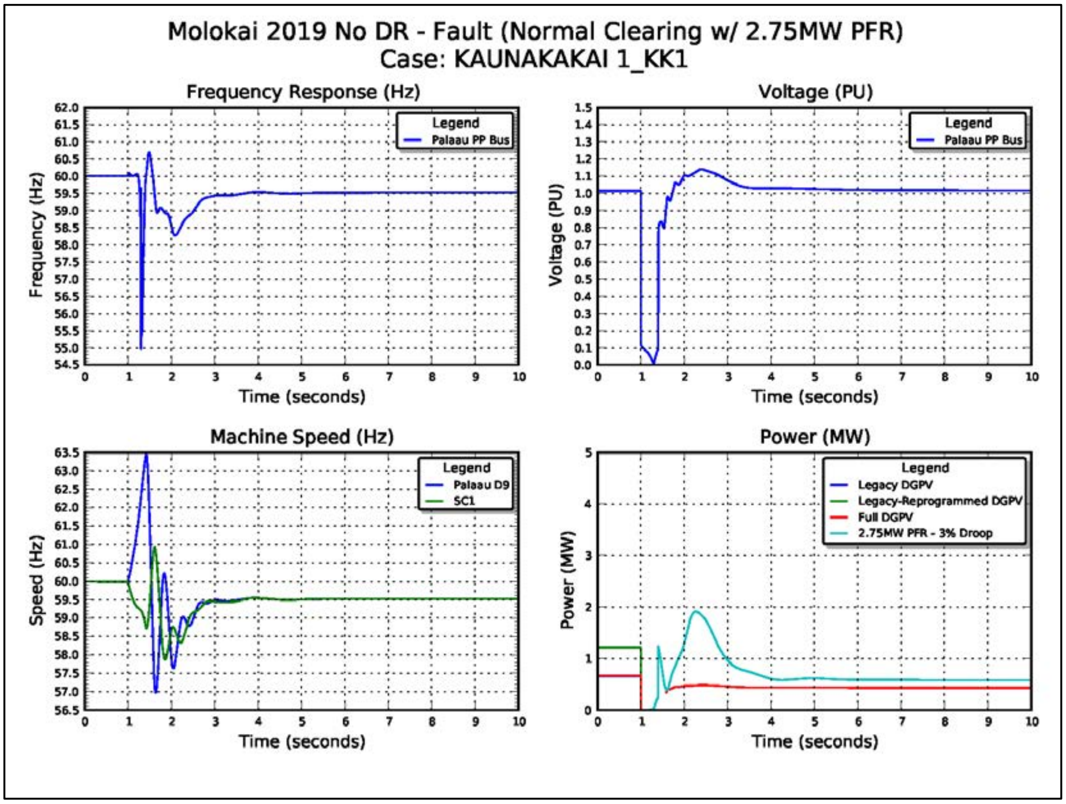

Figure O-324. Normally Cleared Fault Sensitivity PFR

Figure O-324 shows system performance with the addition of 2.75 MW PFR at 1 % droop response. For the purpose of this analysis, a BESS located at Pala'au.

The plot at the bottom right shows the frequency response from DG-PV and the 2.75 MW BESS. The aggregate response from synchronous units, BESS resources, the restoration of DG-PV generation, and four blocks of UFLS stabilizes system frequency.

2020

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

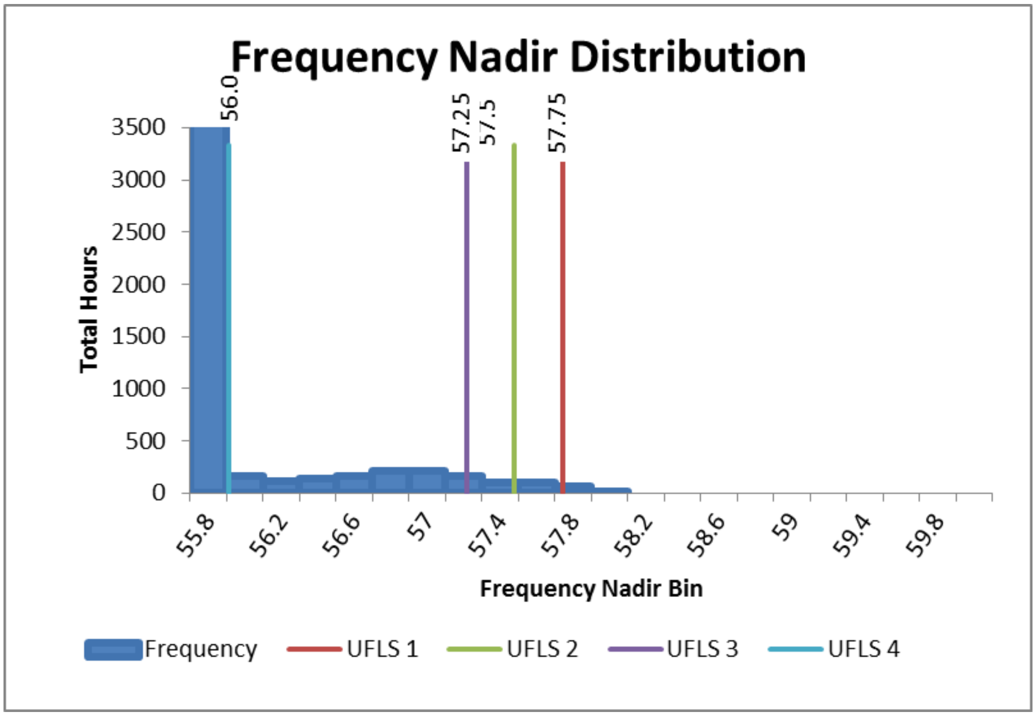

Figure O-325. Frequency Nadir Histogram

Figure O-325 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 7536 hours was 4:00 PM on Friday, February 21. The frequency nadir range for the boundary hour is > 56.0 Hz.

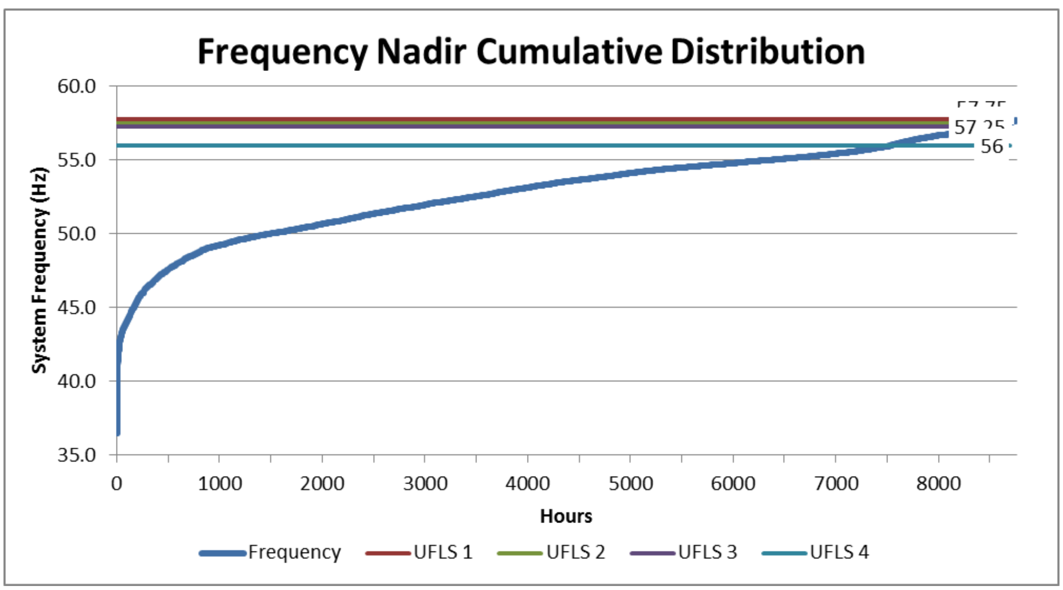

Figure O-326. Frequency Nadir Duration Curve

Figure O-326 shows the frequency nadir duration curve for the resource plan in 2020. The system is at risk of deploying all four blocks of UFLS for 7536 hours of the year.

<table>
<tr><th rowspan="2">Unit</th><th colspan="5">Unit Ratings</th><th colspan="3">No DR - Palaau 9 Trip Boundary Fri 2/21/20 Hour 16</th></tr>
<tr><th>Pmax</th><th>Pmin</th><th>Inertia H</th><th>Unit MVA</th><th>Unit K.E. (Mjoules)</th><th>Pgen</th><th>up reg (spin)</th><th>down reg</th></tr>
<tr><td>PALAAU1</td><td>1.25</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU2</td><td>1.25</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU3</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU4</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU5</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU6</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PA D7</td><td>2.20</td><td>0.30</td><td>1.10</td><td>2.75</td><td>3.03</td><td></td><td></td><td></td></tr>
<tr><td>PA D8</td><td>2.20</td><td>0.30</td><td>1.10</td><td>2.75</td><td>3.03</td><td></td><td></td><td></td></tr>
<tr><td>PA D9</td><td>2.20</td><td>0.30</td><td>1.10</td><td>2.75</td><td>3.03</td><td>2.12</td><td>0.08</td><td>1.82</td></tr>
<tr><td>SC1</td><td>0.00</td><td>0.00</td><td>2.00</td><td>2.75</td><td>3.03</td><td colspan="3">Synchronous Condenser</td></tr>
<tr><td>Wind1</td><td>2.50</td><td>0.00</td><td></td><td></td><td></td><td>0.01</td><td></td><td></td></tr>
<tr><td>Wind2</td><td>2.50</td><td>2.00</td><td></td><td></td><td></td><td>0.01</td><td></td><td></td></tr>
<tr><td>DG-PV</td><td>3.94</td><td>0.00</td><td></td><td></td><td></td><td>1.34</td><td></td><td></td></tr>
<tr><td colspan="6">Total System MVA</td><td colspan="3">5.50</td></tr>
<tr><td colspan="6">Total Kinetic Energy</td><td colspan="3">6.05</td></tr>
<tr><td colspan="6">Total Load</td><td colspan="3">3.48</td></tr>
<tr><td colspan="6">Total Thermal Generation</td><td colspan="3">2.12</td></tr>
<tr><td colspan="6">Total Renewable Generation</td><td colspan="3">1.36</td></tr>
<tr><td colspan="6">Total Generation</td><td colspan="3">3.48</td></tr>
<tr><td colspan="6">Excess Generation</td><td colspan="3">0.00</td></tr>
<tr><td colspan="6">Total Up Regulation</td><td colspan="3">0.08</td></tr>
<tr><td colspan="6">Total Down Regulation</td><td colspan="3">1.82</td></tr>
<tr><td rowspan="2">Legacy DG-PV</td><td colspan="3">59.3Hz Capacity</td><td colspan="2">0.81</td><td colspan="2">59.3Hz Output</td><td>0.33</td></tr>
<tr><td colspan="3">60.5Hz Capacity</td><td colspan="2">2.02</td><td colspan="2">60.5Hz Output</td><td>0.95</td></tr>
</table>

Table O-141. Unit Commitment and Dispatch 2020

Table O-141 shows the unit commitment and dispatch for the boundary hour (2/21/20, 4:00 PM).

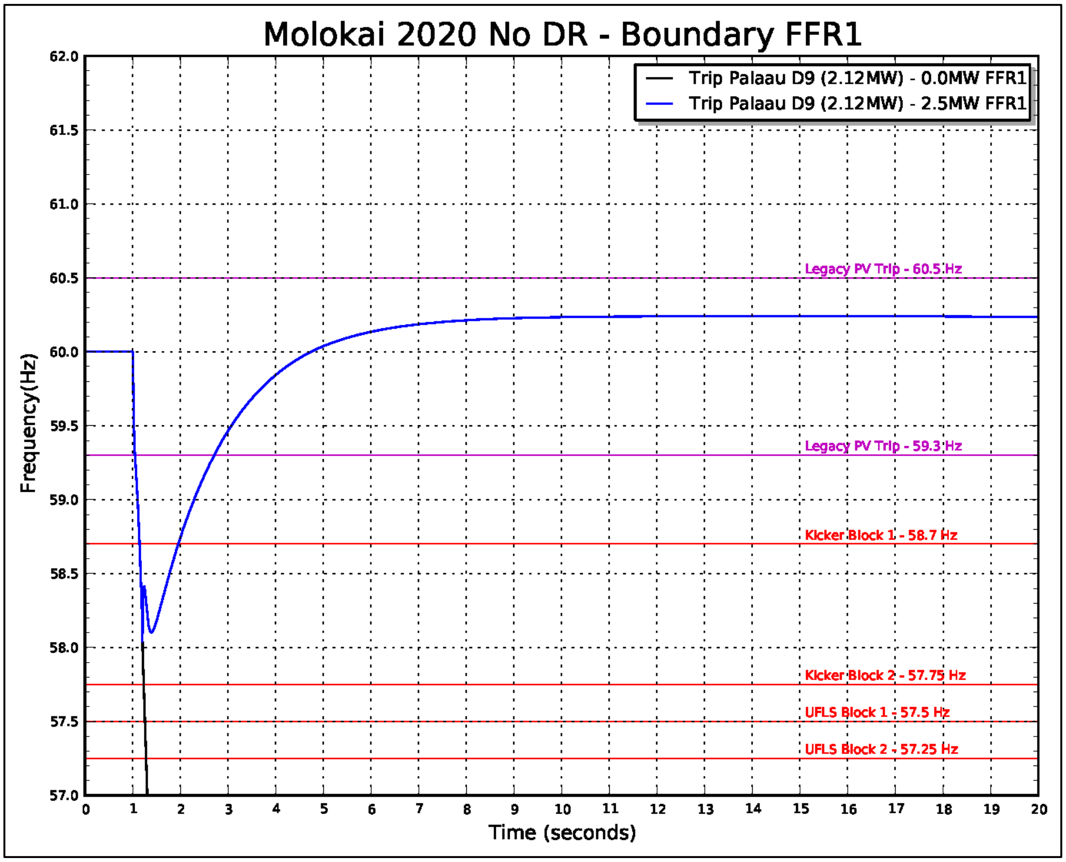

Figure O-327. Frequency Response Profile for FFR1

Figure O-327 shows the frequency response profile for a Pala'au 9 trip at 2.12 MW for a boundary hour. System kinetic energy is 6.1 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 330 kW. With no FFR, the system collapses. The capacity of FFR1 required to stabilize system frequency is 2.5 MW.

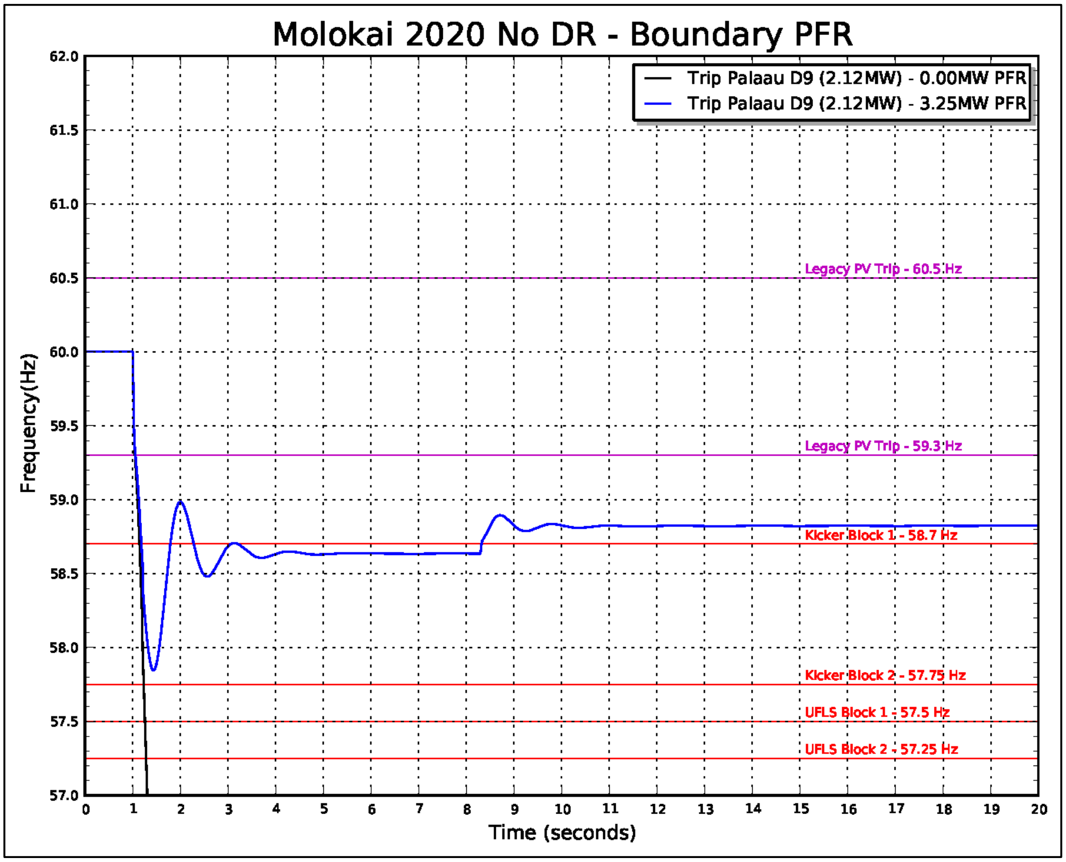

Figure O-328. Frequency Response Profile for PFR

Figure O-328 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

12kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

Unit	Unit Ratings					No DR - Fault Sun 6/21/20 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03			
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.50	0.00				0.72		
Wind2	2.50	2.00				0.72		
DG-PV	3.94	0.00				2.63		
Total System MVA						2.75		
Total Kinetic Energy						3.03		
Total Load						4.07		
Total Thermal Generation						0.00		
Total Renewable Generation						4.07		
Total Generation						4.07		
Excess Generation						0.00		
Total Up Regulation						0.00		
Total Down Regulation						0.00		
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.65
	60.5Hz Capacity			2.02		60.5Hz Output		1.86

Table O-142. Unit Commitment and Dispatch Fault Analysis 2020

Table O-142 shows the unit commitment and dispatch for the 12 kV fault analysis. Inverter-based generation is 2.63 MW.

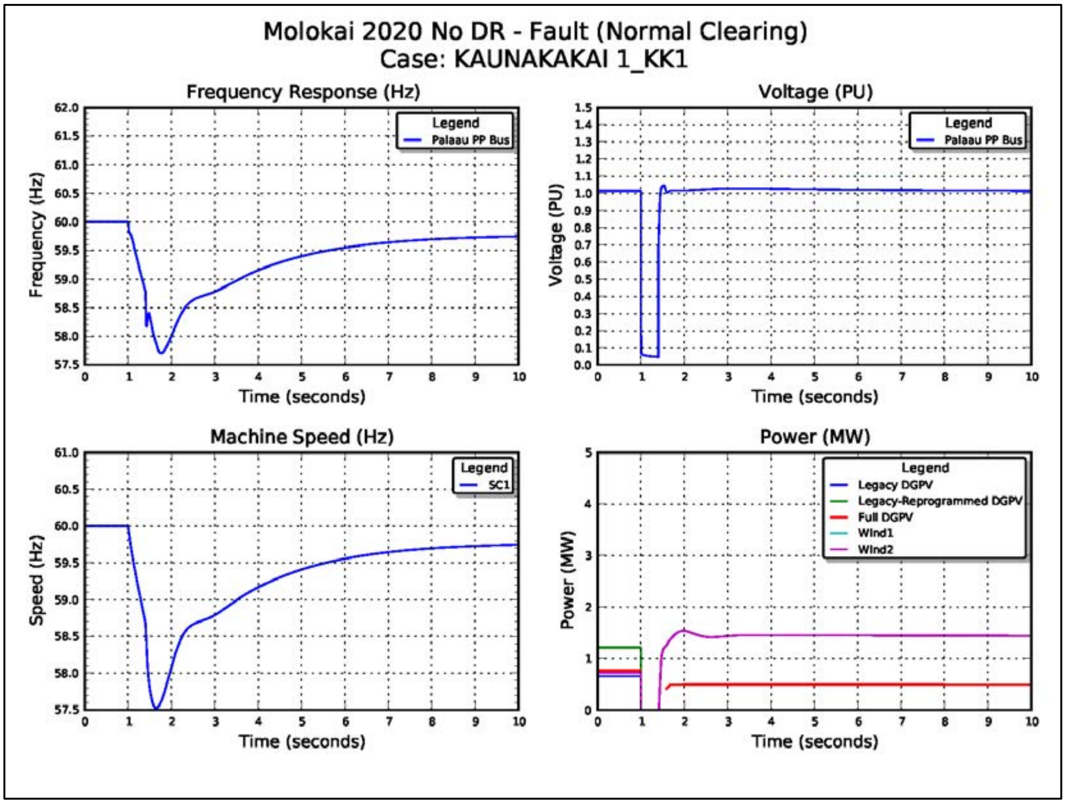

Figure O-329. System Performance Normally Cleared Fault

Figure O-329 shows the system performance for a normally cleared fault on the Kaunakakai 1 distribution circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold where the 2.53 MW from inverter-based generation drops to zero, driving system frequency below 54.5.0 Hz. The system remains stable for all distribution circuit faults.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

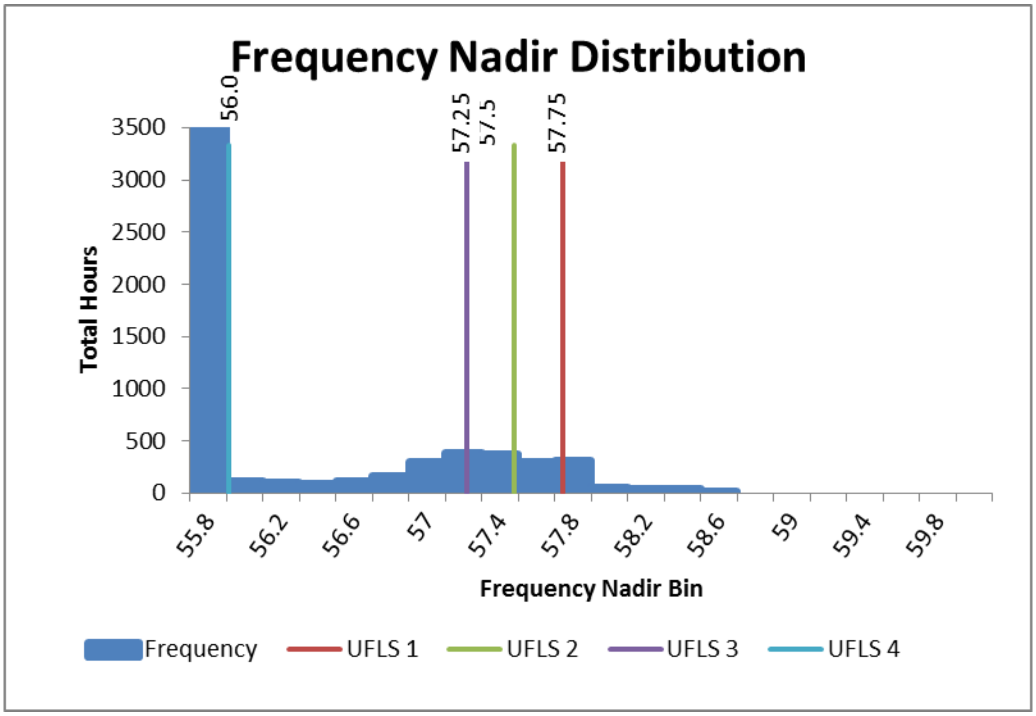

Figure O-330. Frequency Nadir Histogram 2030

Figure O-330 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 6516 hours was 3:00 PM on Tuesday, December 24. The frequency nadir range for the boundary hour is > 56.0 Hz.

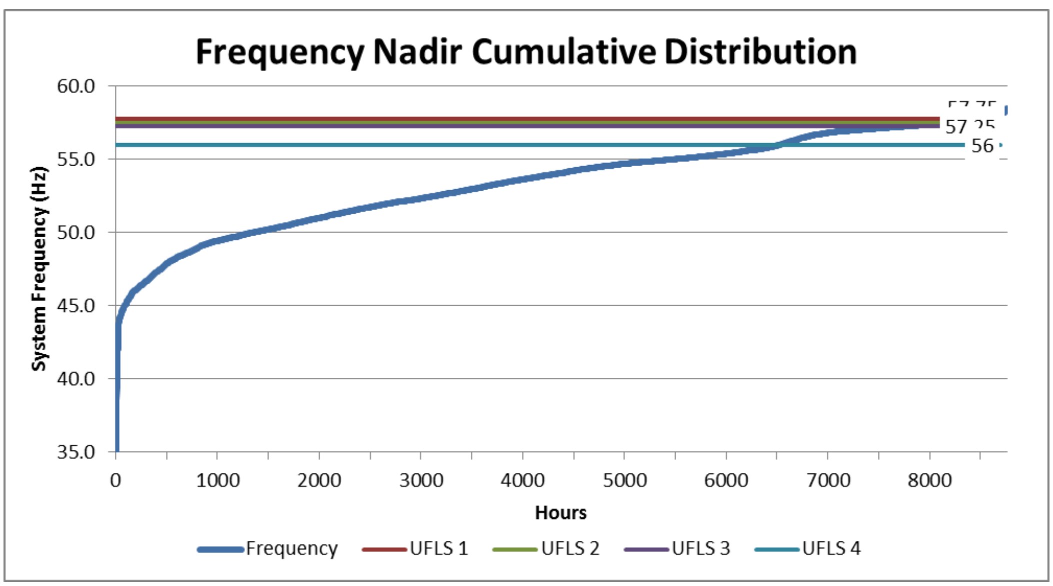

Figure O-331. Frequency Nadir Duration Curve 2030

Figure O-331 shows the frequency nadir duration curve for the resource plan in 2030. The system is at risk of deploying all four blocks of UFLS for 6516 hours of the year.

<table>
<tr><th rowspan="2">Unit</th><th colspan="5">Unit Ratings</th><th colspan="3">No DR - Paalau 9 Trip Boundary
Tues 12/24/30 Hour 15</th></tr>
<tr><th>Pmax</th><th>Pmin</th><th>Inertia H</th><th>Unit MVA</th><th>Unit K.E. (Mjoules)</th><th>Pgen</th><th>up reg (spin)</th><th>down reg</th></tr>
<tr><td>PALAAU1</td><td>1.25</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU2</td><td>1.25</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU3</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU4</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU5</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PALAAU6</td><td>0.97</td><td>0.31</td><td>0.34</td><td>1.25</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>PA D7</td><td>2.20</td><td>0.30</td><td>1.10</td><td>2.75</td><td>3.03</td><td></td><td></td><td></td></tr>
<tr><td>PA D8</td><td>2.20</td><td>0.30</td><td>1.10</td><td>2.75</td><td>3.03</td><td></td><td></td><td></td></tr>
<tr><td>PA D9</td><td>2.20</td><td>0.30</td><td>1.10</td><td>2.75</td><td>3.03</td><td>2.16</td><td>0.04</td><td>1.86</td></tr>
<tr><td>SC1</td><td>0.00</td><td>0.00</td><td>2.00</td><td>2.75</td><td>3.03</td><td colspan="3">Synchronous Condenser</td></tr>
<tr><td>Wind1</td><td>2.50</td><td>0.00</td><td></td><td></td><td></td><td>0.00</td><td></td><td></td></tr>
<tr><td>Wind2</td><td>2.50</td><td>0.00</td><td></td><td></td><td></td><td>0.00</td><td></td><td></td></tr>
<tr><td>DG-PV</td><td>6.13</td><td>0.00</td><td></td><td></td><td></td><td>1.90</td><td></td><td></td></tr>
<tr><td colspan="6">Total System MVA</td><td colspan="3">5.50</td></tr>
<tr><td colspan="6">Total Kinetic Energy</td><td colspan="3">6.05</td></tr>
<tr><td colspan="6">Total Load</td><td colspan="3">4.05</td></tr>
<tr><td colspan="6">Total Thermal Generation</td><td colspan="3">2.16</td></tr>
<tr><td colspan="6">Total Renewable Generation</td><td colspan="3">1.90</td></tr>
<tr><td colspan="6">Total Generation</td><td colspan="3">4.06</td></tr>
<tr><td colspan="6">Excess Generation</td><td colspan="3">0.01</td></tr>
<tr><td colspan="6">Total Up Regulation</td><td colspan="3">0.04</td></tr>
<tr><td colspan="6">Total Down Regulation</td><td colspan="3">1.86</td></tr>
<tr><td rowspan="2">Legacy DG-PV</td><td colspan="3">59.3Hz Capacity</td><td colspan="2">0.81</td><td colspan="2">59.3Hz Output</td><td>0.33</td></tr>
<tr><td colspan="3">60.5Hz Capacity</td><td colspan="2">2.02</td><td colspan="2">60.5Hz Output</td><td>0.93</td></tr>
</table>

Table O-143. Unit Commitment and Dispatch 2030

Table O-143 shows the unit commitment and dispatch for the boundary hour (12/24/30, 3:00 PM).

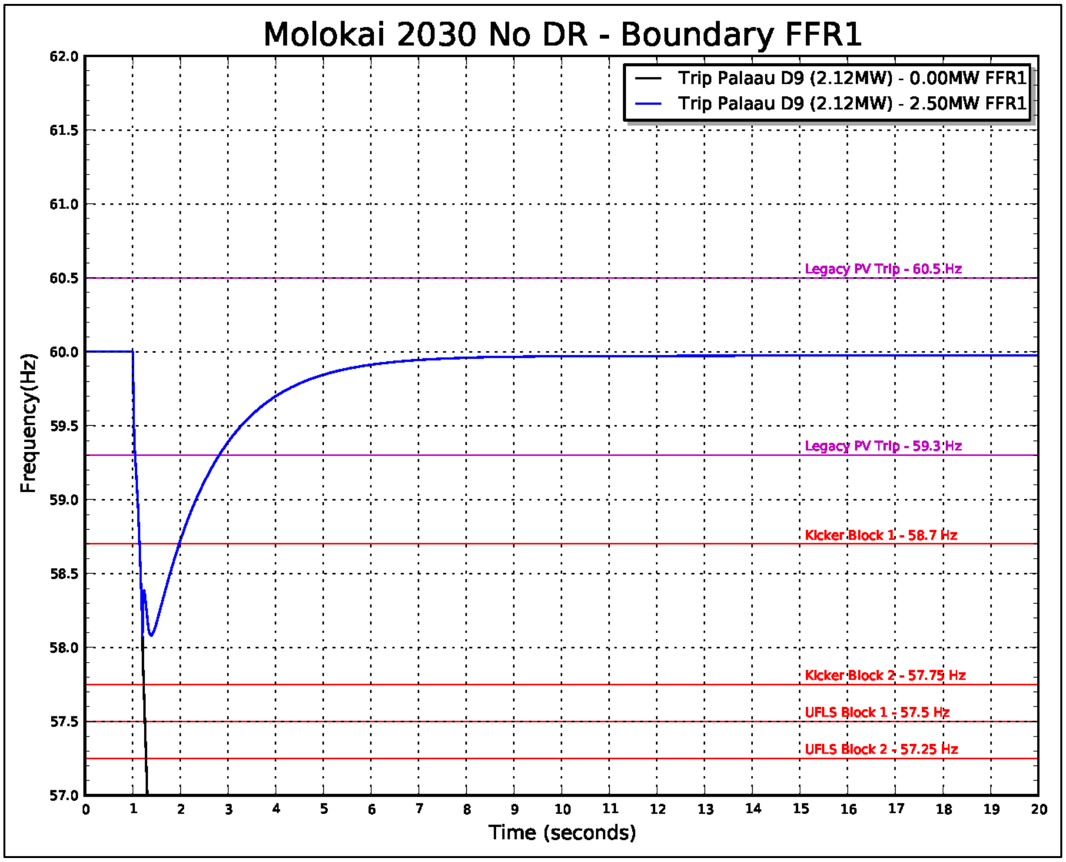

Figure O-332. Frequency Response Profile for FFR1

Figure O-332 shows the frequency response profile for Pala'au 9 trip at 2.12 MW for a boundary hour. System kinetic energy is 6.1 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 330 kW. With no FFR, the frequency nadir breaches 57.9 Hz and two blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to stabilize system frequency is 2.5 MW.

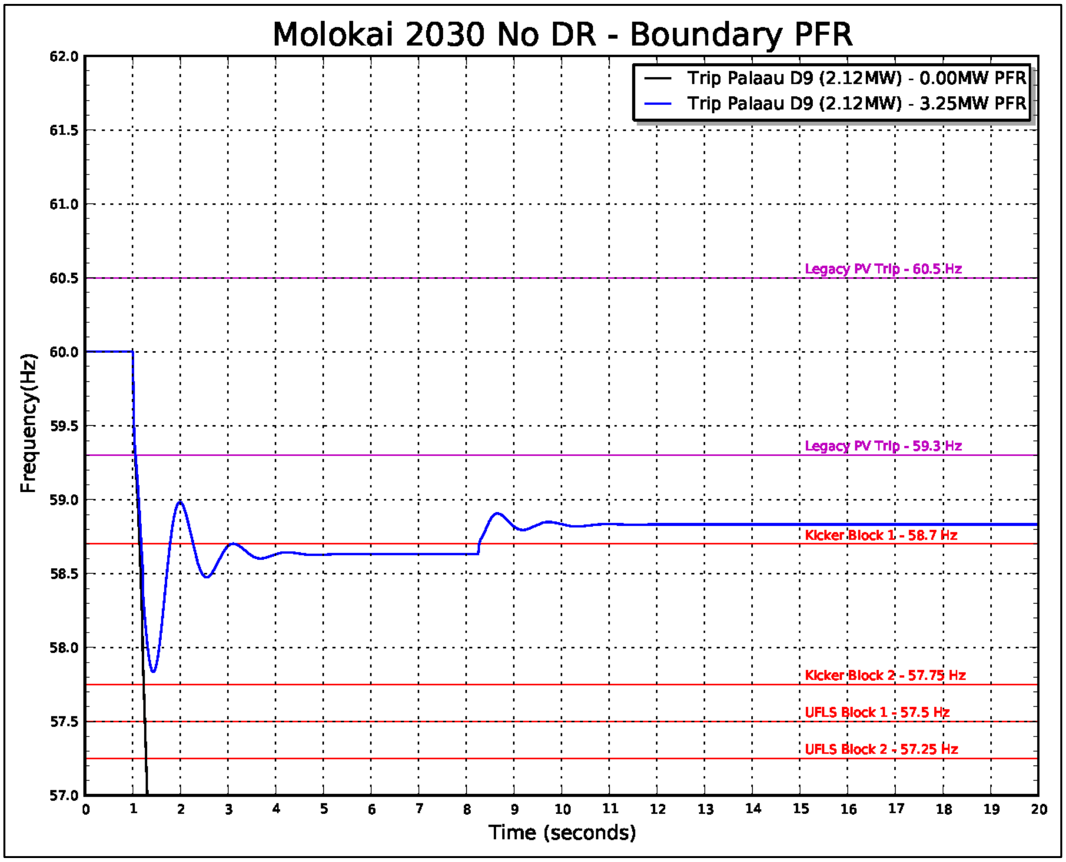

Figure O-333. Frequency Response Profile for PFR

Figure O-333 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected from the production simulation data to represent a boundary condition.

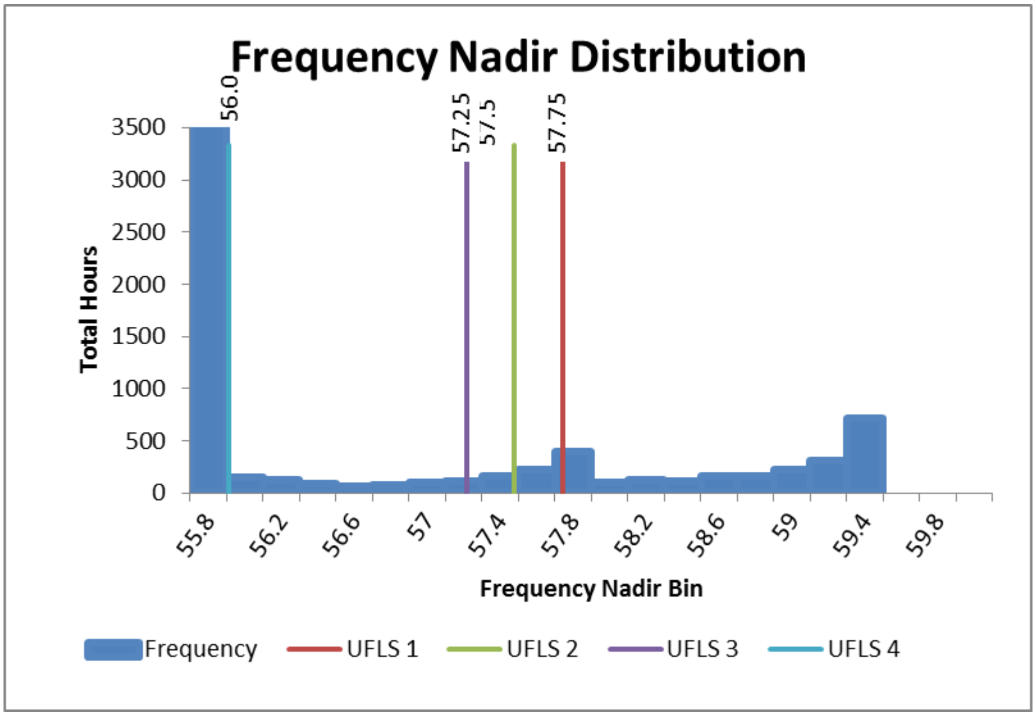

Figure O-334. Frequency Nadir Histogram 2045

Figure O-334 shows the frequency nadir histogram for the entire year. The boundary hour selected from a minimum distribution of 5509 hours was 5:00 AM on Thursday, February 16. The frequency nadir range for the boundary hour is > 56.0 Hz.

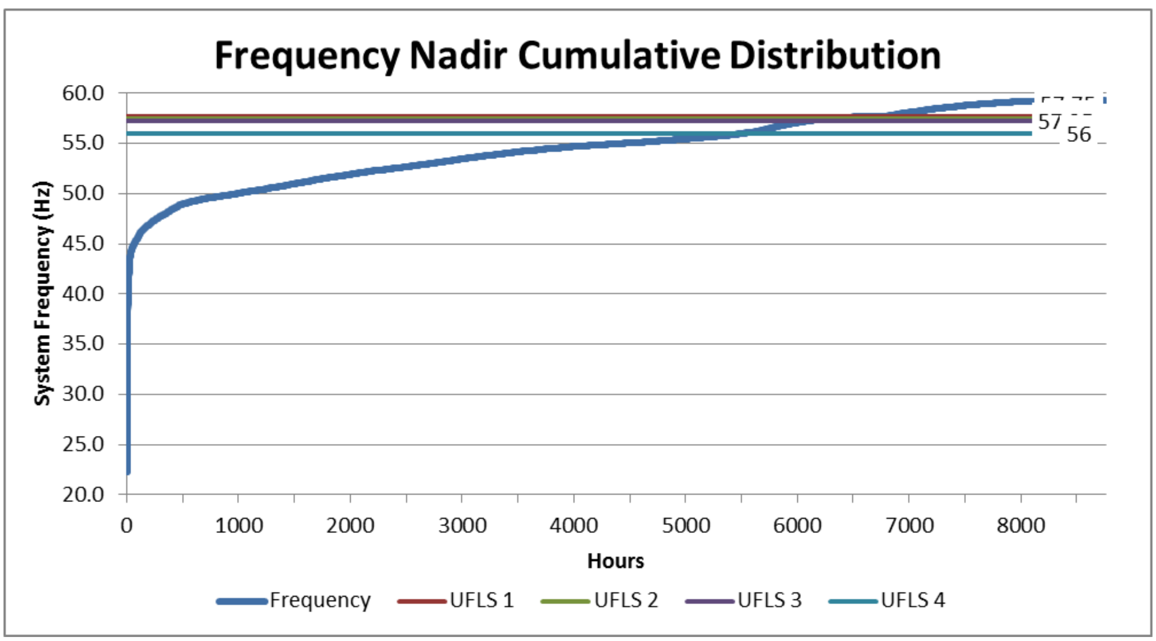

Figure O-335. Frequency Nadir Duration Curve 2045

Figure O-335 shows the frequency nadir duration curve for the resource plan in 2045. The system is at risk of deploying all four blocks of UFLS for 5509 hours of the year.

Unit	Unit Ratings					No DR - Palaau 9 trip Boundary Thurs 2/16/45 Hour 5		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E. (Mjoules)	Pgen	up reg (spin)	down reg
PALAAU1	1.25	0.31	0.34	1.25	0.43			
PALAAU2	1.25	0.31	0.34	1.25	0.43			
PALAAU3	0.97	0.31	0.34	1.25	0.43			
PALAAU4	0.97	0.31	0.34	1.25	0.43			
PALAAU5	0.97	0.31	0.34	1.25	0.43			
PALAAU6	0.97	0.31	0.34	1.25	0.43			
PA D7	2.20	0.30	1.10	2.75	3.03			
PA D8	2.20	0.30	1.10	2.75	3.03			
PA D9	2.20	0.30	1.10	2.75	3.03	2.12	0.08	1.82
SC1	0.00	0.00	2.00	2.75	3.03	*Synchronous Condenser*		
Wind1	2.50	0.00				0.00		
Wind2	2.50	0.00				0.00		
DG-PV	9.41	0.00				0.00		
Total System MVA							5.50	
Total Kinetic Energy							6.05	
Total Load							2.12	
Total Thermal Generation							2.12	
Total Renewable Generation							0.00	
Total Generation							2.12	
Excess Generation							0.00	
Total Up Regulation							0.08	
Total Down Regulation							1.82	
Legacy DG-PV	59.3Hz Capacity			0.81		59.3Hz Output		0.00
	60.5Hz Capacity			2.02		60.5Hz Output		0.00

Table O-144. Unit Commitment and Dispatch 2045

Table O-144 shows the unit commitment and dispatch for the boundary hour (2/16/45, 5:00 AM).

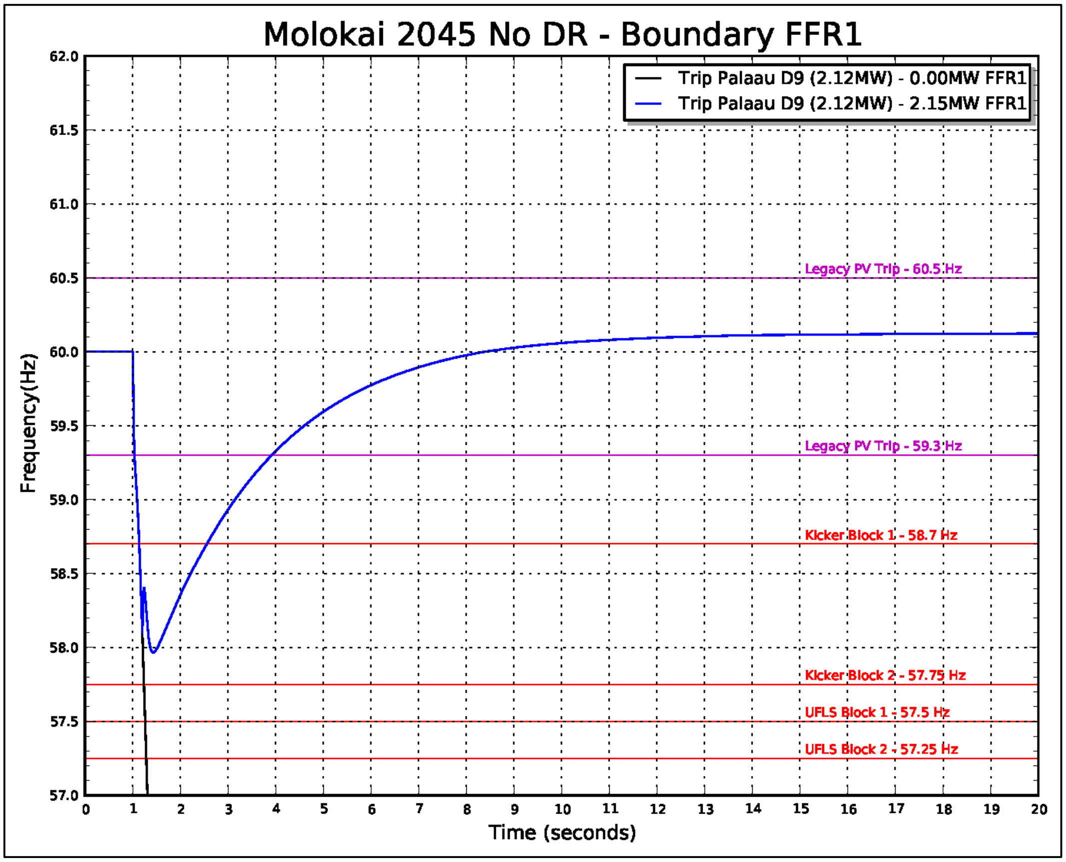

Figure O-336. Frequency Response Profile for FFR1

Figure O-336 shows the frequency response profile for a Pala'au 9 trip at 2.12 MW for a boundary hour.. System kinetic energy is 6.1 MW-sec. The capacity of FFR1 required to stabilize system frequency is 2.15 MW.

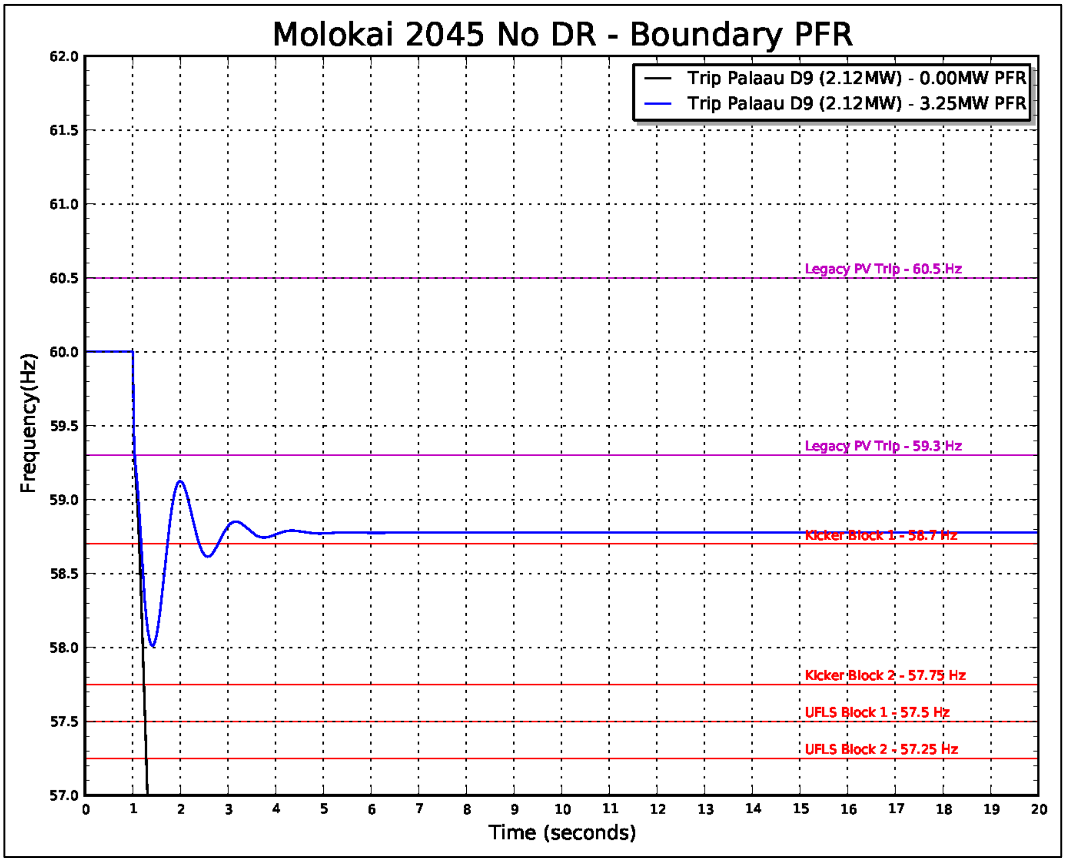

Figure O-337. Frequency Response Profile for PFR

Figure O-337 shows the frequency response profile for the PFR analysis. The PFR capacity required to stabilize system frequency is 3.25 MW.

Moloka'i Summary

The system security analysis determines technology-neutral requirements for as single resource plan to ensure the system is stable and maintains an acceptable stability margin. Moloka'i is a nominal 34.5/12 kV radial distribution system that does not fall under the jurisdiction of TPL-001. System security analyses includes loss of generation analysis and fault analysis for years 2019-2020. Moloka'i is scheduled to achieve 100% RPS by 2020 so loss of generation contingency analysis was also performed for select years beyond 2020.

Minimum Fault Current

The Moloka'i distribution system requires 2.75 MVA of fault current to ensure operation of protective relay schemes. A new 2.75 MVA synchronous condenser is required in 2019 to meet minimum fault current requirements.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to maintain system stability. One hour was selected to represent a boundary condition. Table O-206 (page O-617) shows the results of this analysis.

The system is at risk for instability in 2019. Analysis indicates 2.75 MW of FFR1 or PFR is required to stabilize system frequency for a loss of generation contingency.

12kV Fault Analysis

Analysis was performed to determine the island-wide system impacts of electrical faults on the distribution system. An electrical fault close to Miki Basin is the most severe system disturbance that is typically characterized by high system frequency and low voltages until the fault can be isolated. A fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system. Faults that are close to Miki Basin are cleared in 5-cycles and faults at the end of the circuit is cleared in 24-cycles.

The system remains stable for normally cleared faults on any distribution circuit so no sensitivity analyses were performed.

HAWAIʻI ISLAND SYSTEM SECURITY ANALYSIS

State of the System

The Hawaiʻi system does not meet the requirement of TPL-001 for loss of generation contingency events so FFR analysis are performed for 2019.

The island of Hawaiʻi has the highest penetration of renewable resources in the nation and the system often operates with the minimum must-run units for system security. In addition to the frequency stability issues that face Oʻahu and Maui, characteristics of the Hawaiʻi transmission system increases the exposure to electrical faults. The Hawaiʻi transmission system covers a very large territory and has approximately 640 miles of 69 kV transmission lines. In addition, most of the generation is on the east side of the island while the load center is in the west. This makes the Hawaiʻi Electric Light system more susceptible to steady state and transient voltage instability.

Minimum Fault Current

A minimum fault current analysis was not performed for this PSIP. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Hawaiʻi system requires 80 MVA of which 25 MVA must be connected on the West side of the island. This requirement presumes protective relay schemes are currently operating as designed. This does not ensure the system has sufficient fault current to meet transient voltage stability requirements. More analysis is required to ensure protective relay schemes are operational and transient voltage stability is maintained.

Historical Contingency Events

Date/Time	Line	Type of Fault	Lowest Voltages at Keahole (A /B /C phase)	Load Loss (MW)	Frequency Peak
Sun 8/23/15 0055 hrs	7500/9300	2-Line-Gnd	0.28pu / 0.26pu / 0.79pu	17	60.68
Sun 8/23/15 1455 hrs	8100/8200	3-phase	0.44pu / 0.46pu / 0.42pu	17	60.41
Sun 8/23/15 1502 hrs	6800	3-phase	0.43pu / 0.43pu / 0.45pu	10	60.2
Sun 8/23/15 1541 hrs	6200	3-phase	0.45pu/ 0.45pu / 0.45pu	14	60.28
Wed 9/2/15 1605 hrs	7100	3-phase	0.33pu / 0.37pu / 0.34pu	20	60.43
Thu 9/3/15 1454 hrs	8100/8200	3-phase	0.41pu / 0.43pu / 0.41pu	18	60.41
Sun 9/13/15 1541 hrs	7100	A-Gnd	0.61pu / 0.86pu / 0.61pu	5	60.17
Sun 9/13/15 1641 hrs	7100	3-phase	0.28pu / 0.30pu / 0.28pu	17	60.32
Tue 9/15/15 1733hrs	7500/9300	A-Gnd	0.26pu / 0.68pu / 0.66pu	20	60.5

Table O-145. Hawai'i Electric Light Historic Transmission Faults

Table O-145 shows some of the more severe electrical faults on the 69 kV transmission system that illustrates the increase exposure to multi-phase electrical faults that can trigger loss of load. Therefore, fault simulations will be included in the analysis to bring the system into compliance with TPL-001.

Hawai'i relies on under frequency load shedding for frequency response reserves for N-1 loss of generation contingency events. Hawai'i Electric Light has implemented a dynamic UFLS scheme to meet the requirements specified in TPL-001 that allows 15% of the system load to be shed on single loss of generation contingency events.

Block	Setpoint (Hz)	df/dt	% System Net Demand
1	59.1	0.5 Hz/sec	5%
2	58.8	0.5 Hz/sec	10%
3	58.5	N/A	10%
4	58.2	N/A	15%
5	57.9	N/A	10%
6	57.6	N/A	20%
Kicker Block	59.3	N/A	5 MW

Table O-146. Hawai'i Electric Light Dynamic UFLS

Table O-146 shows the capacities of the UFLS scheme. The dynamic UFLS scheme allows Blocks 1 and 2 to be initiated on df/dt settings for severe loss of generation contingency events; or by frequency set points for less severe contingencies but in most instances, the df/dt relays are activated. The dynamic UFLS scheme continuously monitors distribution circuit loads such that Blocks 1 and 2 will meet the 15% load shed requirement established by TPL-001.

2017

Loss of Generation Simulation

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

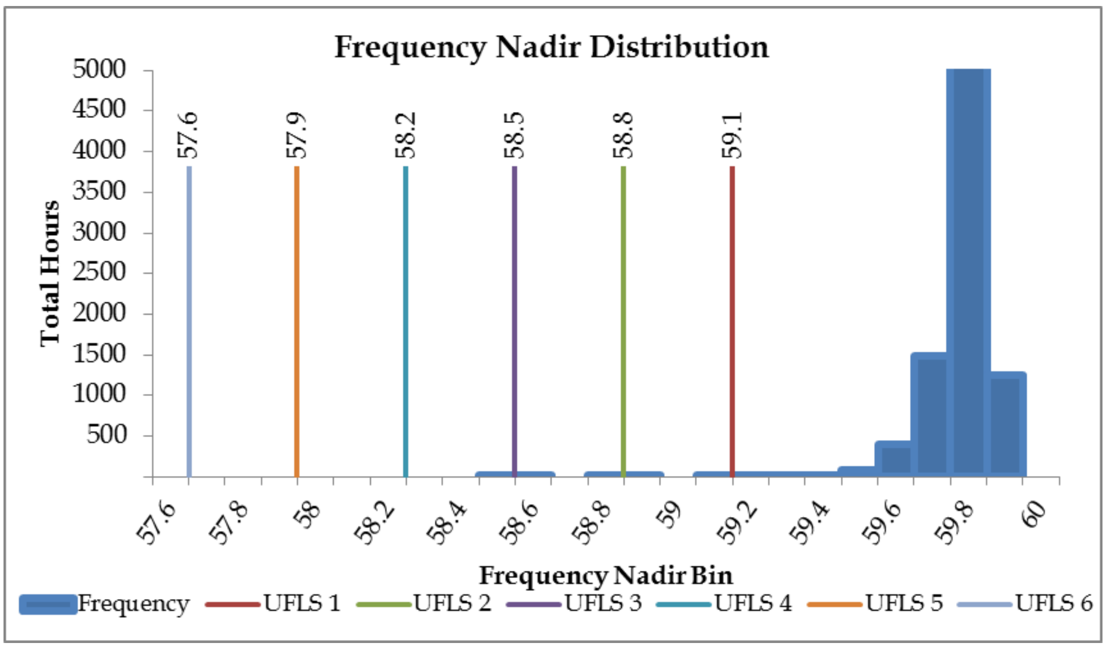

Figure O-338. Frequency Nadir Histogram 2017

Figure O-338 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour selected from a minimum distribution of 4 hours was 3:00 AM on Saturday, June 22. The frequency nadir range for the boundary hour is 58.4 – 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

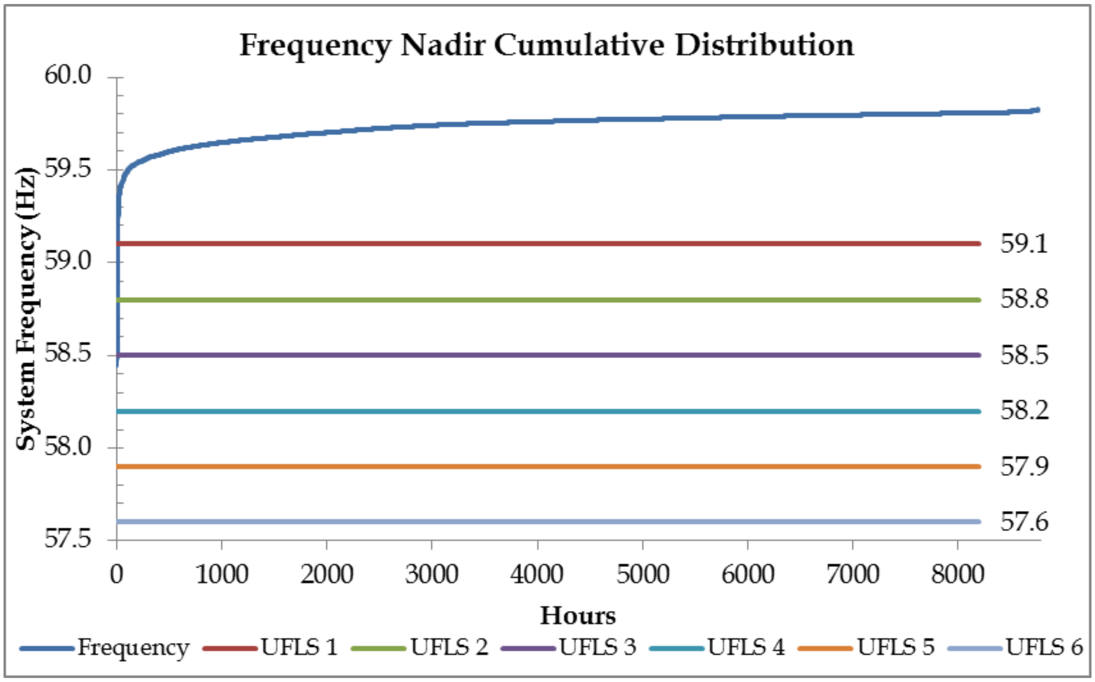

Figure O-339. Frequency Nadir Distribution Curve 2017

Figure O-339 shows the frequency nadir duration curve for the resource plan in 2017. The system is at risk of exceeding the UFLS requirements of TPL-001 for 4 hours of the year.

Unit	Unit Ratings					Theme 3 - Keahole STCC Trip Boundary Sat 6/22/19 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.9	1.1	14.9
Keahole STCC	25.0	7.0	3.13	46.5	146	24.0	1.0	17.0
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	12.8	0.7	7.8
Hill 6	20.5	8.0	2.53	27.5	70	19.5	1.0	11.5
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.5		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	0.5		
Apollo	20.5	0.0				3.1		
HRD	10.5	0.0				1.9		
Hydro	16.8	0				3		
Wind	31.0	0				5		
DG-PV	122.5	0						
Total Kinetic Energy						460		
Total Load						101		
Total Thermal Generation						93		
Total Renewable Generation						8		
Total Storage						0		
Total Generation						101		
Excess Generation						0		
Total Up Regulation						4		
Total Down Regulation						51		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-147. Unit Commitment and Dispatch

Table O-147 shows the unit commitment and dispatch schedule for the boundary hour (6/22/19, 3:00 AM).

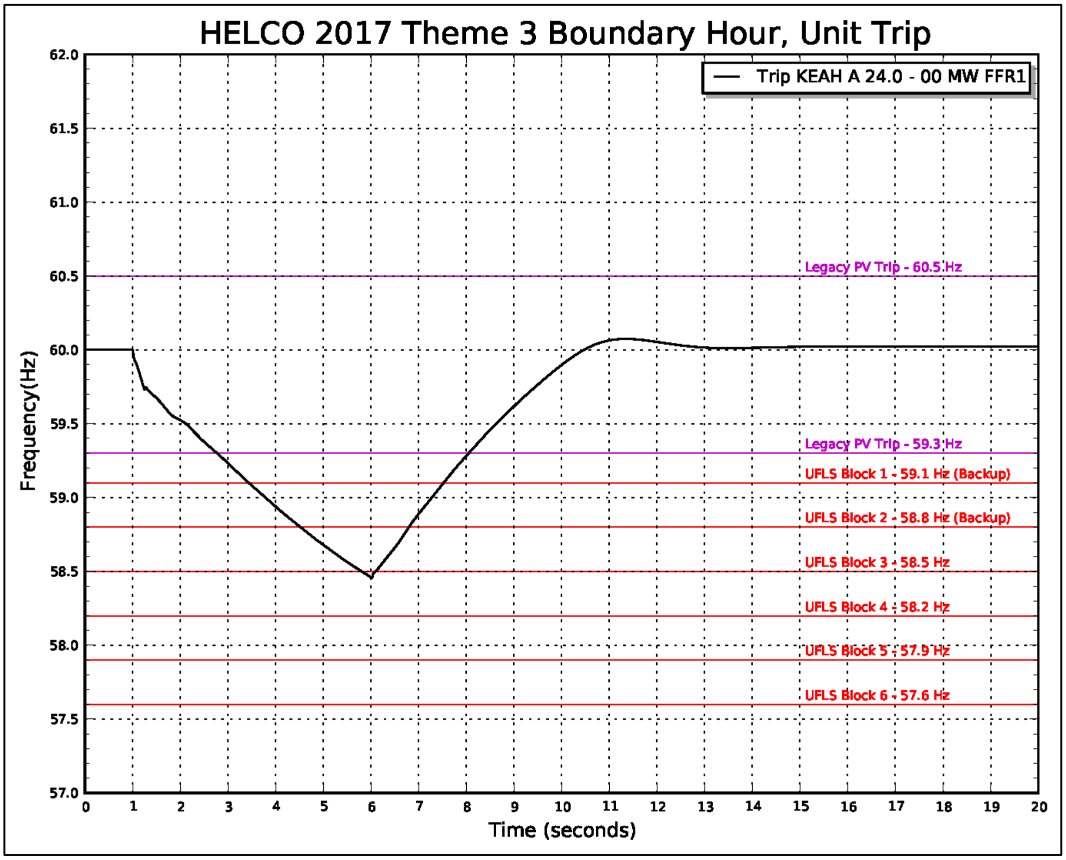

Figure O-340. Frequency Response Profile Boundary Hour

Figure O-340 shows the frequency response profile for a Keahole STCC trip at 24 MW for a boundary hour. The frequency nadir breached 58.5 Hz that requires three blocks of UFLS to stabilize system frequency. The system is not in compliance with TPL-001.

69 kV Fault Simulation

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 7 cycles depending on location of the fault relative to the breakers. Delayed clearing faults are modeled as a three- phase fault on the secondary bus of a tapped distribution transformer.

Unit	Unit Ratings					Theme 3 - Fault Sun 6/18/17 Hour 11		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	29.7	8.3	7.7
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53	9.0	11.0	2.0
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	8.0	5.5	3.0
Hill 6	20.5	8.0	2.53	27.5	70	11.3	9.2	3.3
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.0		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				14.5		
HRD	10.5	0.0				10.5		
Hydro	16.8	0				3		
Wind	31.0	0				25		
DG-PV	122.5	0				57		
Total Kinetic Energy							337	
Total Load							143	
Total Thermal Generation							58	
Total Renewable Generation							85	
Total Storage							0	
Total Generation							143	
Excess Generation							0	
Total Up Regulation							34	
Total Down Regulation							16	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.3
	60.5Hz Capacity			56.6		60.5Hz Output		30.6

Table O-148. Unit Commitment and Dispatch Fault Analysis

Table O-148 shows the unit commitment and dispatch for the 69 kV fault analysis (6/18/17, 11:00 AM). The capacity of DG-PV is 57 MW.

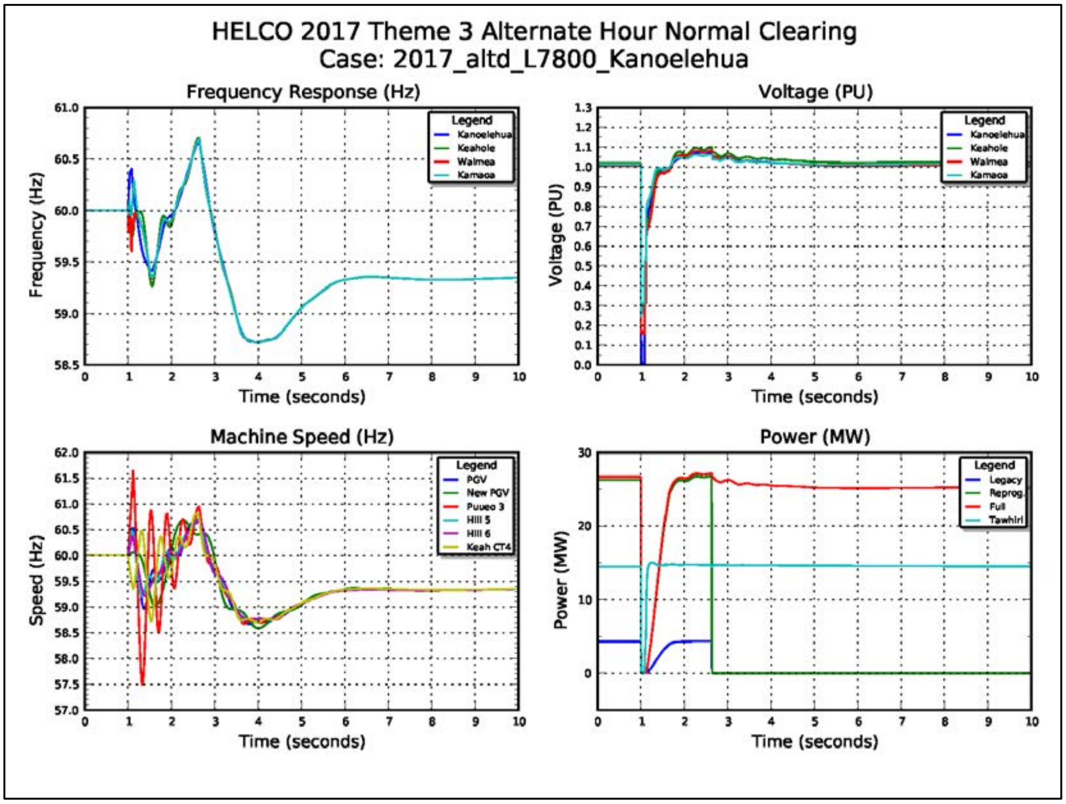

Figure O-341. System Performance for Normally Cleared Fault

Figure O-341 shows the system performance for a normally cleared fault at the Kanoelehua end of the L6400 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 57 MW from the system. System frequency initially increases but droop response from thermal units limit the initial apex to 60.4 Hz and frequency begins to decay. System voltage is restored when the fault is cleared, restoring generation from DG-PV. The aggregate frequency response from synchronous units, DG-PV restoration, and two blocks of df/dt UFLS is able to stabilize system frequency at 59.3 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping 37 MW of legacy PV. This drives system frequency to 58.8 Hz. System frequency eventually stabilizes but the margin of stability is tenuous.

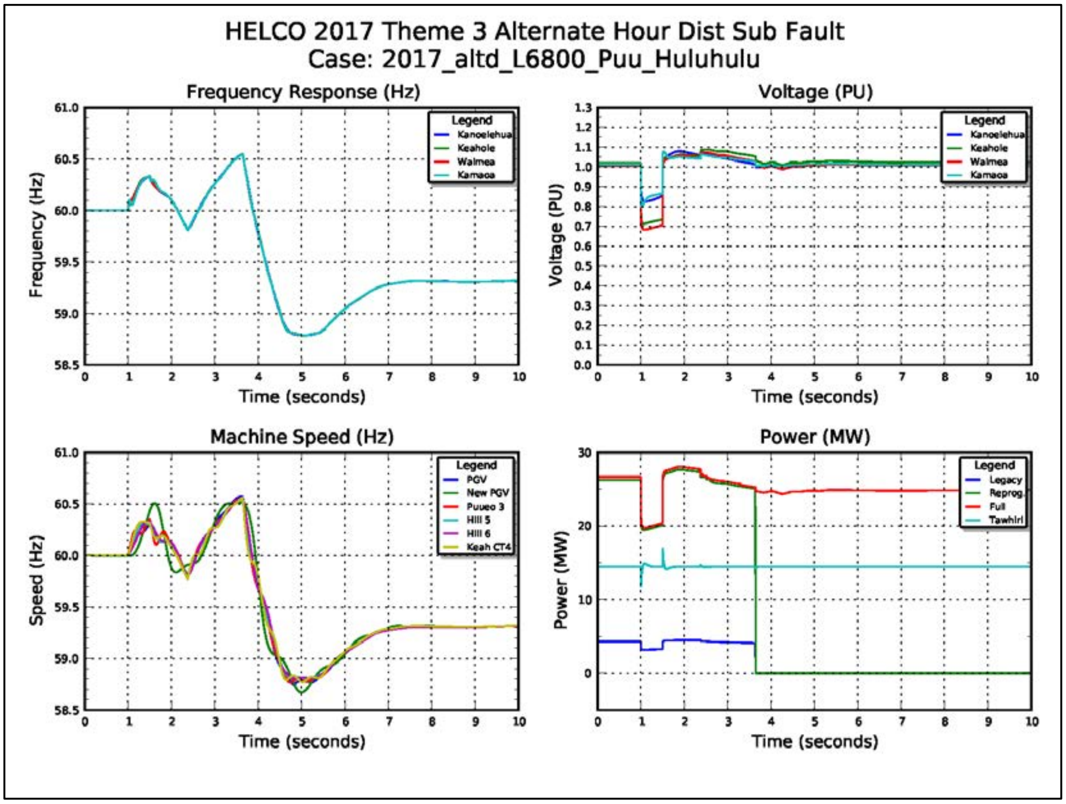

Figure O-342. System Performance for Delay Cleared Fault

Figure O-342 shows the system performance for a normally cleared fault at secondary side of the Pu'u Huluhulu distribution transformer. System voltage is suppressed but remains above the 0.5 PU voltage ride-through threshold for inverter-based generation. There is an immediate drop in DG-PV generation because of the drop in voltage until the fault is cleared. Downward limits the initial frequency apex at 60.3 Hz but once system voltage is restored, DG-PV generation is restored to pre-fault conditions. This drives system frequency above 60.5 Hz that trips 37.4 MW of legacy PV. Frequency response from synchronous generators and two blocks of UFLS are required to stabilize system frequency at 58.7 Hz.

Post April No DR Plan - Theme 3

System security analysis performed on the Theme 3 resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021.

2019

System security analysis was performed on the Theme 3 resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Hawai'i transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirement of 80 MVA on the 69 kV transmission system of which 25 MVA must be connected on the West side of the island. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai'i, the critical busses with the highest MVAR demand are the Anaeho'omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3- QV Dispatch Fri 4/19/19 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	34.2	3.8	12.2
Keahole STCC	25.0	7.0	3.13	46.5	146	22.0	3.0	15.0
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	33.2	26.8	14.7
Hill 5	13.5	5.0	2.20	15.6	34	12.4	1.1	7.4
Hill 6	20.5	8.0	2.53	27.5	70	19.7	0.8	11.7
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	4.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	4.5		
Apollo	20.5	0.0				20.2		
HRD	10.5	0.0				10.5		
Hydro	16.8	0				9		
Wind	31.0	0				31		
DG-PV	122.5	0						
Total Kinetic Energy						628		
Total Load						161		
Total Thermal Generation						122		
Total Renewable Generation						39		
Total Storage						0		
Total Generation						161		
Excess Generation						0		
Total Up Regulation						35		
Total Down Regulation						61		
Legacy DG-PV	59.3Hz Capacity		7.9			59.3Hz Output		0.0
	60.5Hz Capacity		56.6			60.5Hz Output		0.0

Table O-149. Unit Commitment and Dispatch 2019 QV Analysis

Table O-149 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		No DR- HELCO 2019 MVAR Capability Fri 4/19/19 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	30.4	-19.6	2.6	27.8	-22.1
Keahole STCC	31.6	-23.1	30.3	1.3	-53.4
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	51.9	-30.5	1.2	50.7	-31.7
Hill 5	6.1	-5.5	2.8	3.3	-8.4
Hill 6	13.3	-11.4	5.0	8.3	-16.4
Puna	6.7	-6.2			
Keah CT2	15.0	-11.5			
Puna CT3	14.8	-10.6			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2	-6.7	11.9	-3.4
HRD	4.0	-4.0	-4.0	8.0	0.0
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			41.9		
Total Renewable MVAR Generation			-10.7		
Total Cap Bank MVAR			24.8		
Charging MVAR			16.1		
Total MVAR Supply			72.1		
Total MVAR Load			39.9		
Total MVAR Losses			32.2		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				111	
Total MVAR Absorb Capability					-135.5

Table O-150. MVAR Capability 2019 QV Analysis

Table O-150Table O-11. shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina
37	L7700 Waimea
45	L8300 Mauna Lani-Ouli
50	L8600 Kahaluu
55	L9100 Keahole-Poopoomino

Table O-151. N-1 Contingencies2019 QV Analysis

Table O-151shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

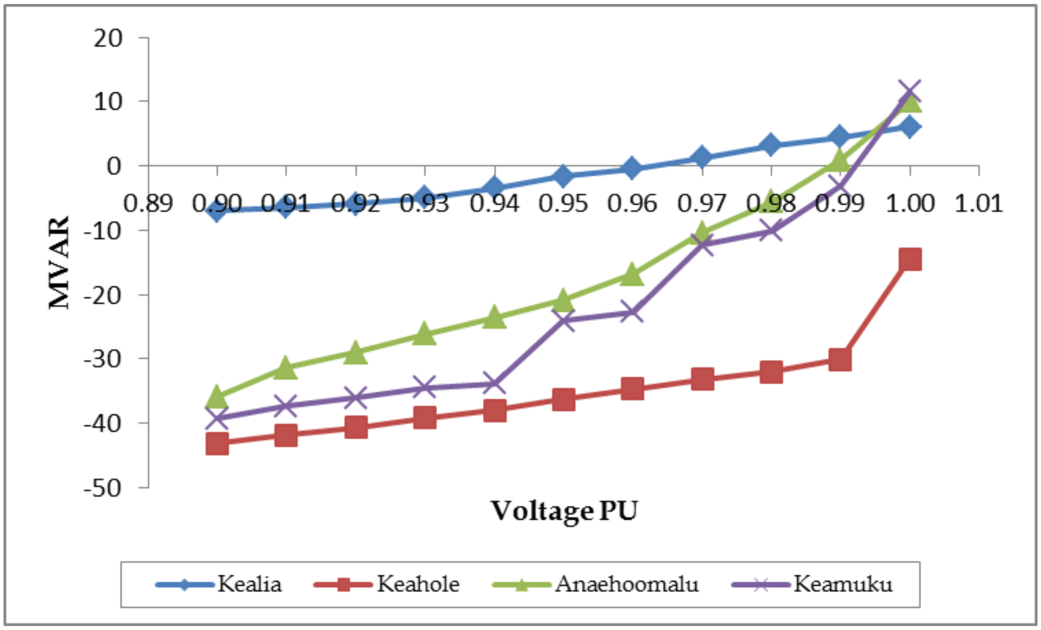

Figure O-343. QV Curves 2019

Figure O-343 shows the QV curves for the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The unit commitment and dispatch meets the reactive power requirements of the system under N-1 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	50	6	50	4	50	3	50	1	50	0	50	-2	50	-3	50	-5	50	-6	50	-6	50	-7
8400	Keahole	37	-14	45	-30	36	-32	36	-33	36	-35	36	-36	36	-38	36	-39	36	-41	36	-42	36	-43
8500	Anaehoomalu	36	10	55	1	55	-6	45	-10	36	-17	55	-21	55	-24	55	-26	55	-29	55	-31	36	-36
8700	Keamuku	36	12	36	-3	36	-10	36	-12	36	-23	36	-24	36	-34	36	-35	36	-36	36	-37	36	-39

Table O-152. Results 2019 QV Analysis

Table O-152 shows the summary of results for the 2019 QV analysis. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

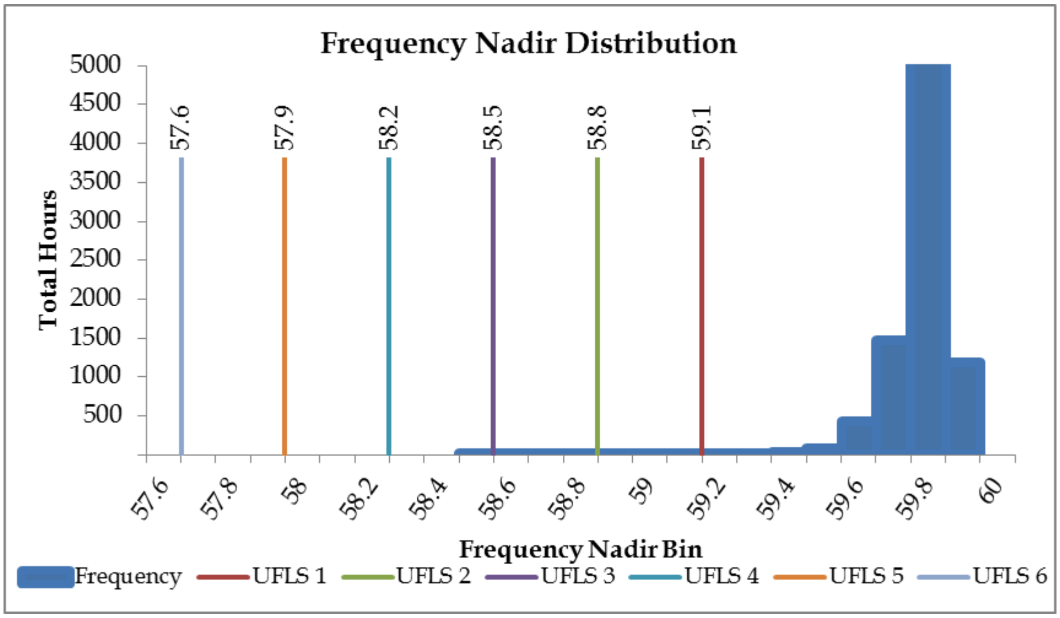

Figure O-344. Frequency Nadir Histogram for 2019

Figure O-344 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A boundary hour was selected from the maximum distribution of 11 hours was 3:00 AM on Saturday, June 22. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

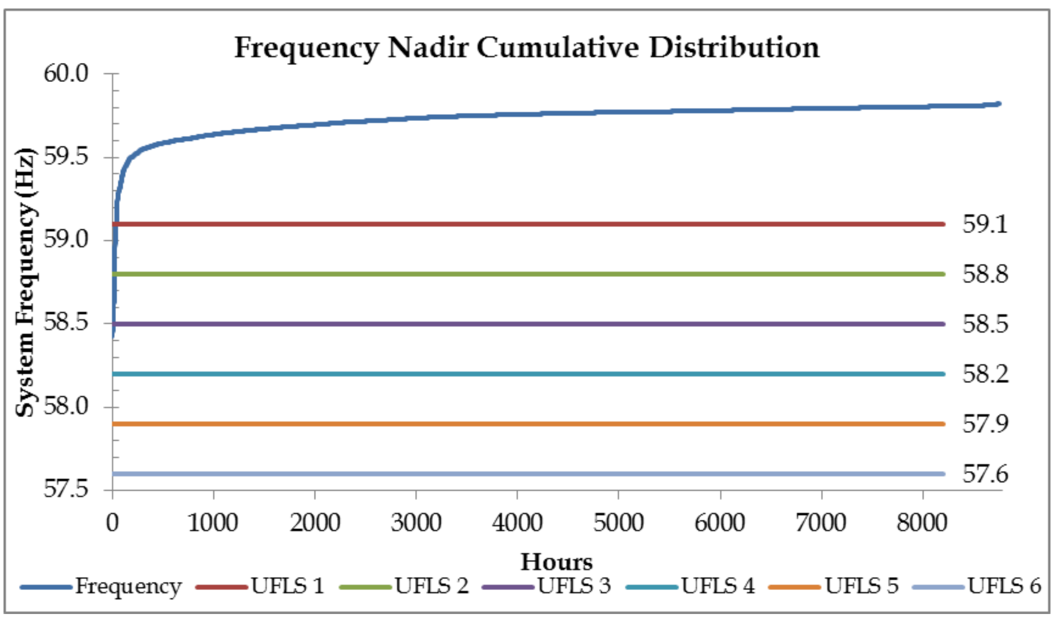

Figure O-345. Frequency Nadir Duration Curve 2019

Figure O-345 shows the frequency nadir duration curve for the Theme 3 resource plan in 2019. The system is at risk of exceeding the UFLS requirements of TPL-001 for 11 hours of the year.

Unit	Unit Ratings					Theme 3 - Keahole STCC Trip Boundary Sat 6/22/19 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	35.3	2.7	13.3
Keahole STCC	25.0	7.0	3.13	46.5	146	23.9	1.1	16.9
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	11.9	1.6	6.9
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	5.2		
Apollo	20.5	0.0				11.5		
HRD	10.5	0.0				3.6		
Hydro	16.8	0				9		
Wind	31.0	0				15		
DG-PV	122.5	0						
Total Kinetic Energy						390		
Total Load						95		
Total Thermal Generation						71		
Total Renewable Generation						24		
Total Storage						0		
Total Generation						95		
Excess Generation						0		
Total Up Regulation						5		
Total Down Regulation						37		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-153. Unit Commitment and Dispatch 2019

Table O-153 shows the unit commitment and dispatch for the typical hour (6/22/2019, 3:00 AM).

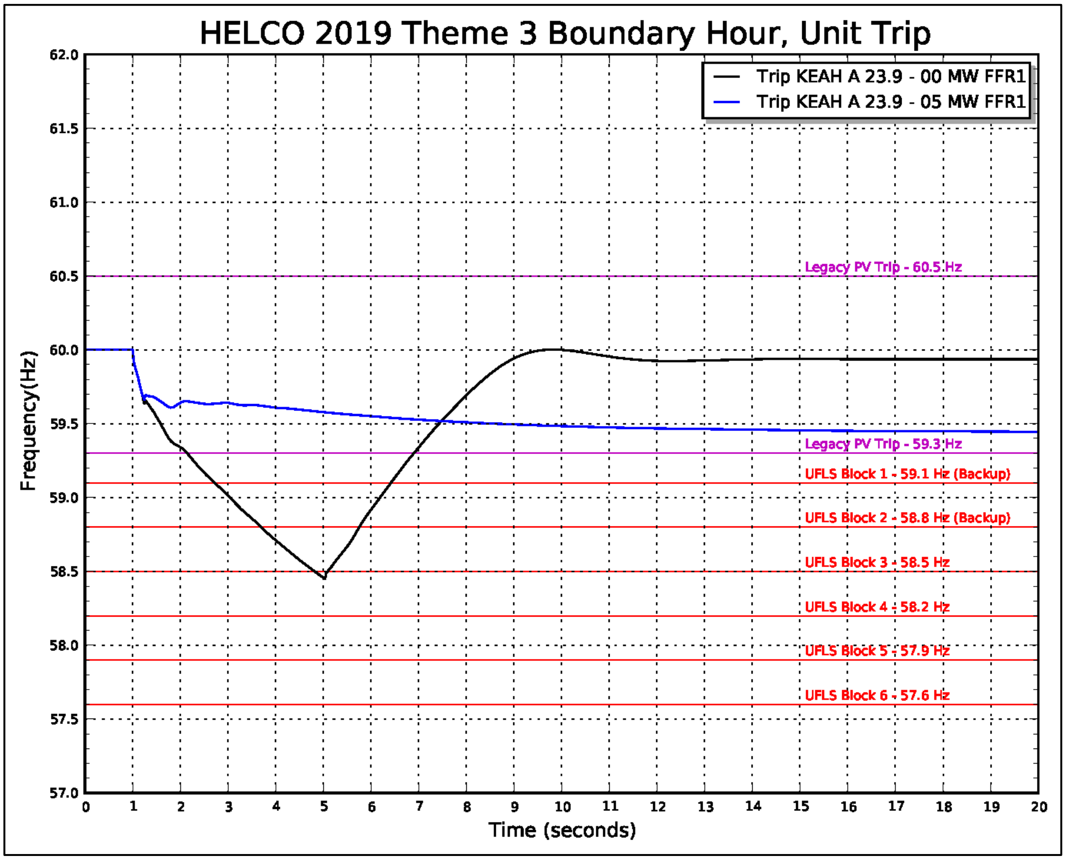

Figure O-346. Frequency Response Profile for FFR1 Boundary Hour

Figure O-346 shows the frequency response profile for a Keahole STCC trip at 24 MW. System kinetic energy is 390 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 3 MW.

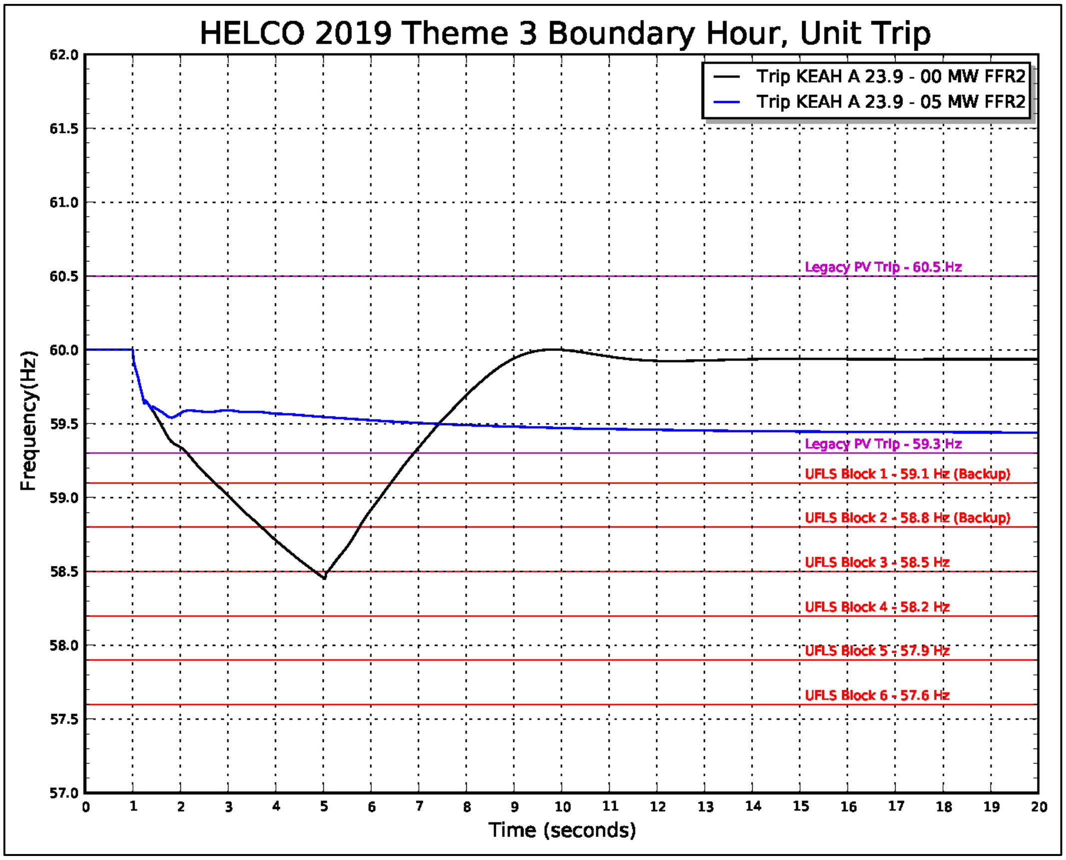

Figure O-347. Frequency Response Profile for FFR2 Typical Hour

Figure O-347 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 3 MW.

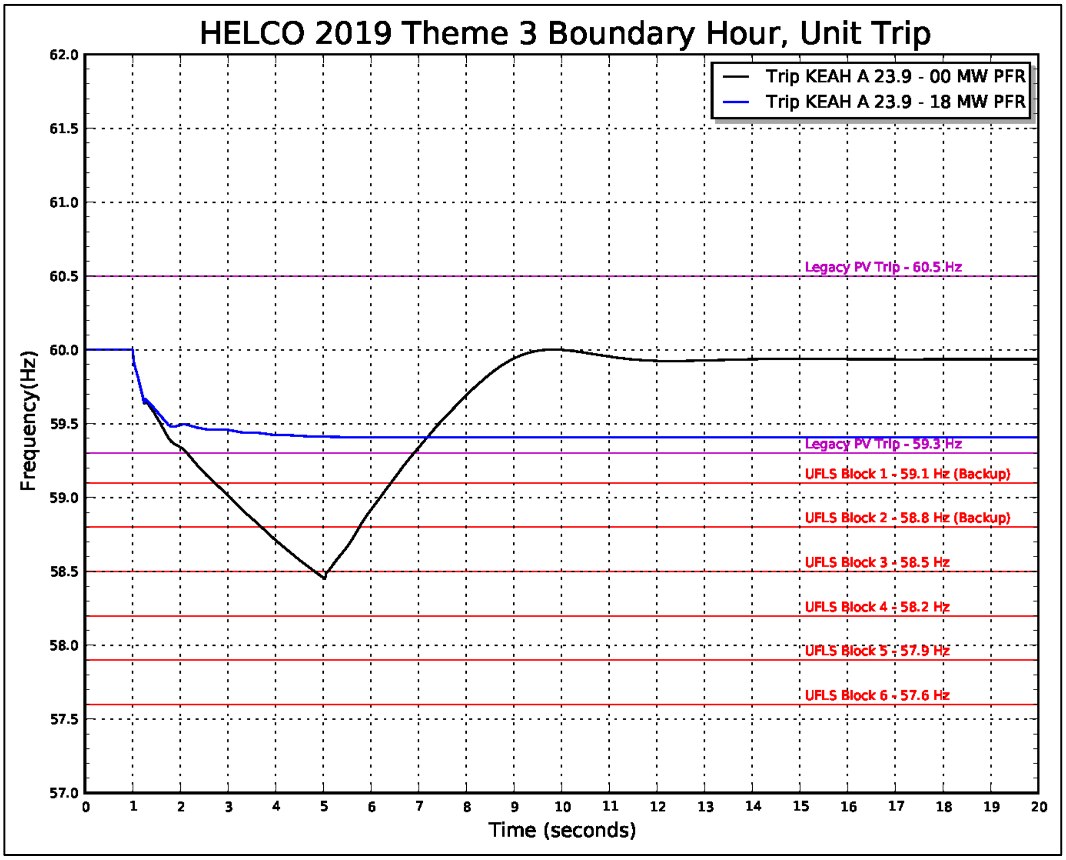

Figure O-348. Frequency Response Profile for PFR Typical Hour

Figure O-348 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 4 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

A three-phase fault was placed on a transmission line to evaluate system performance for normally cleared faults. Normally cleared faults are isolated in 5 to 7 cycles depending on location of the fault relative to the breakers. Delayed clearing faults are modeled as a three-phase fault on the secondary bus of a tapped distribution transformer.

Unit	Unit Ratings					Theme 3 - Fault Sun 2/10/19 Hour 12		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146	11.8	13.2	4.8
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	10.0	3.5	5.0
Hill 6	20.5	8.0	2.53	27.5	70	17.2	3.3	9.2
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	2.1		
Apollo	20.5	0.0				20.3		
HRD	10.5	0.0				4.7		
Hydro	16.8	0				4		
Wind	31.0	0				25		
DG-PV	122.5	0				81		
Total Kinetic Energy							286	
Total Load							149	
Total Thermal Generation							39	
Total Renewable Generation							110	
Total Storage							0	
Total Generation							149	
Excess Generation							0	
Total Up Regulation							20	
Total Down Regulation							19	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		5.2
	60.5Hz Capacity			56.6		60.5Hz Output		37.4

Table O-154. Unit Commitment and Dispatch Fault Analysis

Table O-154 shows the unit commitment and dispatch for the 69 kV fault analysis (2/10/19, 12:00 PM).

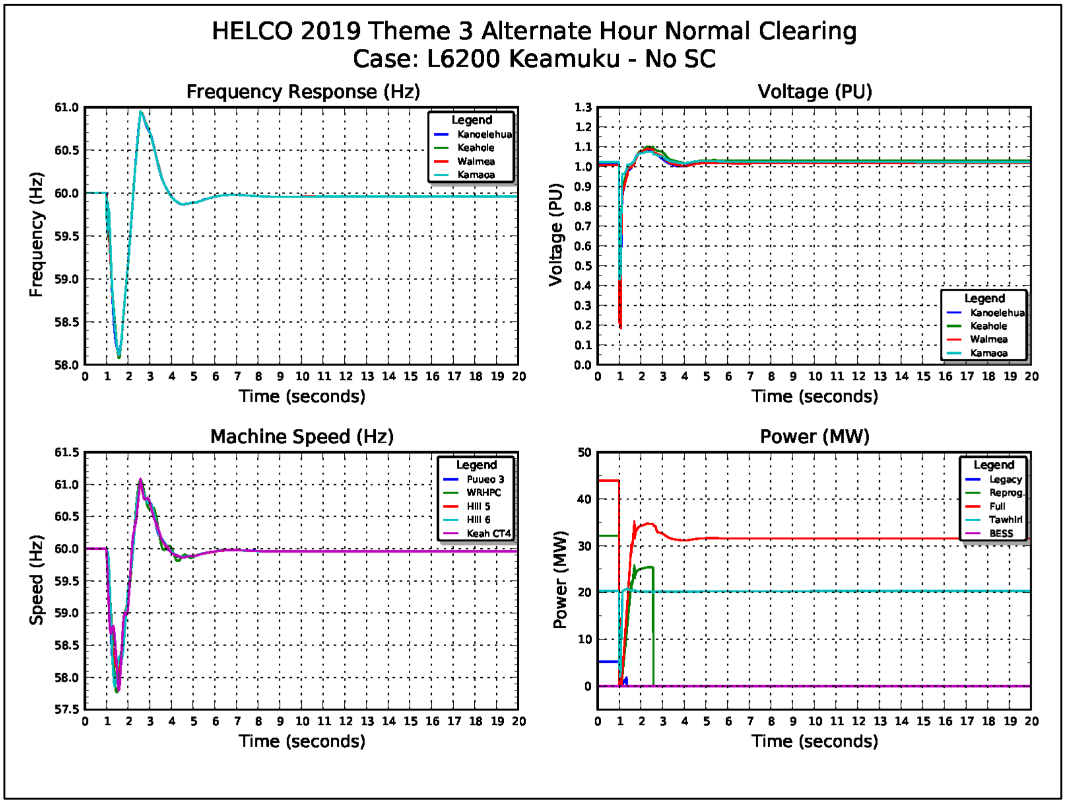

Figure O-349. System Performance Normally Cleared Fault

Figure O-349 shows the system performance for a normally cleared fault at the Keamuku end of the L6200 circuit. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 81 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from some DG-PV is restored when system voltage recovers but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and five blocks of UFLS is able to stabilize system frequency at 58.1 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet TPL-001 and/or improve the stability margin of the system. The analysis was performed for the L6200 circuit only.

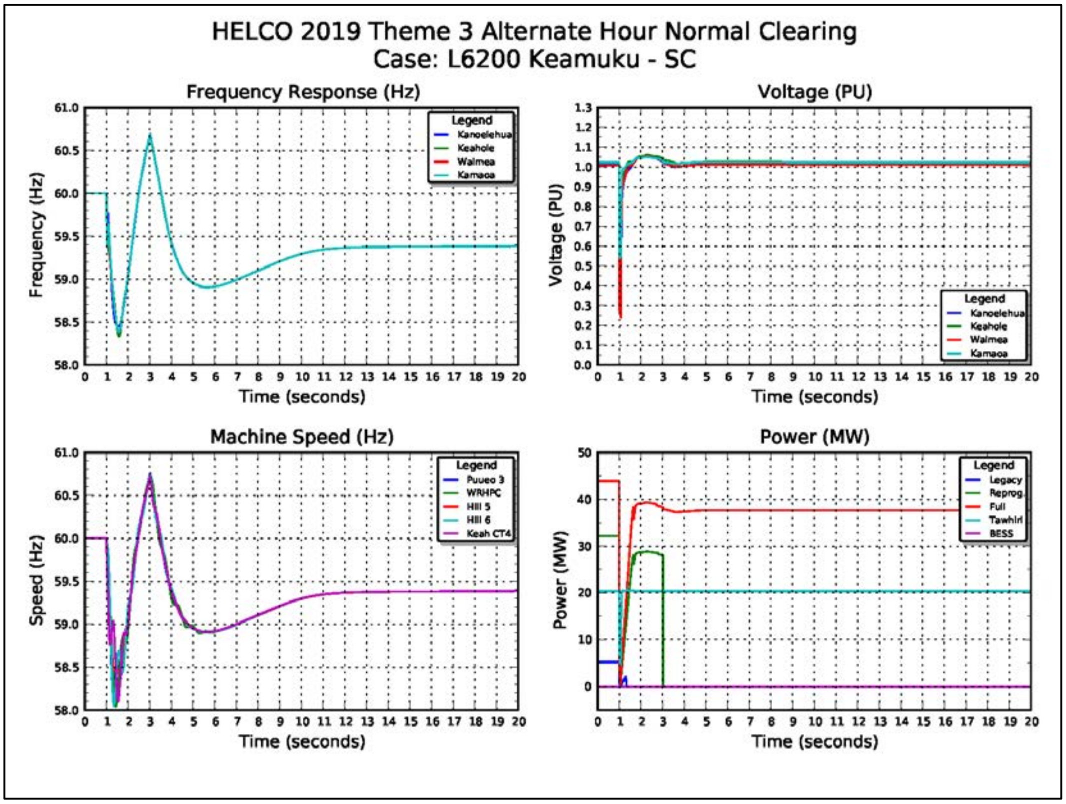

Figure O-350. Normally Cleared Fault Sensitivity Synchronous Condenser

Figure O-350 shows system performance with the addition of two synchronous condensers totaling 34 MVA located at Keahole. The synchronous condensers add inertia, short circuit current, voltage support/ MVAR capability, and increases the magnetic strength of the system. Frequency response improves with the synchronous condenser as the frequency nadir is elevated to 58.4 Hz, reducing UFLS to three blocks but the system is not in compliance with TPL-001.

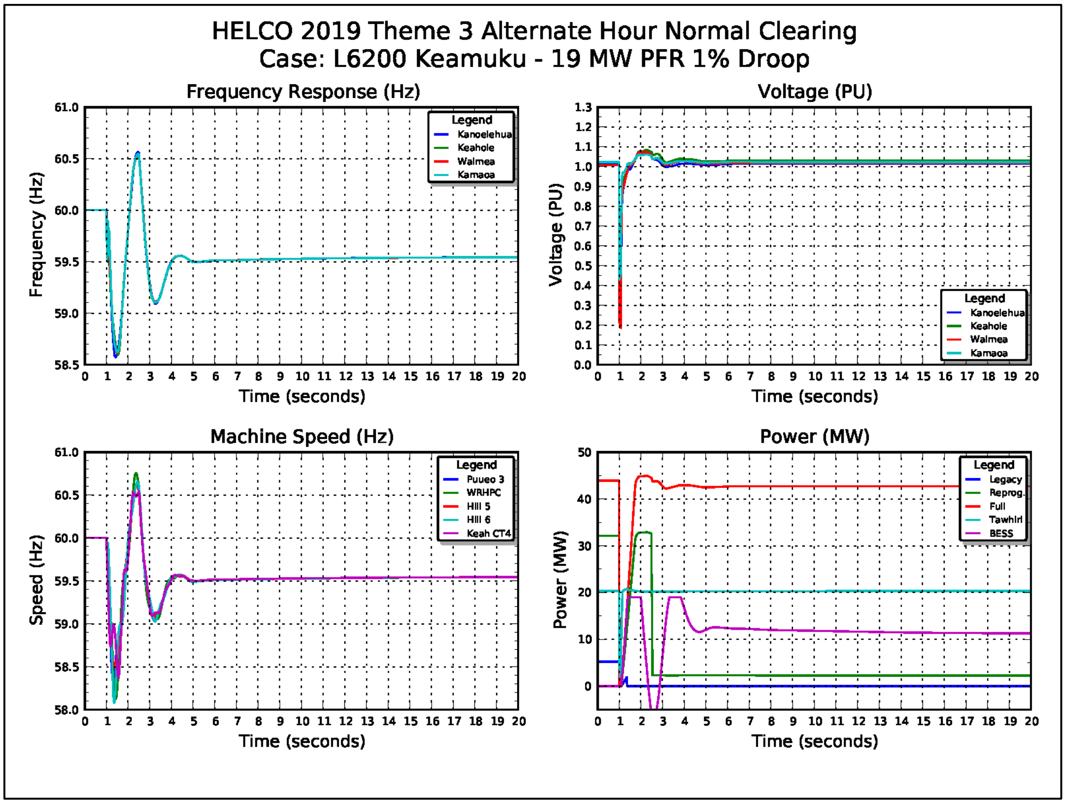

Figure O-351. Normally Cleared Fault Sensitivity 19 MW PFR

Figure O-351 shows system performance with the addition of 19 MW PFR at 1% droop response. For the purpose of this analysis, a 19 MW BESS was located at the Anaeho'omalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, Tawhiri wind plant, and the 19 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai'i, the critical busses with the highest MVAR demand are the Anaeho'omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 - QV Dispatch Sat 2/29/20 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146	19.6	5.4	12.6
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	49.7	10.3	31.2
Hill 5	13.5	5.0	2.20	15.6	34	12.1	1.4	7.1
Hill 6	20.5	8.0	2.53	27.5	70	18.0	2.5	10.0
Puna	15.5	6.0	4.63	18.8	87	6.2	9.3	0.2
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	19.0	1.0	12.0
Synch. Cond. 1	0.0	0.0	2.00	15.6	31			
Synch. Cond. 2	0.0	0.0	2.00	18.8	38			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	7.6		
Apollo	20.5	0.0						
HRD	10.5	0.0				0.7		
Hydro	16.8	0				9		
Wind	31.0	0				1		
DG-PV	128.8	0						
Total Kinetic Energy						861		
Total Load						171		
Total Thermal Generation						161		
Total Renewable Generation						10		
Total Storage						0		
Total Generation						171		
Excess Generation						0		
Total Up Regulation						31		
Total Down Regulation						88		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-155. Unit Commitment and Dispatch 2020 QV Analysis

Table O-155shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Sat 2/29/20 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	30.4	-19.6	1.2	29.2	-20.8
Keahole STCC	31.6	-23.1	31.6	0.0	-54.7
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	51.9	-30.5	-0.1	52.0	-30.4
Hill 5	6.1	-5.5	2.2	3.9	-7.7
Hill 6	13.3	-11.4	3.8	9.5	-15.2
Puna	14.3	-8.9	-0.7	15.1	-8.2
Keah CT2	15.0	-11.5			
Puna CT3	15.6	-11.0	-1.2	16.8	-9.8
Synch. Cond. 1	11.6	-9.4			
Synch. Cond. 2	14.3	-8.9			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2			
HRD	4.0	-4.0	0.4	3.6	-4.4
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			36.8		
Total Renewable MVAR Generation			0.4		
Total Cap Bank MVAR			24.6		
Charging MVAR			16.0		
Total MVAR Supply			77.9		
Total MVAR Load			43.1		
Total MVAR Losses			34.8		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				130	
Total MVAR Absorb Capability					-151.3

Table O-156. MVAR Capability 2020 QV Analysis

Table O-156 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina
37	L7700 Waimea
48	L8600 Kealia-Kahaluu
49	L8600 Kealia

Table O-157. N-1 Contingencies2020 QV Analysis

Table O-157 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

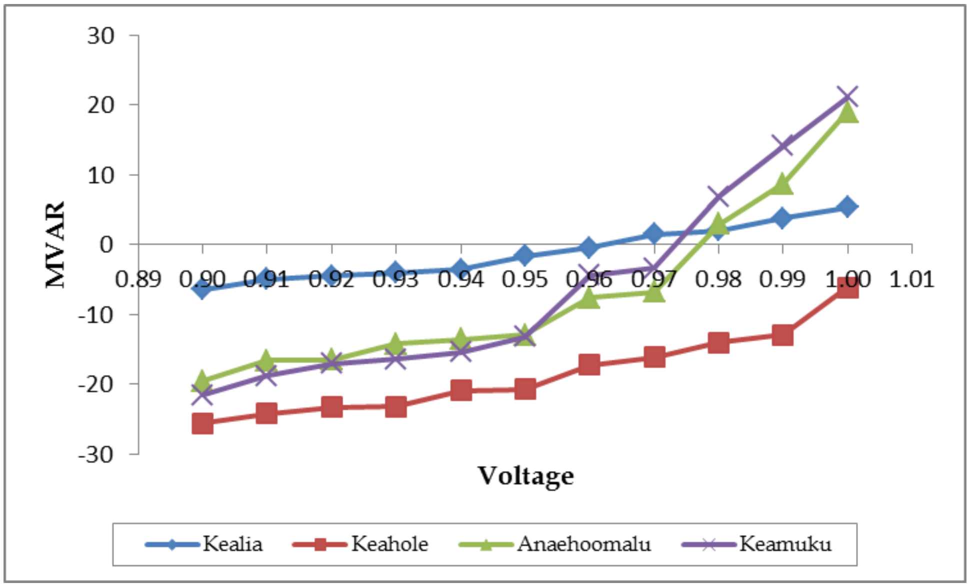

Figure O-352. QV Curves 2020

Figure O-352 shows the QV curves for the Anaeho'omalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The unit commitment and dispatch meets the reactive power requirements of the system under N-1 contingencies.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	5	36	4	49	2	49	1	49	0	48	-2	49	-4	48	-4	49	-5	48	-5	48	-6
8400	Keahole	36	-6	36	-13	36	-14	36	-16	36	-17	36	-21	36	-21	36	-23	36	-23	36	-24	36	-26
8500	Anaehoomalu	36	19	36	9	36	3	36	-7	36	-8	36	-13	36	-14	36	-14	36	-17	36	-17	36	-20
8700	Keamuku	37	21	37	14	36	7	36	-3	36	-4	37	-13	36	-15	36	-16	36	-17	36	-19	36	-22

Table O-158. Results 2020 QV Analysis

Table O-158 shows the summary of results for the 2020 QV analysis. No additional resources are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

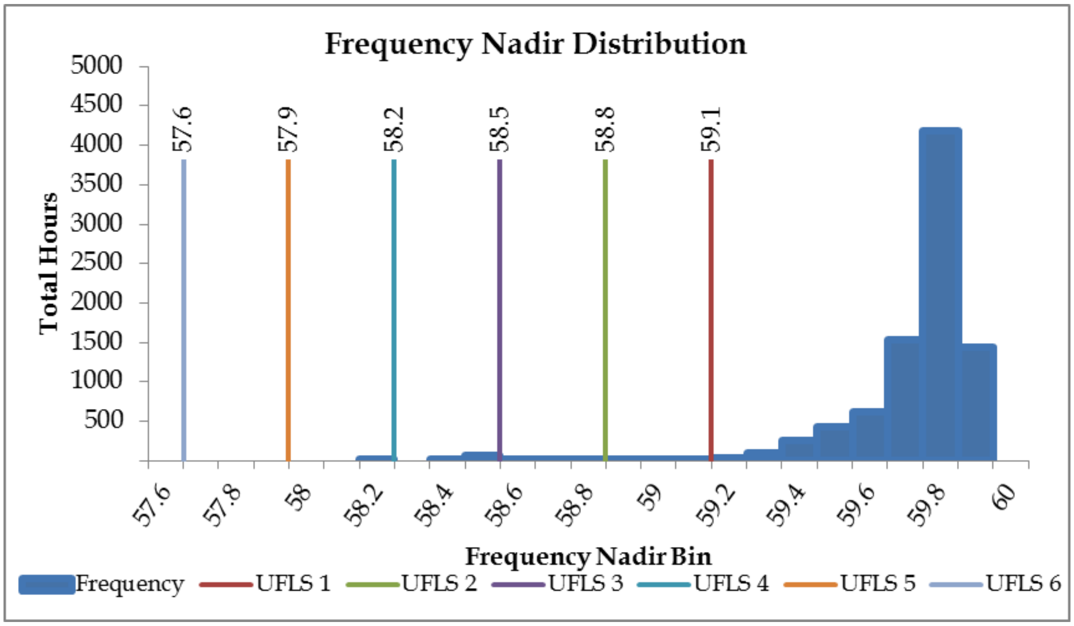

Figure O-353. Frequency Nadir Histogram for 2020

Figure O-353 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. The typical hour was selected from the hourly distribution of 72 hours was 3:00 PM on Friday, May 1. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from a distribution of one hour was 12:00 PM on Sunday, July 19. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires four blocks of UFLS to stabilize system frequency.

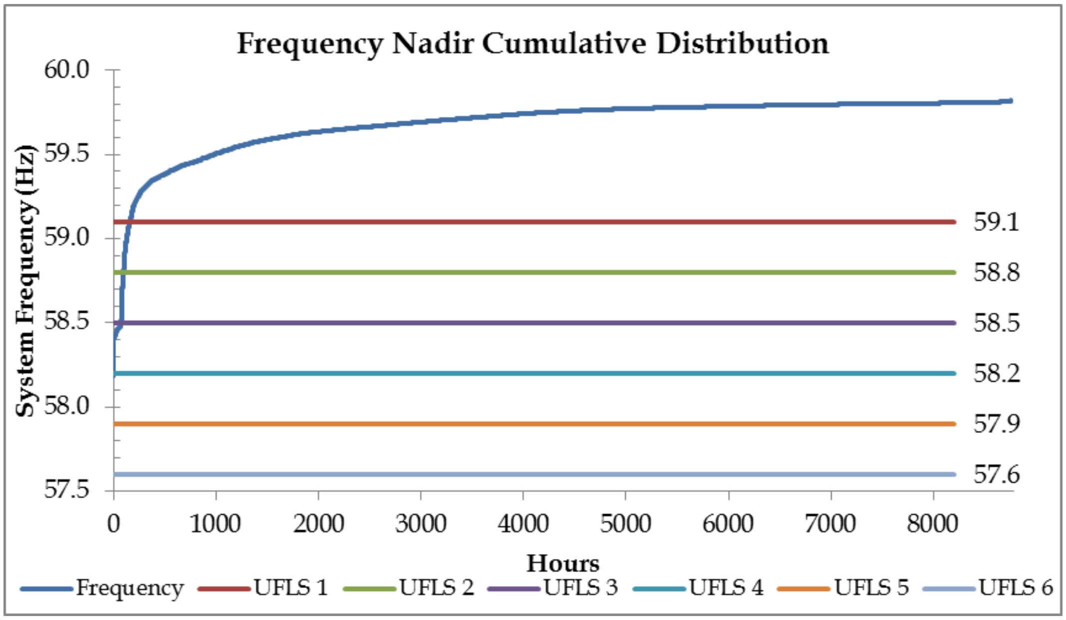

Figure O-354. Frequency Nadir Duration Curve 2020

Figure O-354 shows the frequency nadir duration curve for the Theme 3 resource plan in 2020. The system is at risk of exceeding the UFLS requirements of TPL-001 for 74 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Typical Wed 2/26/20 Hour 15			Theme 3 - HEP STCC Trip Boundary Wed 1/29/20 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146						
Keahole DTCC	54.0	7.0	2.77	71.8	199						
Keahole CT4	20.0	7.0	2.10	25.2	53						
Keahole CT5	20.0	7.0	2.10	25.2	53						
HEP STCC	28.5	9.0	1.96	58.9	116	22.0	6.5	13.0	24.0	4.5	15.0
HEP DTCC	60.0	18.5	1.78	94.4	168						
Hill 5	13.5	5.0	2.20	15.6	34						
Hill 6	20.5	8.0	2.53	27.5	70						
Puna	15.5	6.0	4.63	18.8	87						
Keah CT2	13.8	5.0	4.44	22.2	99						
Puna CT3	20.0	7.0	4.96	29.6	147						
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.		0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.		0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9			2.5		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	12.0			1.6		
Apollo	20.5	0.0				7.9			9.8		
HRD	10.5	0.0									
Wind1	20.0	0.0				6.0			6.0		
Hydro	16.8	0				14			4		
Wind	31.0	0				14			16		
DG-PV	128.8	0				75					
Total Kinetic Energy							394			394	
Total Load							161			82	
Total Thermal Generation							58			62	
Total Renewable Generation							102			20	
Total Storage							0			0	
Total Generation							161			82	
Excess Generation							0			0	
Total Up Regulation							8			4	
Total Down Regulation							27			31	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.6	59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		32.8	60.5Hz Output		0.0

Table O-159. Unit Commitment and Dispatch 2020

Table O-159 shows the unit commitment and dispatch for the typical hour (2/26/20, 3:00 PM) and boundary hour (1/29/20, 3:00 AM).

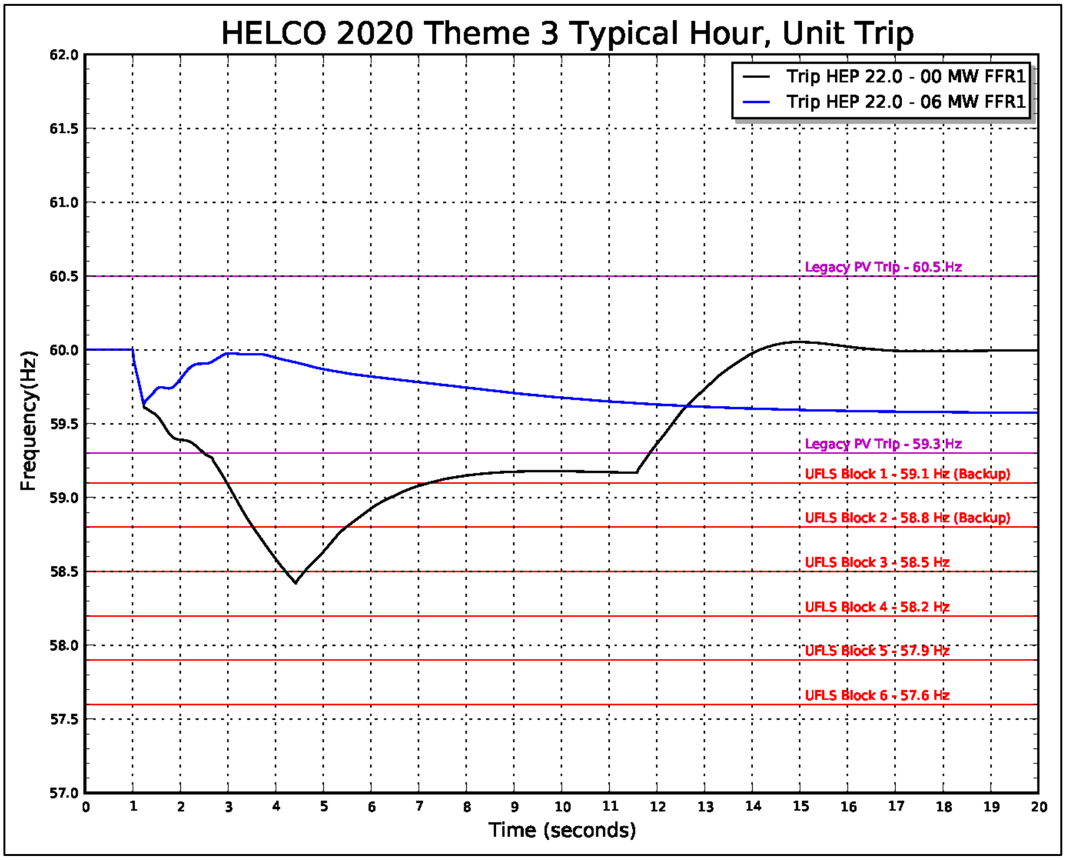

Figure O-355. Frequency Response Profile for FFR1 Typical Hour

Figure O-355 shows the frequency response profile for a HEP trip at 22 MW. System kinetic energy is 326 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5 MW. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 6 MW.

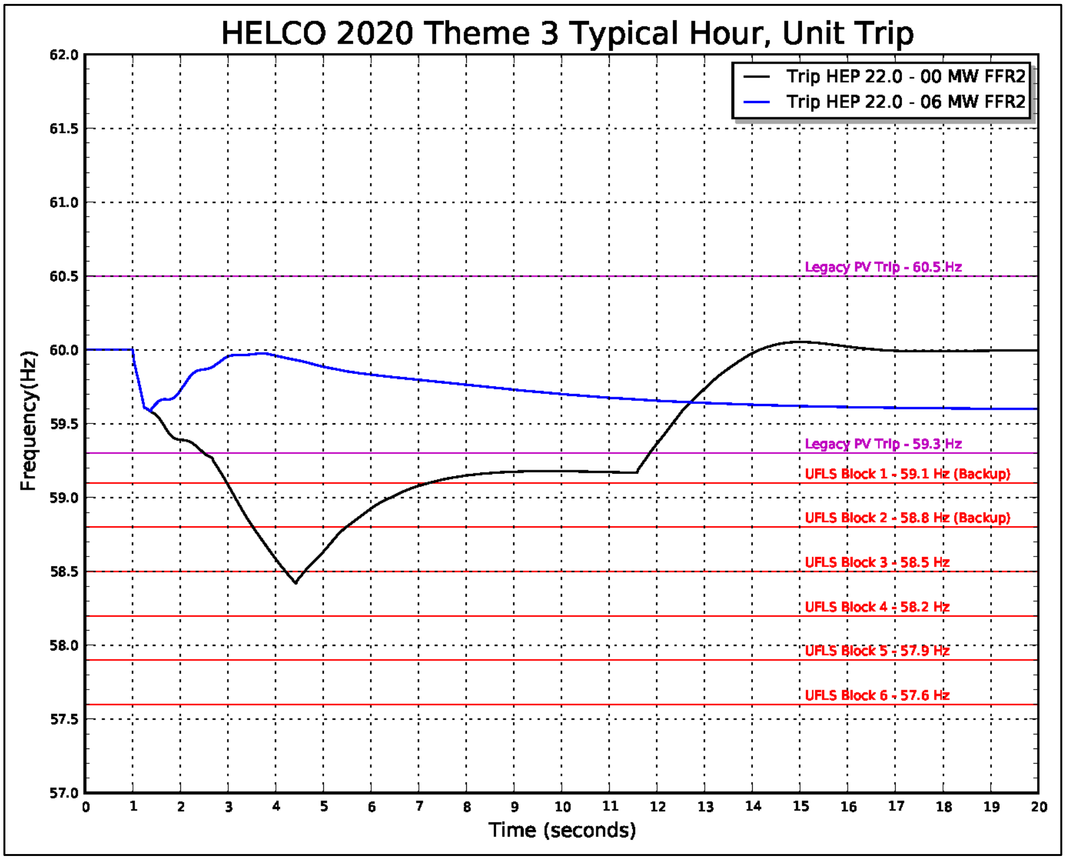

Figure O-356. Frequency Response Profile for FFR2 Typical Hour

Figure O-356 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 6 MW.

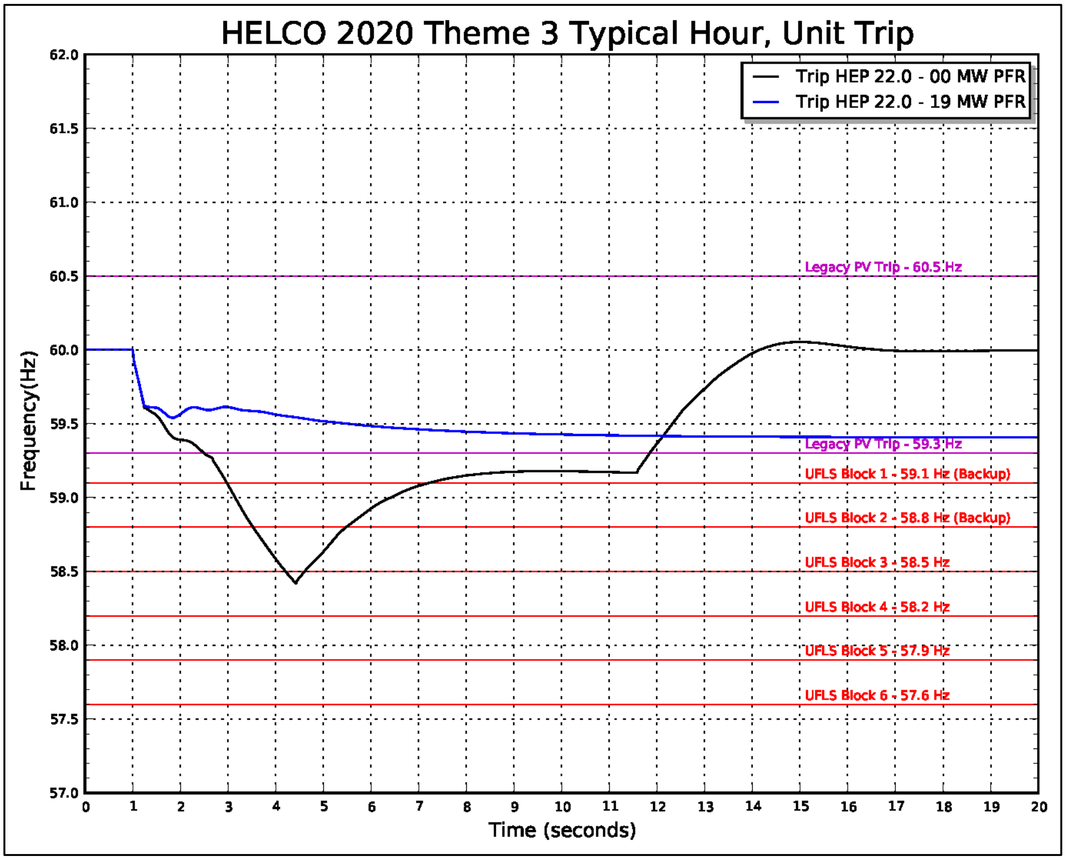

Figure O-357. Frequency Response Profile for PFR Typical Hour

Figure O-357 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 19 MW. This is in addition to the 8 MW of upward regulation from thermal generation.

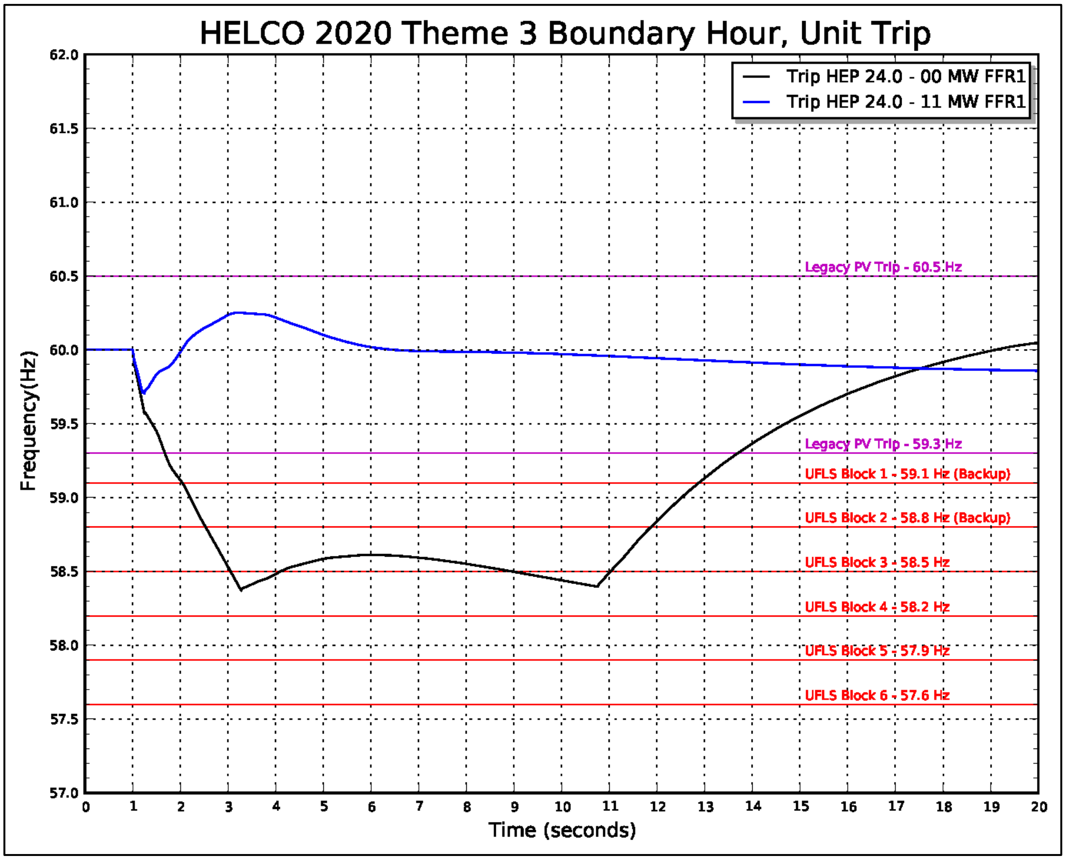

Figure O-358. Frequency Response Profile for FFR1 Boundary Hour

Figure O-358 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 326 MW-sec. With no FFR, the frequency nadir breaches 58.4 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 11 MW.

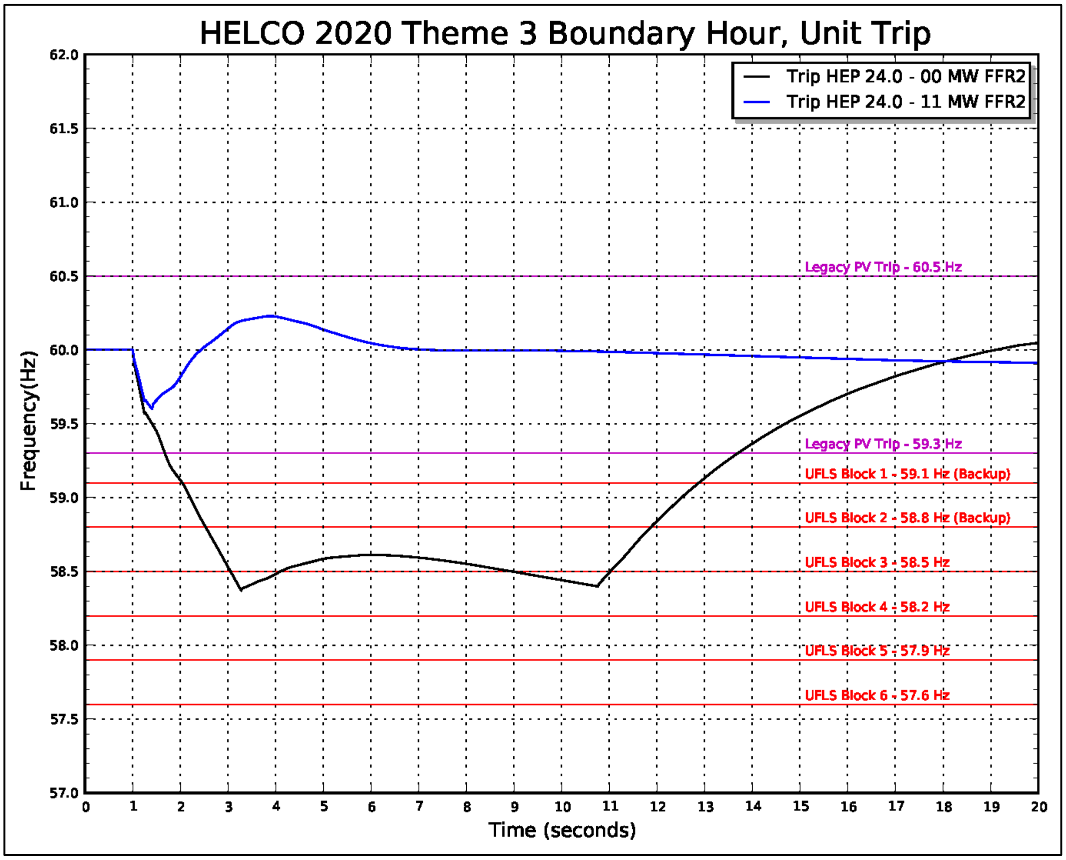

Figure O-359. Frequency Response Profile for FFR2 Typical Hour

Figure O-359 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 11 MW.

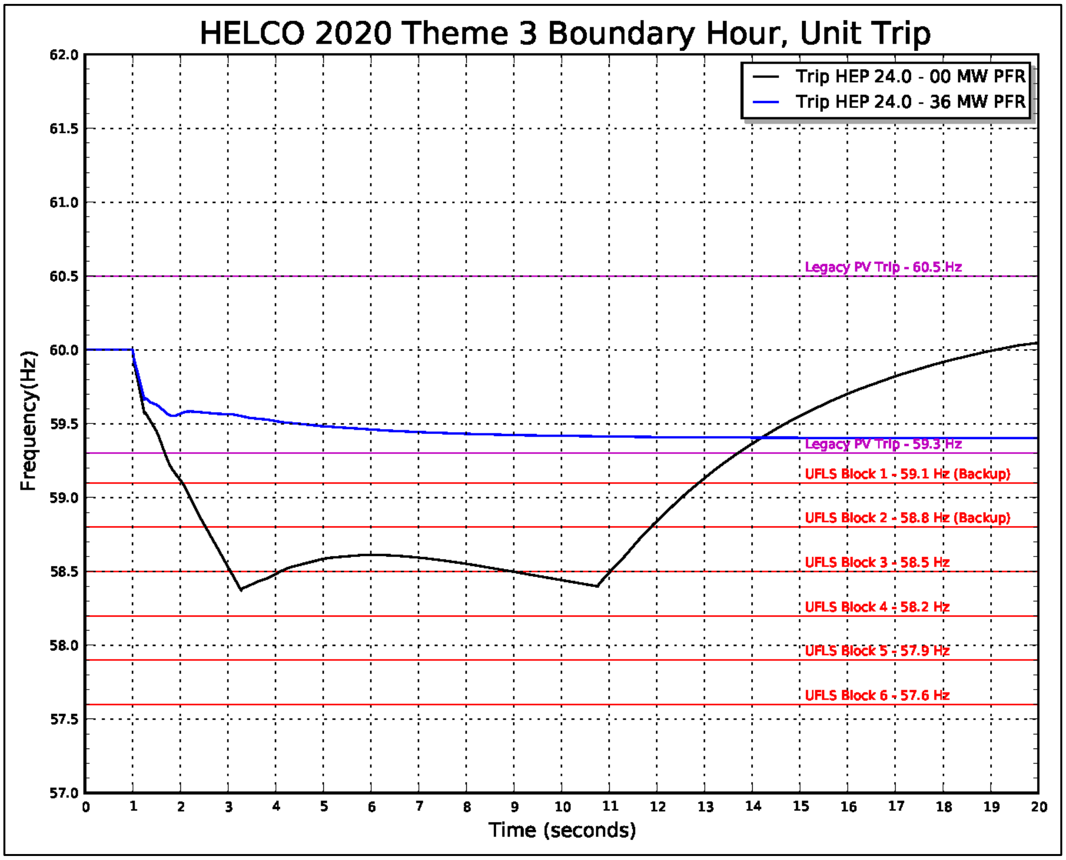

Figure O-360. Frequency Response Profile for PFR Typical Hour

Figure O-360 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 36 MW. This is in addition to the 4 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most sever disturbance on the transmission system typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					Theme 3 - Fault Sat 2/8/20 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	33.2	4.8	11.2
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	11.2	17.3	2.2
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				18.3		
HRD	10.5	0.0				2.5		
Wind1	20.0	0.0				3.0		
Hydro	16.8	0				2		
Wind	31.0	0				24		
DG-PV	128.8	0				86		
Total Kinetic Energy							365	
Total Load							156	
Total Thermal Generation							44	
Total Renewable Generation							112	
Total Storage							0	
Total Generation							156	
Excess Generation							0	
Total Up Regulation							22	
Total Down Regulation							13	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		5.3
	60.5Hz Capacity			56.6		60.5Hz Output		37.9

Table O-160. Unit Commitment and Dispatch Fault Analysis

Table O-160 shows the unit commitment and dispatch for the 69 kV fault analysis. The capacity of DG-PV is 86 MW.

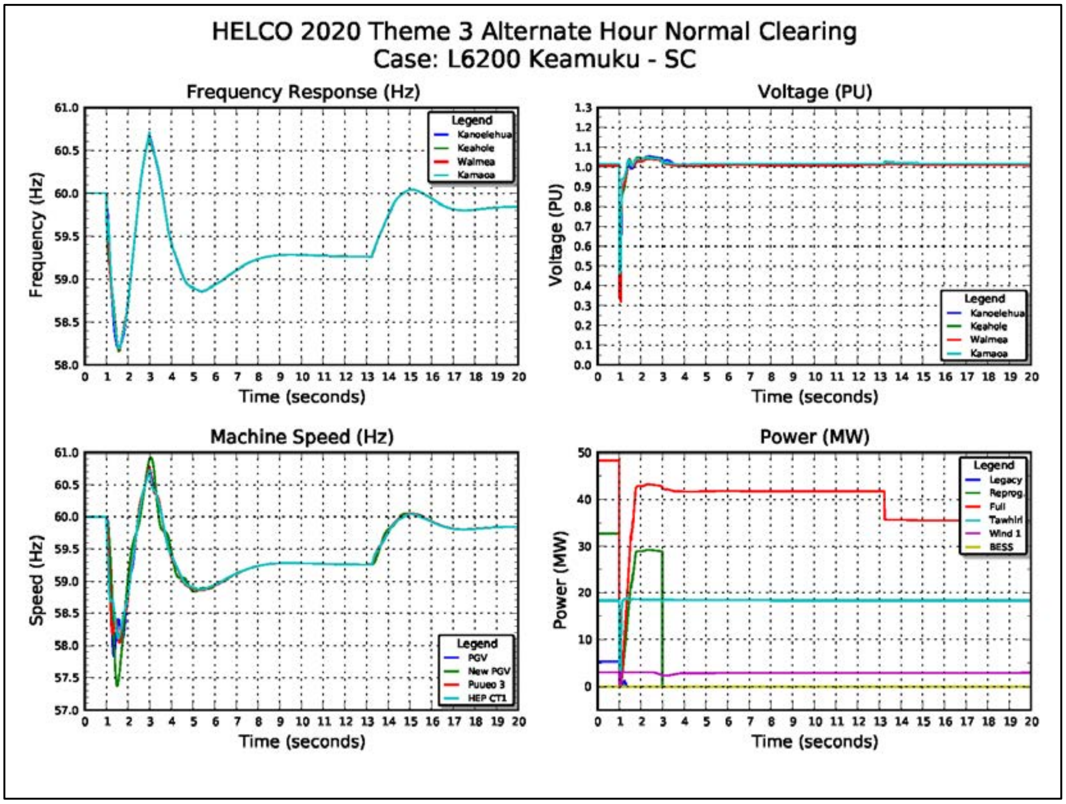

Figure O-361. System Performance Normally Cleared Fault

Figure O-361 shows the system performance for a normally cleared fault at the Keamuku end of the L6200 circuit. System voltage is suppressed below the 0.5 PU low voltage ride-through threshold for inverter-based PV generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 86 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from some DG-PV is restored when system voltage recovers but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and four blocks of UFLS is able to stabilize system frequency at 58.2 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

The system remains stable for normally cleared faults on any Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet the requirements of TPL-001. Analysis was performed on the L6200 circuit only.

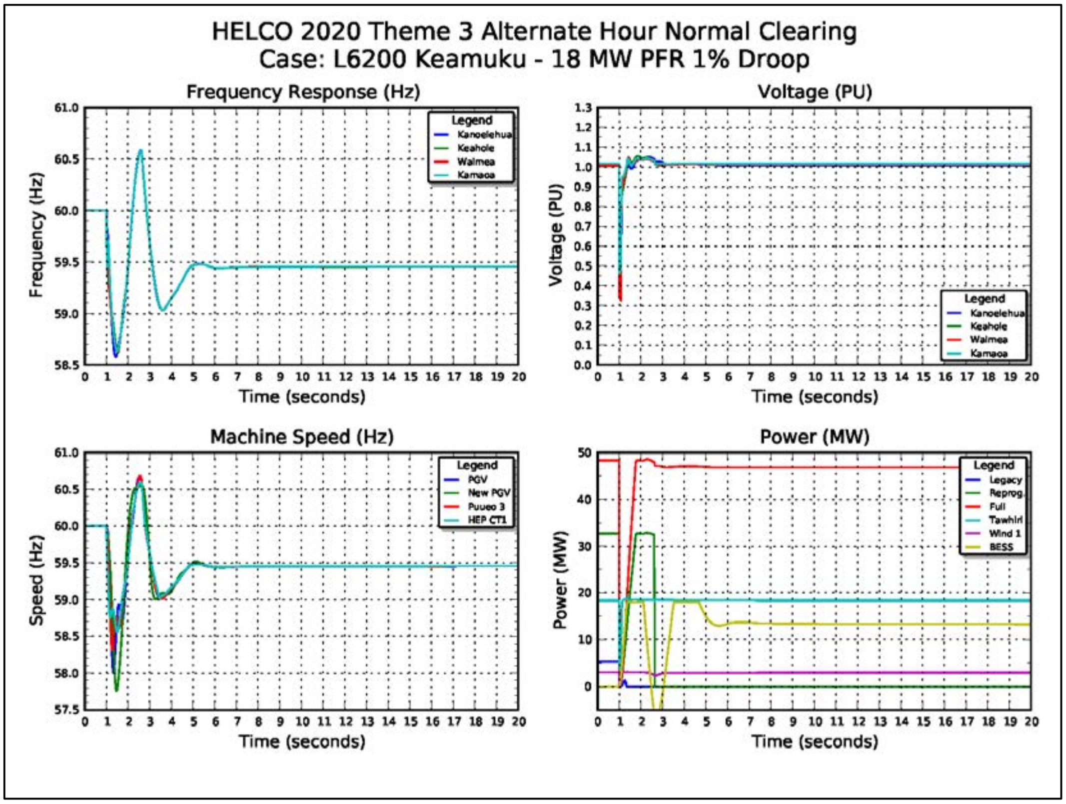

Figure O-362. Normally Cleared Fault Sensitivity 18 MW PFR

Figure O-362 shows system performance with the addition of 18 MW PFR at 1% droop response. For the purpose of this analysis, an 18 MW BESS was located at the Anaehoʻomalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, the Tawhiri wind plant, and the 18 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawaiʻi, the critical busses with the highest MVAR demand are the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					Theme 3 -QV Dispatch Sat 2/27/21 Hour 19		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146	22.0	3.0	15.0
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	48.6	11.4	30.1
Hill 5	13.5	5.0	2.20	15.6	34	13.5	0.0	8.5
Hill 6	20.5	8.0	2.53	27.5	70	20.0	0.5	12.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	17.1	2.9	10.1
Synch. Cond. 1	0.0	0.0	2.00	15.6	31			
Synch. Cond. 2	0.0	0.0	2.00	18.8	38			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	7.7		
Apollo	20.5	0.0						
HRD	10.5	0.0				0.8		
Hydro	16.8	0				10		
Wind	31.0	0				1		
DG-PV	133.8	0						
Total Kinetic Energy						774		
Total Load						168		
Total Thermal Generation						158		
Total Renewable Generation						10		
Total Storage						0		
Total Generation						168		
Excess Generation						0		
Total Up Regulation						19		
Total Down Regulation						90		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.1
	60.5Hz Capacity			56.6		60.5Hz Output		0.6

Table O-161. Unit Commitment and Dispatch 2021 QV Analysis

Table O-161 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		Theme 3 - QV MVAR Capability Sat 2/27/21 Hour 19		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	30.4	-19.6	1.0	29.4	-20.5
Keahole STCC	31.6	-23.1	27.5	4.1	-50.6
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	51.9	-30.5	-1.1	53.0	-29.4
Hill 5	6.1	-5.5	1.5	4.6	-7.1
Hill 6	13.3	-11.4	2.7	10.6	-14.1
Puna	6.7	-6.2			
Keah CT2	15.0	-11.5			
Puna CT3	15.6	-11.0	-5.5	21.2	-5.5
Synch. Cond. 1	11.6	-9.4			
Synch. Cond. 2	14.3	-8.9			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2			
HRD	4.0	-4.0	0.1	3.9	-4.1
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			26.1		
Total Renewable MVAR Generation			0.1		
Total Cap Bank MVAR			32.4		
Charging MVAR			16.2		
Total MVAR Supply			74.8		
Total MVAR Load			42.3		
Total MVAR Losses			32.5		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				127	
Total MVAR Absorb Capability					-131.3

Table O-162. MVAR Capability 2021 QV Analysis

Table O-162 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina
37	L7700 Waimea
48	L8600 Kealia-Kahaluu
49	L8600 Kealia

Table O-163. N-1 Contingencies2021 QV Analysis

Table O-163 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

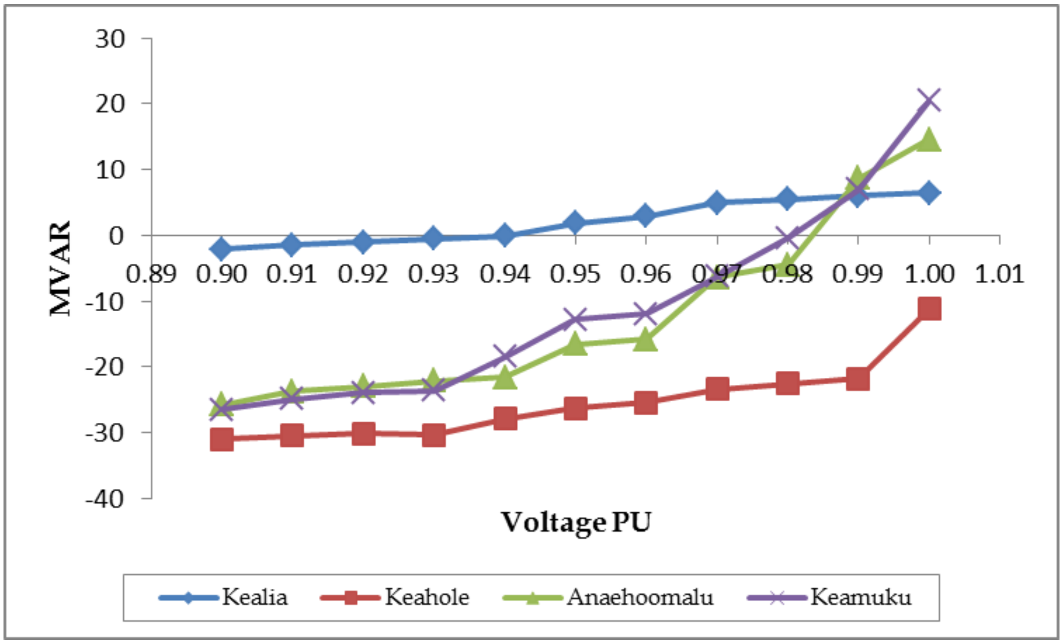

Figure O-363. QV Curves 2021

Figure O-363 shows the QV curves for the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The Kealia bus requires 2 MVAR to maintain bus voltage at 0.95 PU. For the purpose of this analysis, the unit commitment and dispatch meets the reactive power requirements of the system.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	50	6	50	6	50	5	50	5	50	3	50	2	50	0	50	-1	50	-1	50	-2	50	-2
8400	Keahole	36	-11	36	-22	36	-23	36	-23	36	-25	36	-26	36	-28	36	-30	36	-30	36	-31	36	-31
8500	Anaehoomalu	36	15	36	9	45	-5	36	-6	55	-16	36	-17	36	-22	36	-22	36	-23	36	-24	36	-26
8700	Keamuku	36	20	36	7	36	0	36	-6	36	-12	36	-13	36	-19	36	-24	36	-24	36	-25	36	-27

Table O-164. Results 2021 QV Analysis

Table O-164 shows the summary of results for the 2021 QV analysis. The Kealia bus requires 5 MVAR to maintain bus voltage at 0.95 PU for an outage of L8600.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

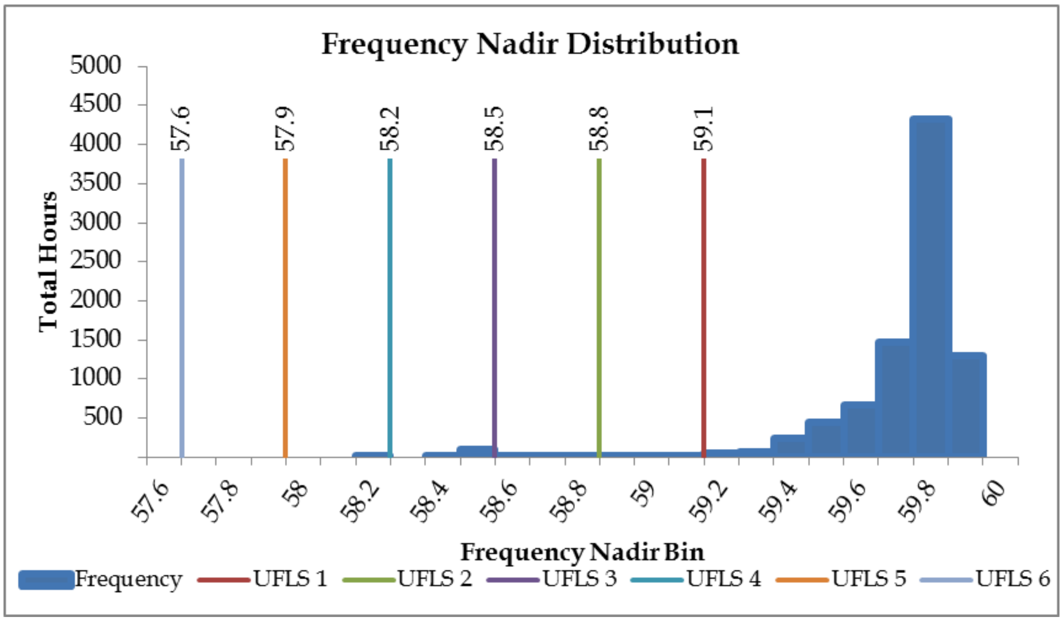

Figure O-364. Frequency Nadir Histogram for 2021

Figure O-364 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A typical hour was selected from the maximum distribution of 95 hours was 1:00 PM on Wednesday, June 23. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

The boundary hour selected from a distribution of one hour was 11:00 AM on Sunday, March 3. The frequency nadir range for the boundary hour is 58.1 – 58.2 Hz that requires four blocks of UFLS to stabilize system frequency.

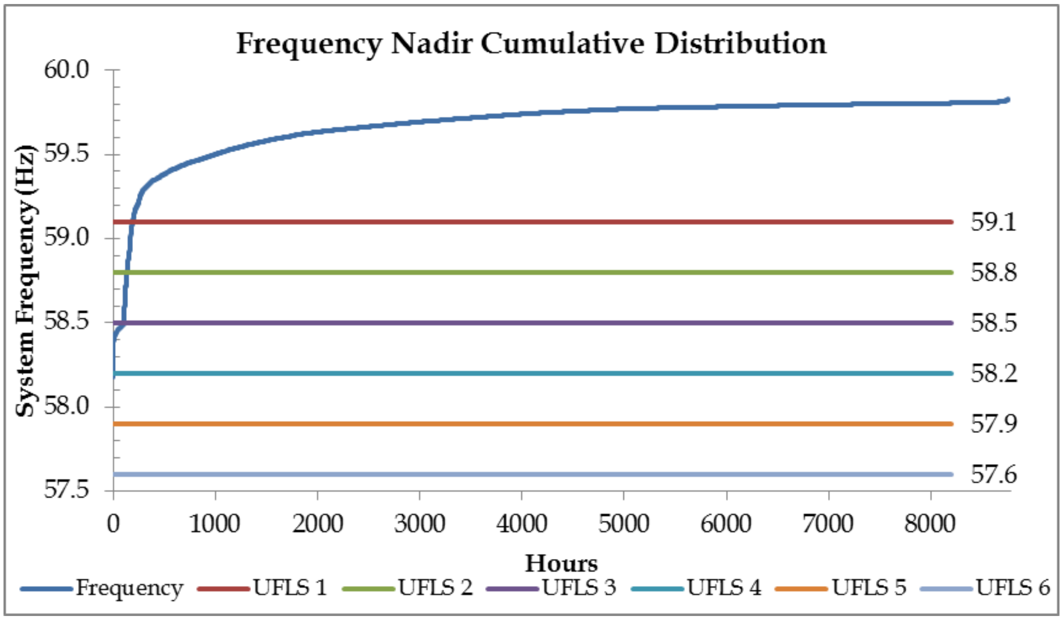

Figure O-365. Frequency Nadir Duration Curve 2021

Figure O-365 shows the frequency nadir duration curve for the Theme 3 resource plan in 2021. The system is at risk of exceeding the UFLS requirements of TPL-001 for 103 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Typical Wed 6/23/21 Hour 13			Theme 3 - HEP STCC Trip Boundary Wed 3/3/21 Hour 11		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146						
Keahole DTCC	54.0	7.0	2.77	71.8	199						
Keahole CT4	20.0	7.0	2.10	25.2	53						
Keahole CT5	20.0	7.0	2.10	25.2	53						
HEP STCC	28.5	9.0	1.96	58.9	116	25.9	2.6	16.9	24.7	3.8	15.7
HEP DTCC	60.0	18.5	1.78	94.4	168						
Hill 5	13.5	5.0	2.20	15.6	34						
Hill 6	20.5	8.0	2.53	27.5	70						
Puna	15.5	6.0	4.63	18.8	87						
Keah CT2	13.8	5.0	4.44	22.2	99						
Puna CT3	20.0	7.0	4.96	29.6	147						
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.		0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.		0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.6			3.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.7			3.6		
Apollo	20.5	0.0				14.6			7.5		
HRD	10.5	0.0				8.8			0.5		
Wind1	20.0	0.0				10.0			2.0		
Hydro	16.8	0				5			7		
Wind	31.0	0				33			10		
DG-PV	133.8	0				71			83		
Total Kinetic Energy						394			394		
Total Load						172			162		
Total Thermal Generation						62			61		
Total Renewable Generation						110			100		
Total Storage						0			0		
Total Generation						172			162		
Excess Generation						0			0		
Total Up Regulation						4			5		
Total Down Regulation						31			30		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.3	59.3Hz Output		5.2
	60.5Hz Capacity			56.6		60.5Hz Output		30.6	60.5Hz Output		36.8

Table O-165. Unit Commitment and Dispatch 2021

Table O-165 shows the unit commitment and dispatch for the typical hour (6/23/21, 1:00 PM) and boundary hour (3/3/21, 11:00 AM).

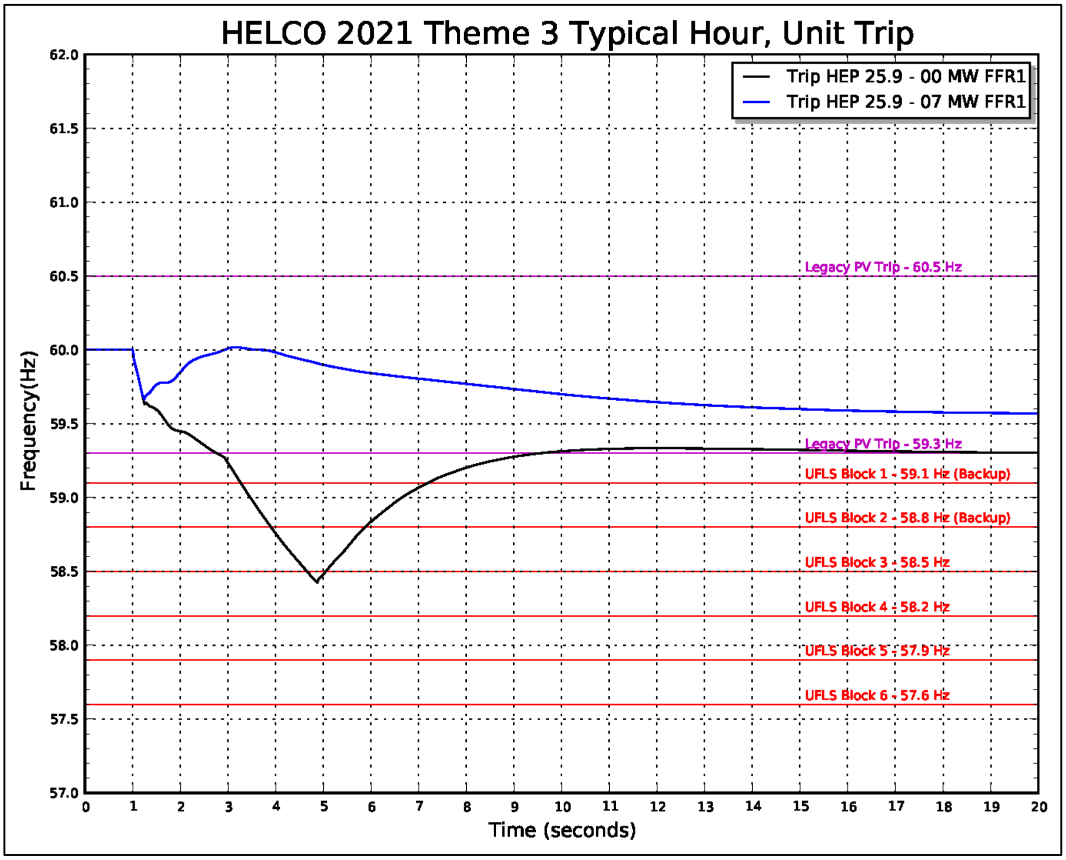

Figure O-366. Frequency Response Profile for FFR1 Typical Hour

Figure O-366 shows the frequency response profile for a HEP trip at 26 MW. System kinetic energy is 326 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 4 MW. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

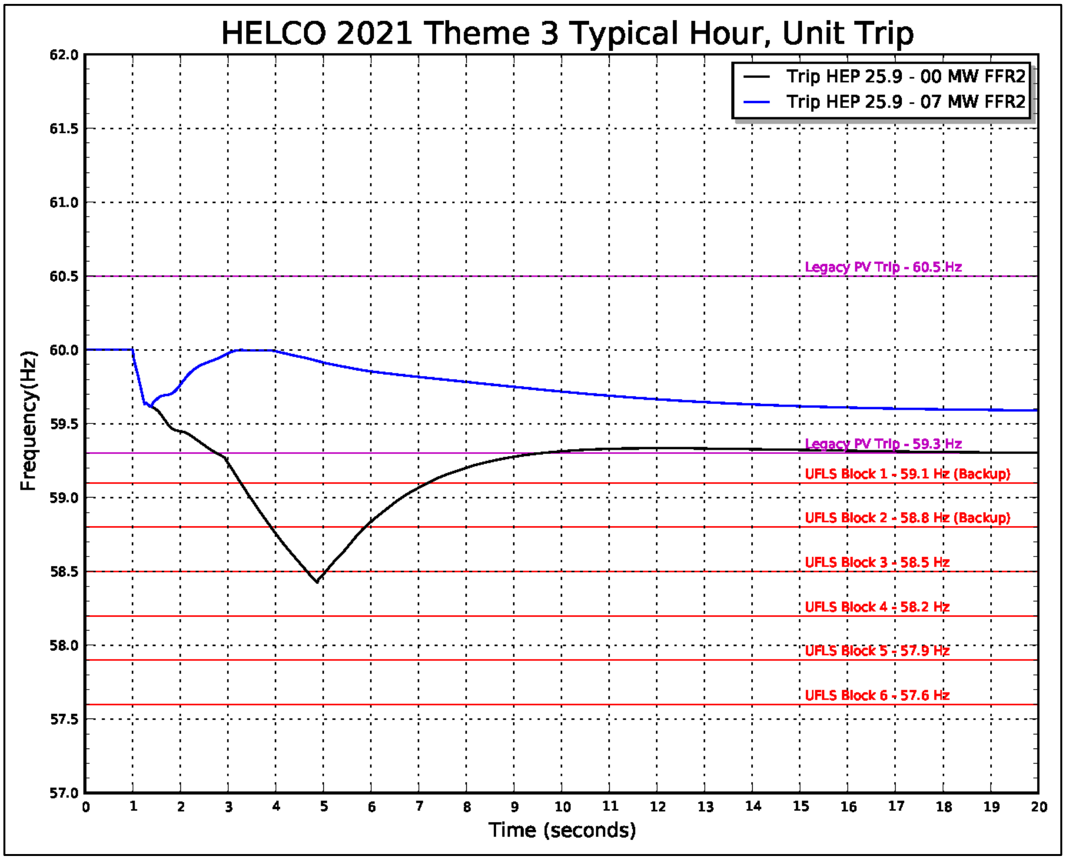

Figure O-367. Frequency Response Profile for FFR2 Typical Hour

Figure O-367 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 7 MW.

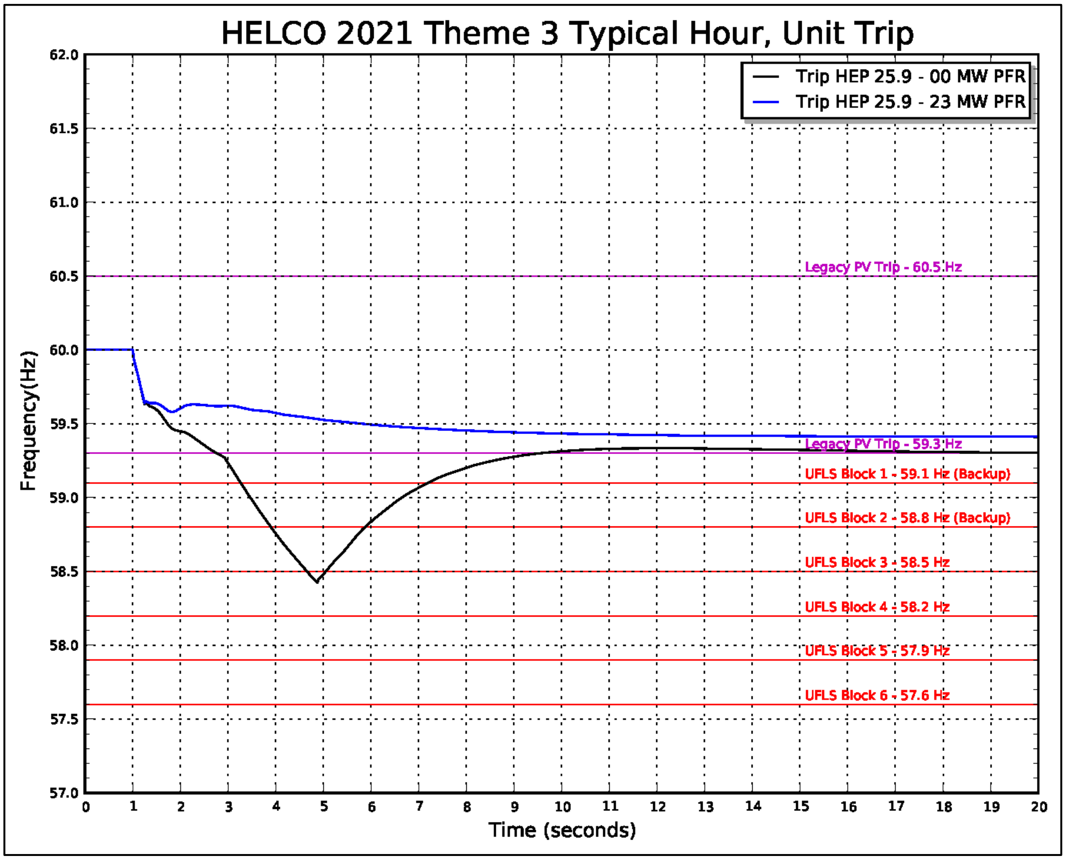

Figure O-368. Frequency Response Profile for PFR Typical Hour

Figure O-368 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 23 MW. This is in addition to the 4 MW of from thermal generation.

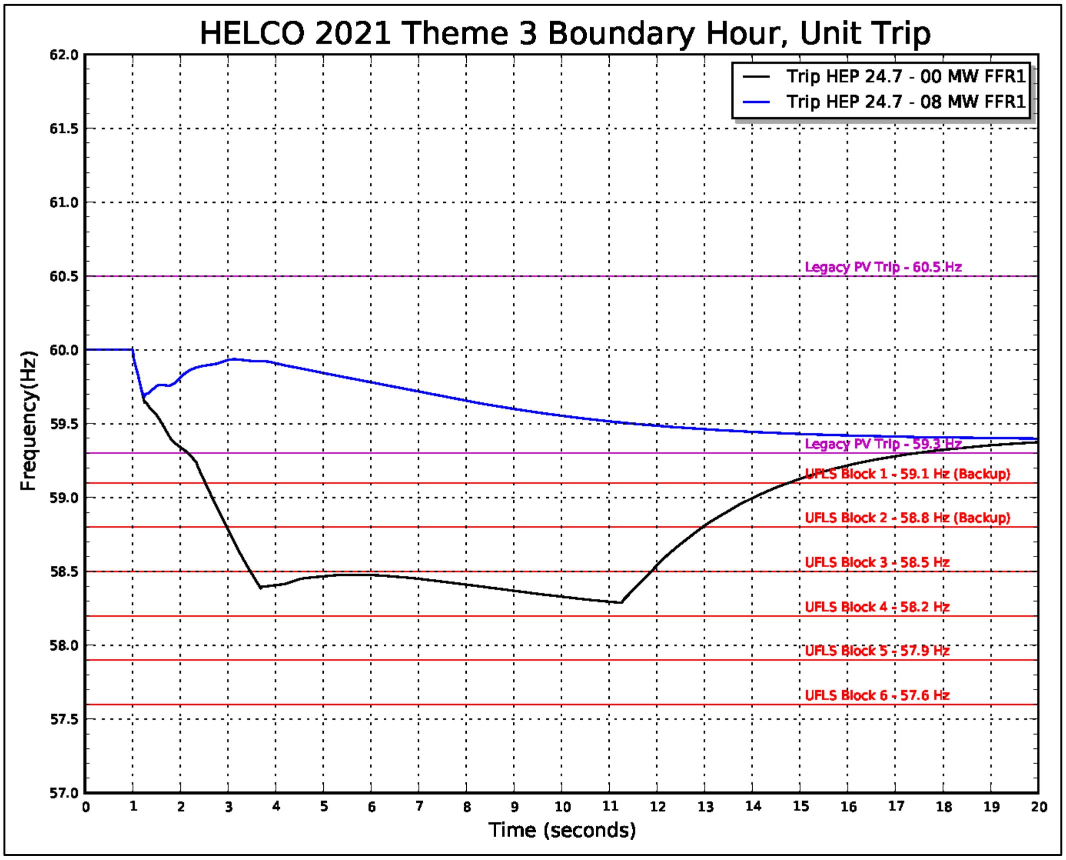

Figure O-369. Frequency Response Profile for FFR1 Boundary Hour

Figure O-369 shows the frequency response profile for a HEP trip at 25 MW. System kinetic energy is 326 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 5 MW. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

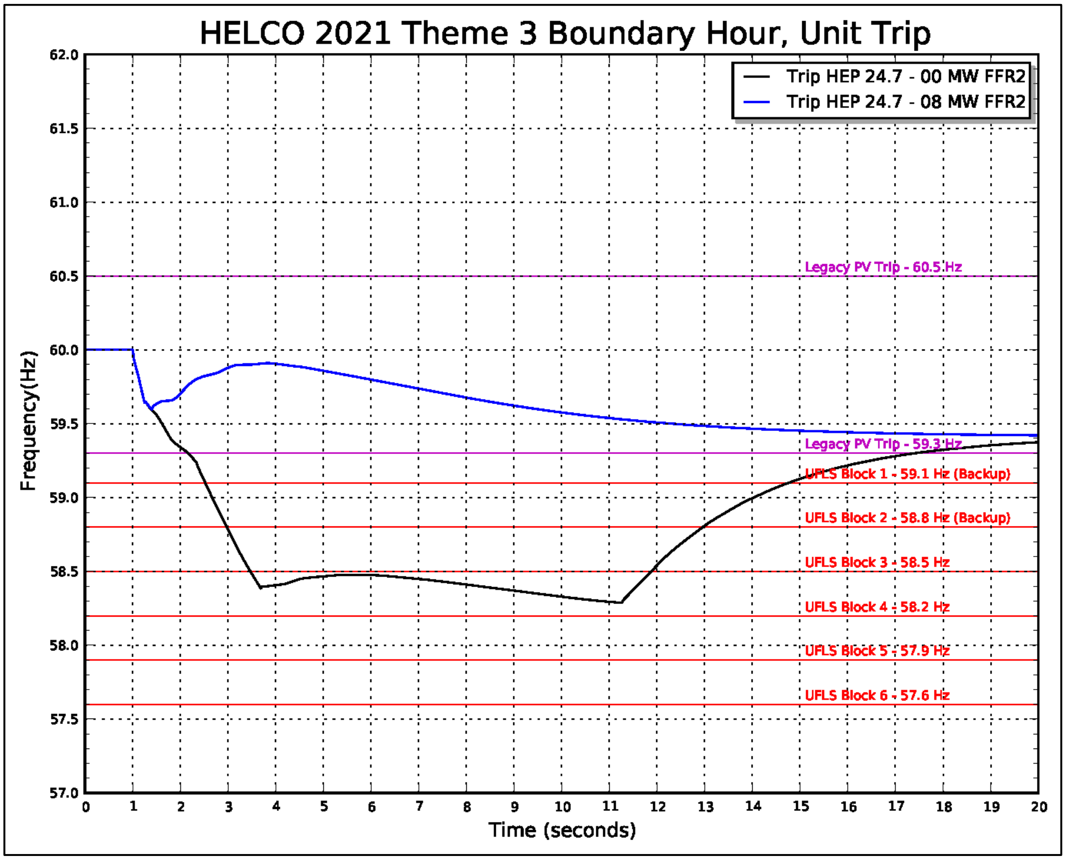

Figure O-370. Frequency Response Profile for FFR2 Boundary Hour

Figure O-370 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 8 MW.

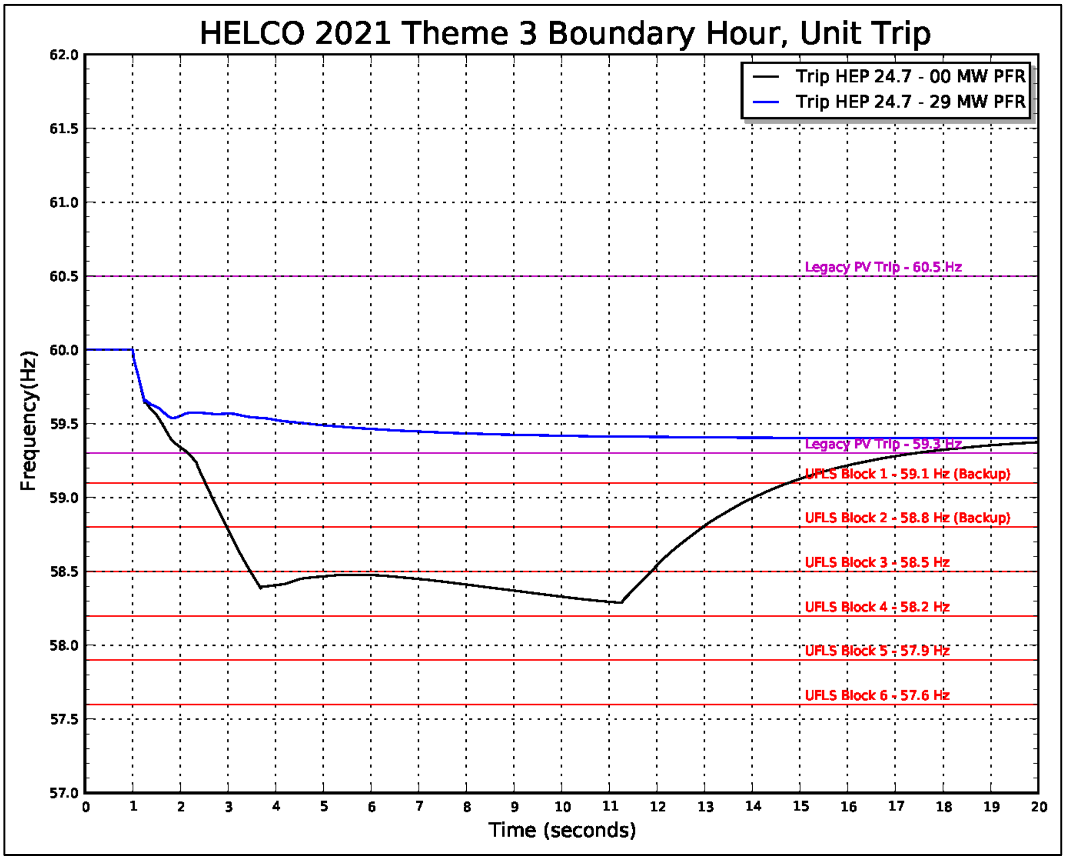

Figure O-371. Frequency Response Profile for FFR1 Boundary Hour

Figure O-371 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 2 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					Theme 3 - Fault Sat 2/6/21 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	33.1	4.9	11.1
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	11.2	17.3	2.2
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.9		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				18.3		
HRD	10.5	0.0				2.6		
Wind1	20.0	0.0				3.5		
Hydro	16.8	0				2		
Wind	31.0	0				24		
DG-PV	133.8	0				87		
Total Kinetic Energy							365	
Total Load							158	
Total Thermal Generation							44	
Total Renewable Generation							114	
Total Storage							0	
Total Generation							158	
Excess Generation							0	
Total Up Regulation							22	
Total Down Regulation							13	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		5.4
	60.5Hz Capacity			56.6		60.5Hz Output		38.5

Table O-166. Unit Commitment and Dispatch Fault Analysis

Table O-166 shows the unit commitment and dispatch for the 69 kV fault analysis (2/6/20, 1:00 PM).

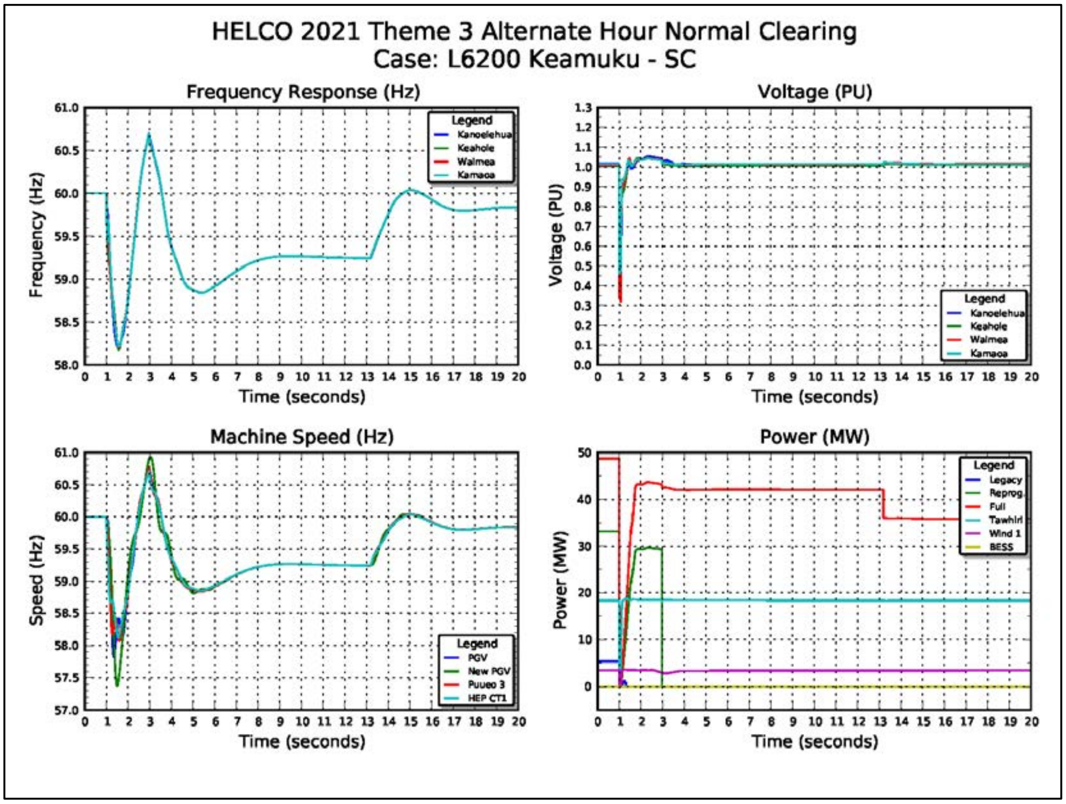

Figure O-372. System Performance Normally Cleared Fault

Figure O-372 shows the system performance for a normally cleared fault at the Keamuku end of the L6200 circuit. System voltage is suppressed below the 0.5 PU low voltage ride-through threshold for inverter-based PV generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 87 MW from the system. System frequency decays while system voltage is quickly restored when the fault is cleared. Generation from some DG-PV is restored when system voltage recovers but system frequency continues to decay. The aggregate frequency response from synchronous units, DG-PV restoration, and four blocks of UFLS is able to stabilize system frequency at 58.2 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to improve system security. Results will vary for different circuits and dispatch schedules. Further analysis is required to determine an optimal solution to ensure system security.

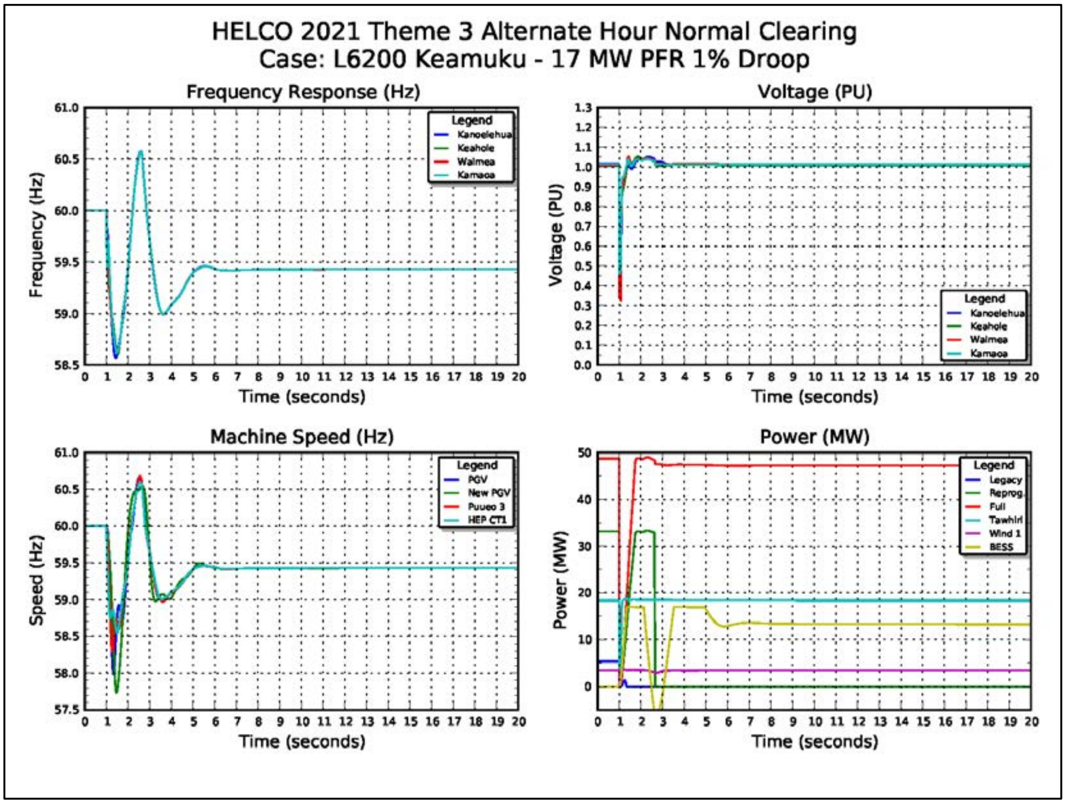

Figure O-373. Normally Cleared Fault Sensitivity 17 MW PFR

Figure O-373 shows system performance with the addition of 17 MW PFR at 1% droop response. For the purpose of this analysis, a 17 MW BESS was located at the Anaehoʻomalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, the Tawhiri wind plant, and the 17 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

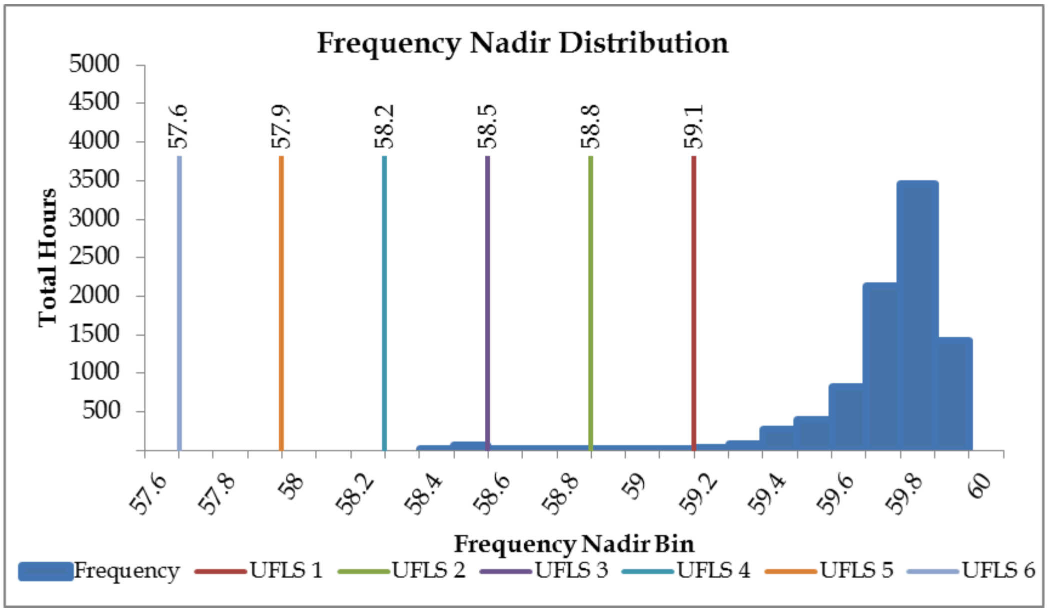

Figure O-374. Frequency Nadir Histogram for 2025

Figure O-374 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A boundary hour was selected from the maximum distribution of 71 hours was 1:00 PM on Sunday, January 19. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

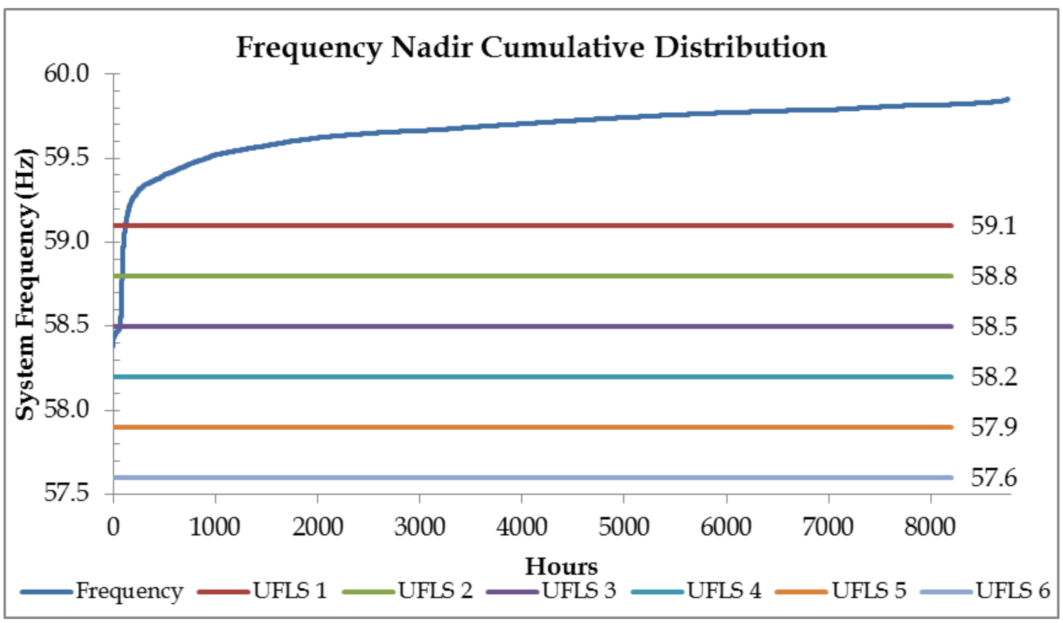

Figure O-375. Frequency Nadir Duration Curve 2025

Figure O-375 shows the frequency nadir duration curve for the Theme 3 resource plan in 2025. The system is at risk of exceeding the UFLS requirements of TPL-001 for 71 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Boundary Sun 1/19/25 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.8	4.7	14.8
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Geo1	20.0		5.00	40.0	200	20.0	0.0	20.0
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.5		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.9		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				4		
Wind	31.0	0				0		
DG-PV	143.0	0				79		
Total Kinetic Energy						594		
Total Load						164		
Total Thermal Generation						80		
Total Renewable Generation						83		
Total Storage						0		
Total Generation						164		
Excess Generation						0		
Total Up Regulation						6		
Total Down Regulation						49		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.4
	60.5Hz Capacity			56.6		60.5Hz Output		31.7

Table O-167. Unit Commitment and Dispatch 2025

Table O-167 shows the unit commitment and dispatch for the boundary hour (1/19/25, 1:00 PM).

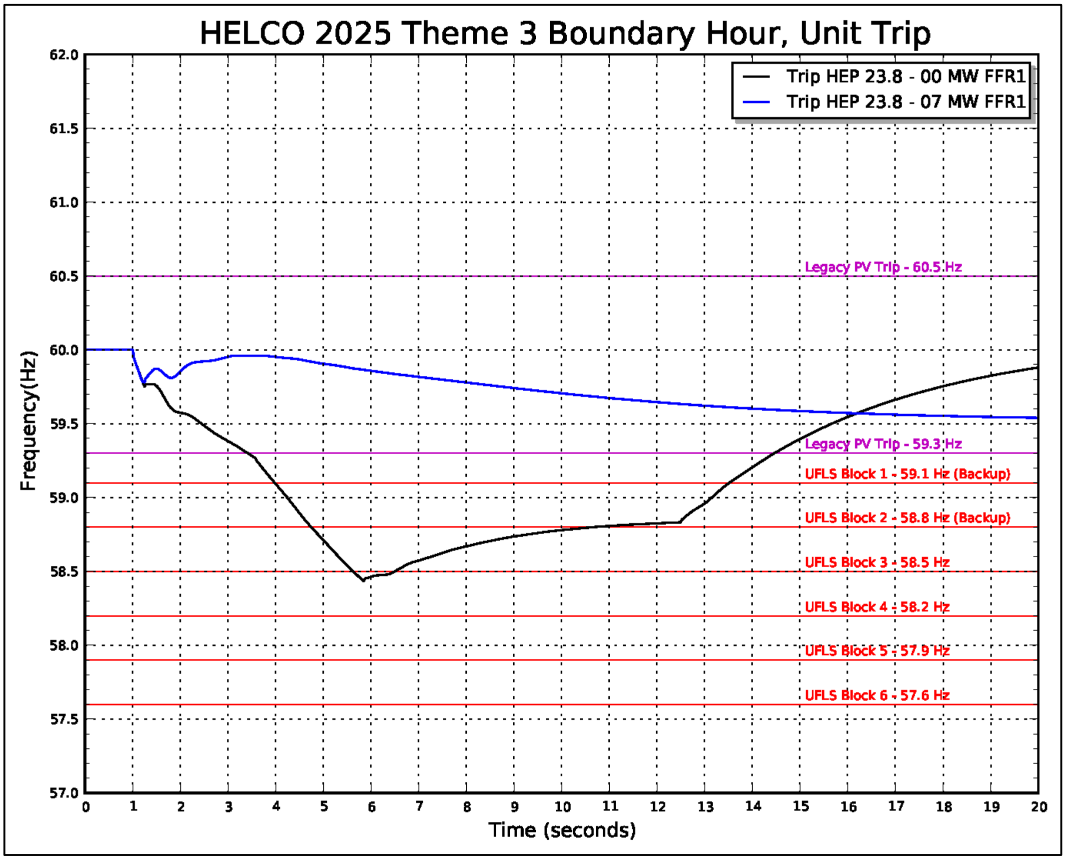

Figure O-376. Frequency Response Profile for FFR1 Boundary Hour

Figure O-376 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 526 MW-sec and the capacity of legacy PV that will disconnect from the system is approximately 4 MW. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

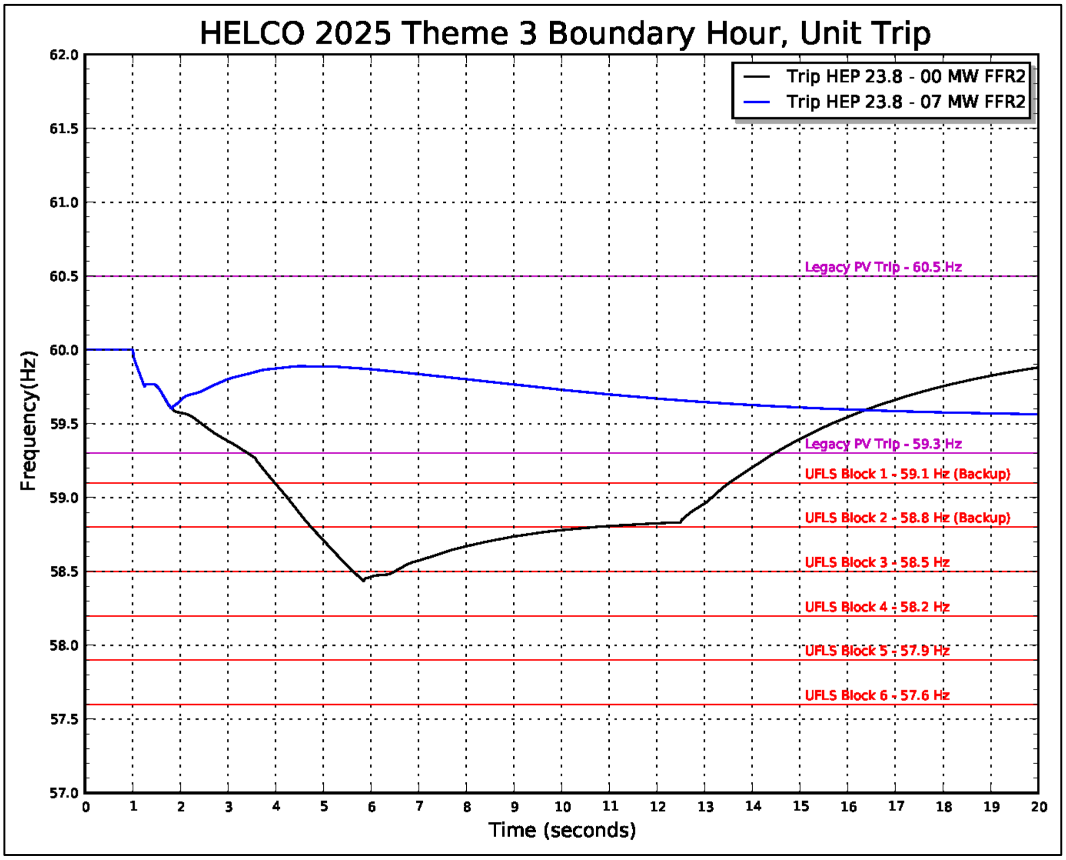

Figure O-377. Frequency Response Profile for FFR2 Boundary Hour

Figure O-377 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 7 MW.

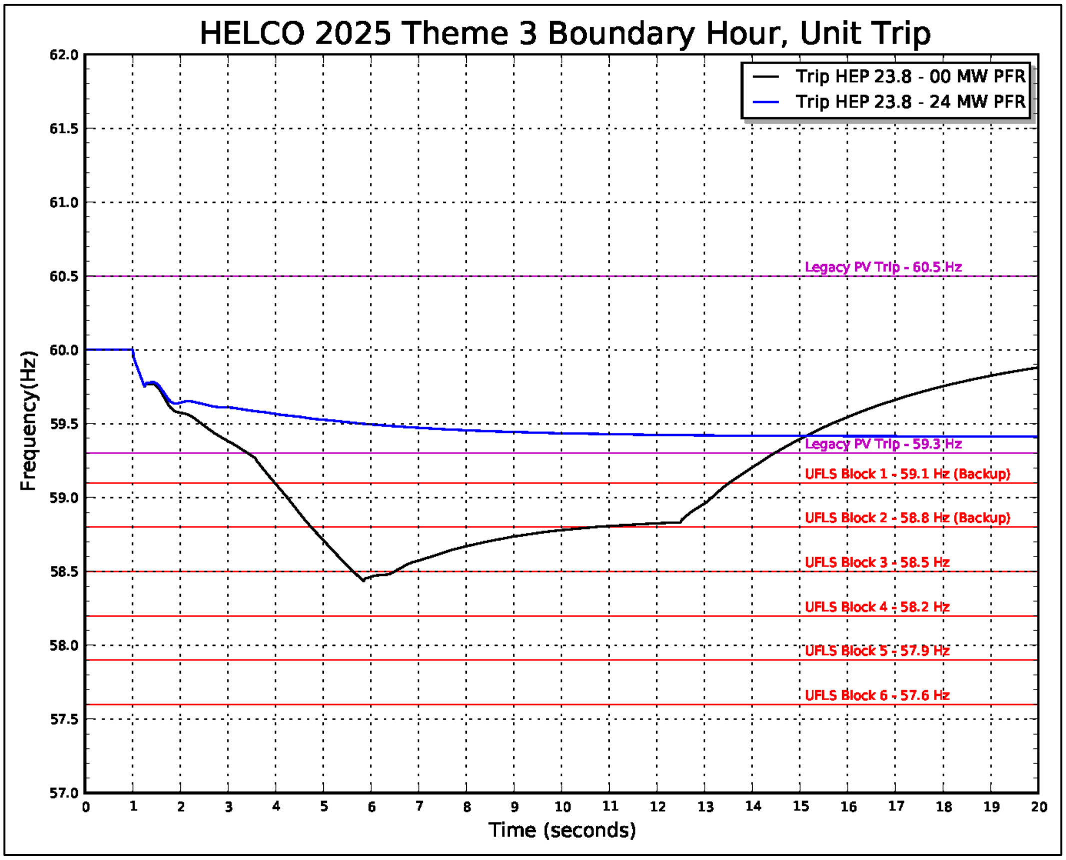

Figure O-378. Frequency Response Profile for PFR Boundary Hour

Figure O-378 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 24MW. This is in addition to the 6 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

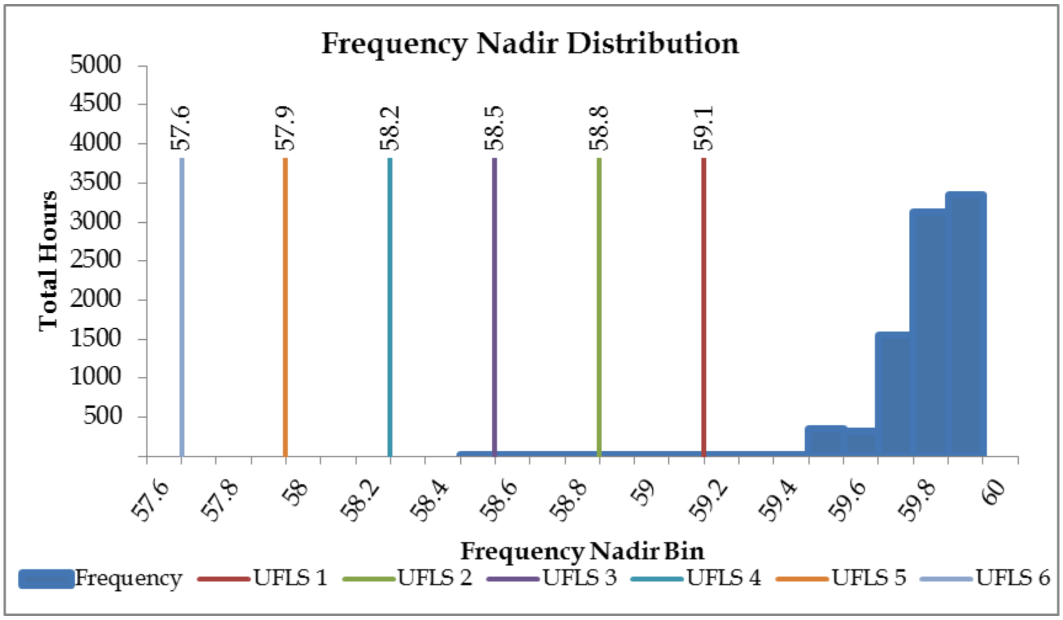

Figure O-379. Frequency Nadir Histogram for 2030

Figure O-379 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Theme 3 production cost simulations. A boundary hour was selected from the maximum distribution of 4 hours was 6:00 AM on Tuesday, April 30. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

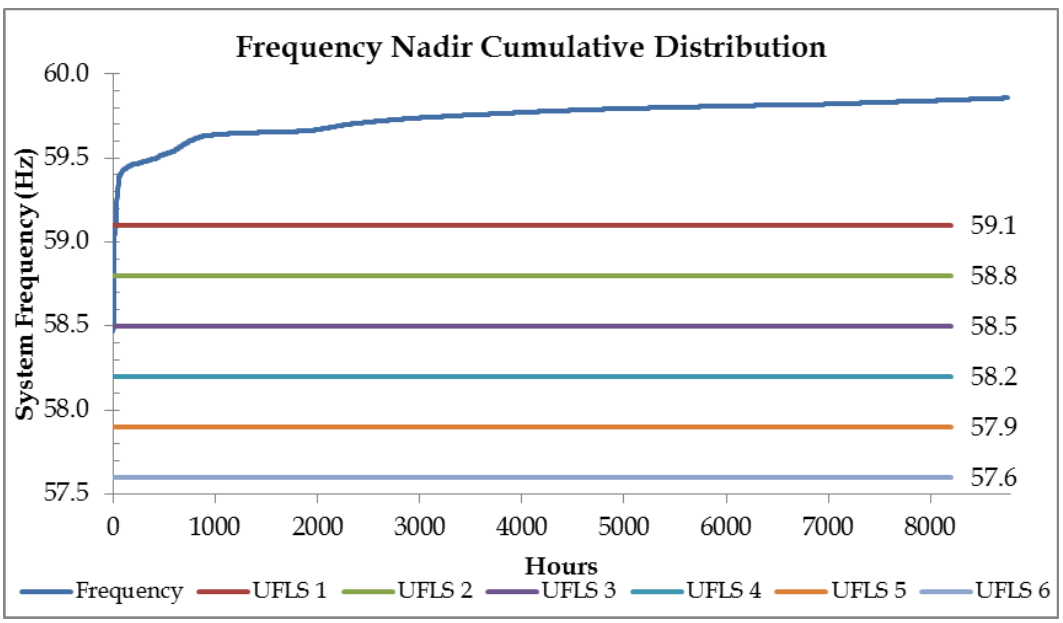

Figure O-380. Frequency Nadir Duration Curve 2030

Figure O-380 shows the frequency nadir duration curve for the Theme 3 resource plan in 2030. The system is at risk of exceeding the UFLS requirements of TPL-001 for 4 hours of the year.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Boundary Tuesday 4/30/30 Hour 6		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.4	1.6	14.4
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	26.4	2.1	17.4
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Geo1	20.0		5.00	40.0	200	20.0	0.0	20.0
Geo2	20.0		5.00	40.0	200	20.0	0.0	20.0
Biomass1	20.0		3.16	28.0	88			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	4.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	0.5		
Apollo	20.5	0.0				6.7		
HRD	10.5	0.0				0.8		
Wind1	20.0	0.0				4.0		
Wind2	20.0	0.0				4.0		
Hydro	16.8	0				5		
Wind	31.0	0				16		
DG-PV	154.3	0						
Total Kinetic Energy							794	
Total Load							123	
Total Thermal Generation							103	
Total Renewable Generation							20	
Total Storage							0	
Total Generation							123	
Excess Generation							0	
Total Up Regulation							4	
Total Down Regulation							72	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-168. Unit Commitment and Dispatch 2030

Table O-168 shows the unit commitment and dispatch for the boundary hour (4/30/30, 6:00 AM).

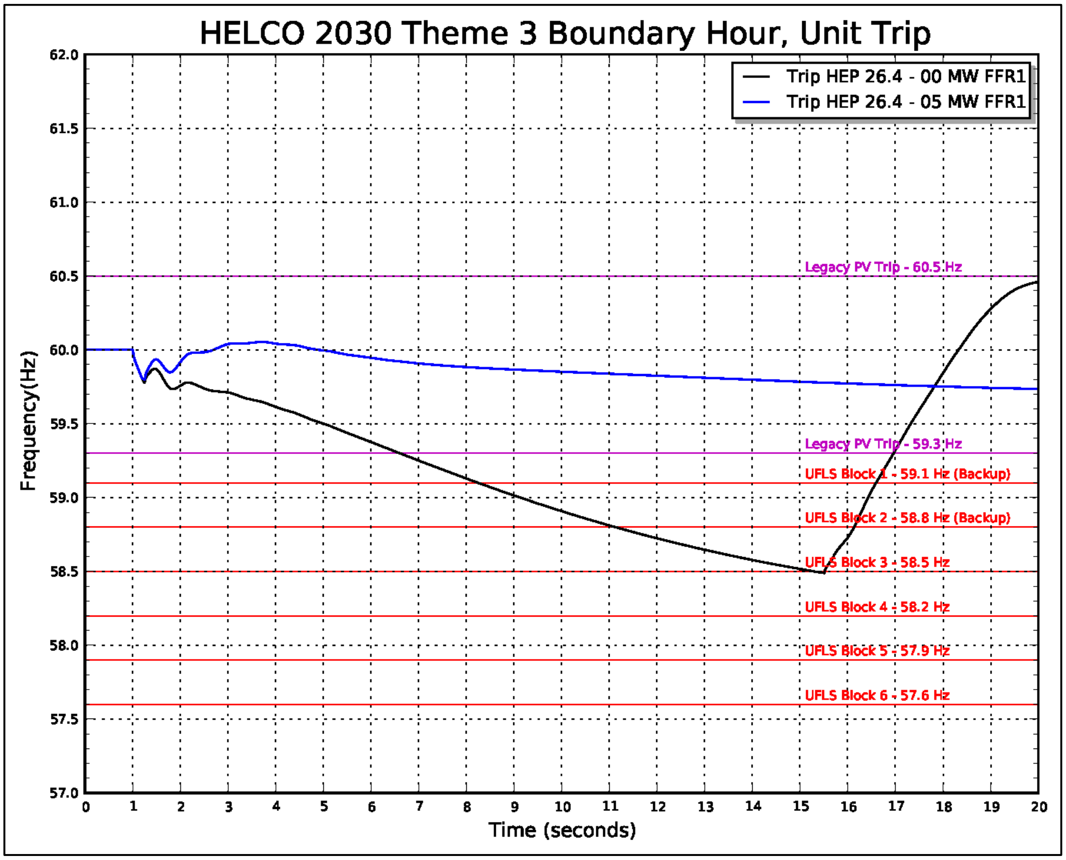

Figure O-381. Frequency Response Profile for FFR1 Boundary Hour

Figure O-381 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 794 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

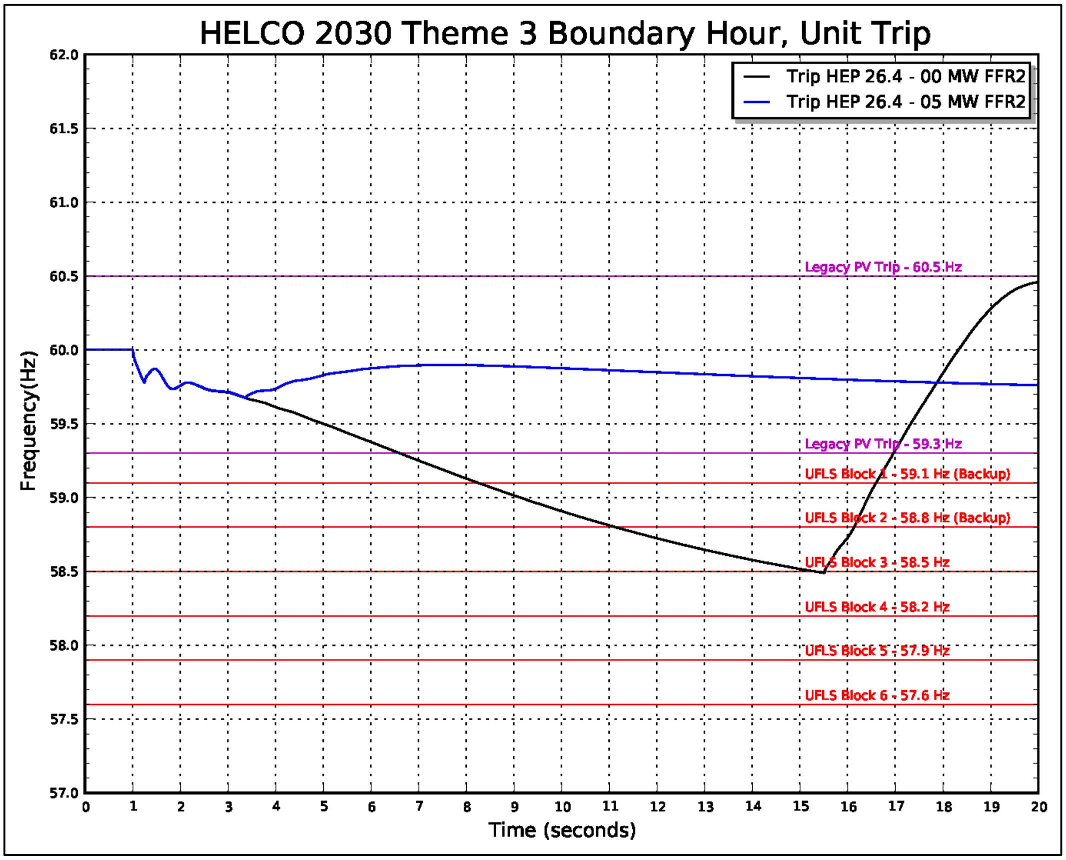

Figure O-382. Frequency Response Profile for FFR2 Boundary Hour

Figure O-382 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW.

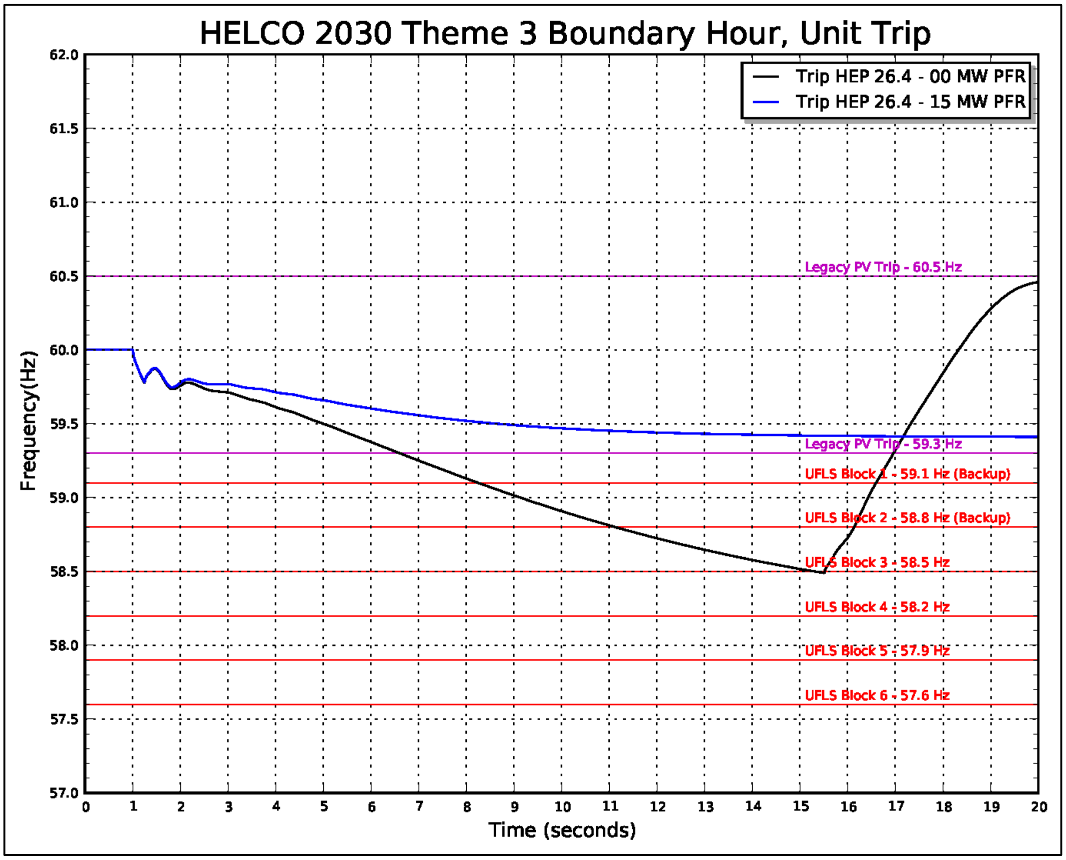

Figure O-383. Frequency Response Profile for PFR Boundary Hour

Figure O-383 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 15MW. This is in addition to the 4 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

Unit	Unit Ratings					Theme 3 - HEP STCC Trip Boundary Wed 3/21/45 Hour 4		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	36.9	1.1	14.9
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	25.7	2.8	16.7
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Geo1	20.0		5.00	40.0	200	20.0	0.0	20.0
Geo2	20.0		5.00	40.0	200			
Biomass1	20.0		3.16	28.0	88	18.0	2.0	18.0
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.1		
Apollo	20.5	0.0						
HRD	10.5	0.0				3.4		
Wind1	20.0	0.0						
Wind2	20.0	0.0						
Hydro	16.8	0				4		
Wind	31.0	0				3		
DG-PV	195.4	0						
Total Kinetic Energy							683	
Total Load							108	
Total Thermal Generation							101	
Total Renewable Generation							8	
Total Storage							0	
Total Generation							108	
Excess Generation							0	
Total Up Regulation							6	
Total Down Regulation							70	
Legacy DG-PV	59.3Hz Capacity			0.0		59.3Hz Output		0.0
	60.5Hz Capacity			0.0		60.5Hz Output		0.0

Table O-169. Unit Commitment and Dispatch 2045

Table O-169 shows the unit commitment and dispatch for the boundary hour (3/21/45, 4:00 AM).

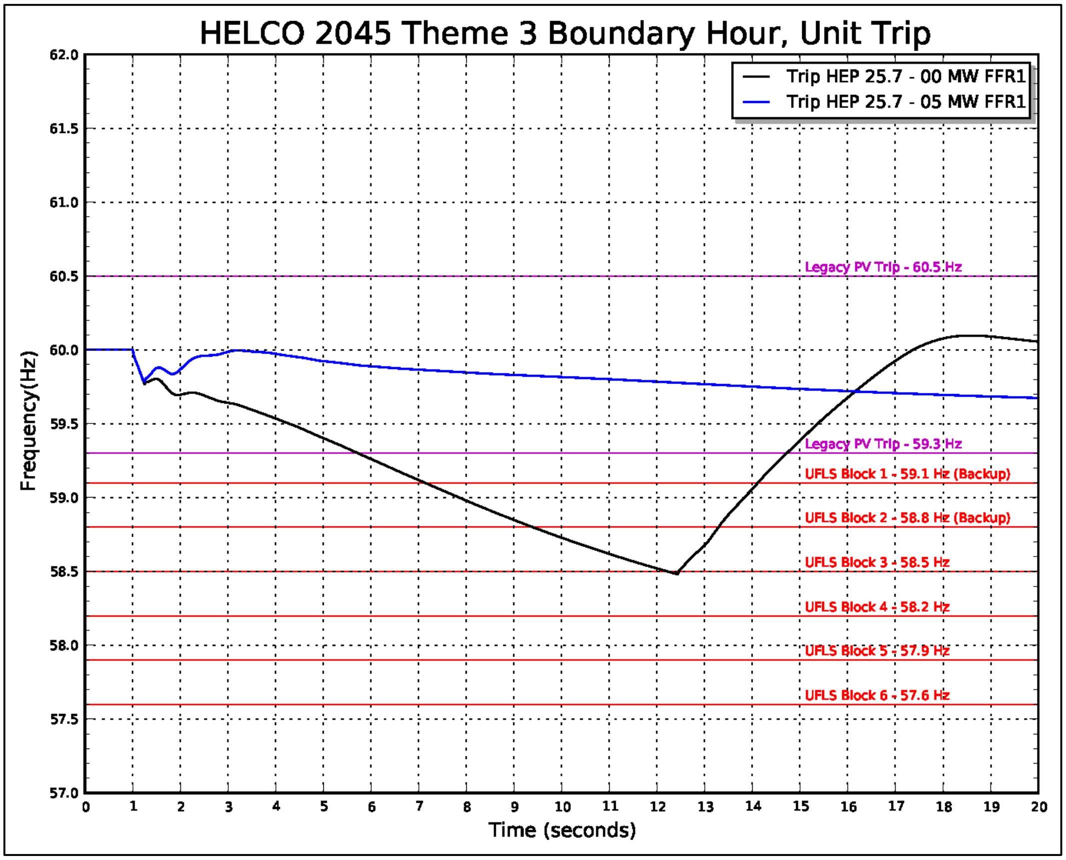

Figure O-384. Frequency Response Profile for FFR1 Boundary Hour

Figure O-384 shows the frequency response profile for a HEP trip at 24 MW. System kinetic energy is 683 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 5 MW.

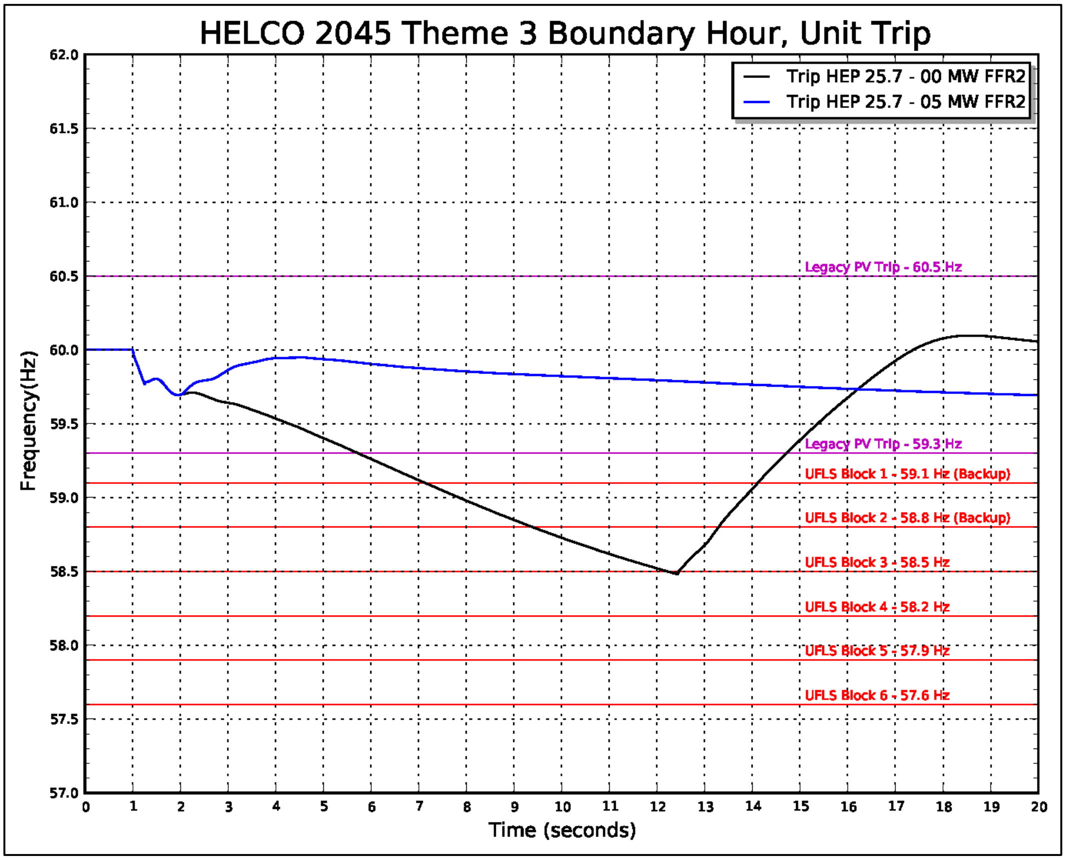

Figure O-385. Frequency Response Profile for FFR2 Boundary Hour

Figure O-385 shows the frequency response profile for the FFR2 analysis. The capacity of FFR2 required to bring the system into compliance with TPL-001 is 5 MW.

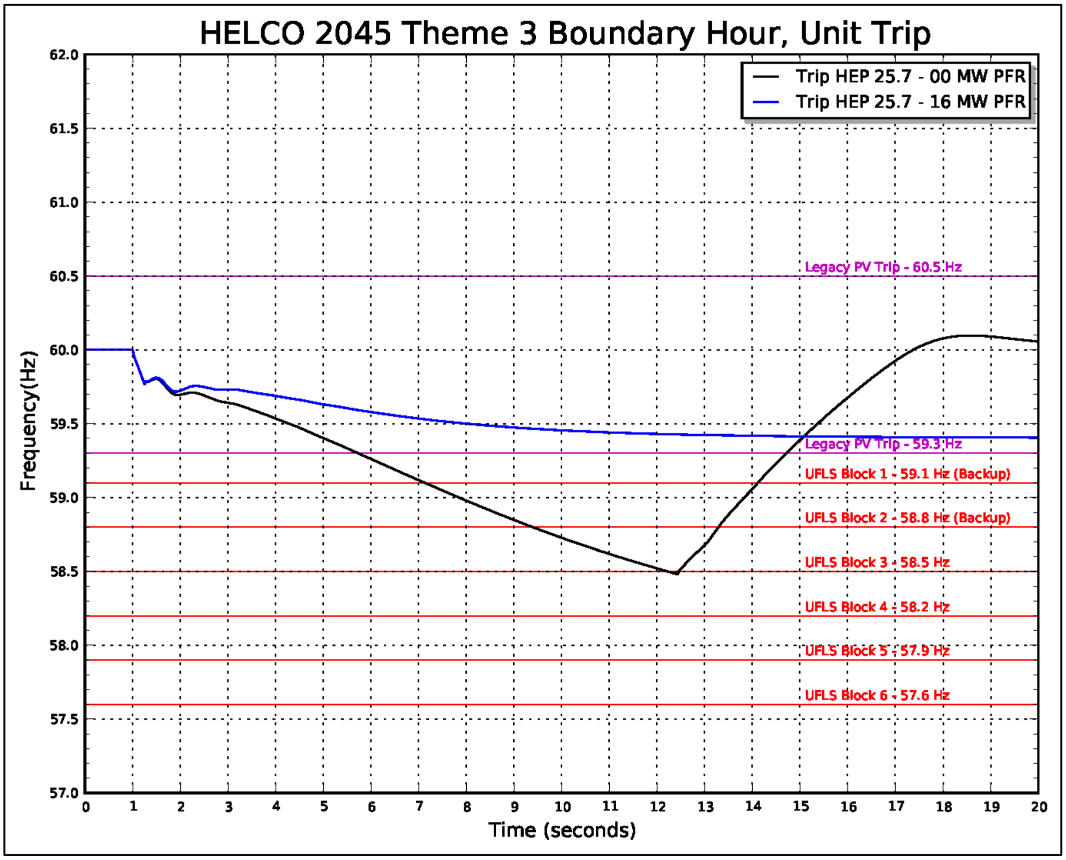

Figure O-386. Frequency Response Profile for PFR Boundary Hour

Figure O-386 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 16MW. This is in addition to the 6 MW of upward regulation from thermal generation.

Post April DR Plan

System security analysis performed on the Post April DR resource plan include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation analyses were performed for select years beyond 2021. Hawai'i does not have FFR2 capacities in their Demand Response portfolio.

2019

System security analysis performed on the Post April DR resource plan to bring the system into compliance with TPL-001.

QV Analysis

The Hawai'i transmission system is designed to operate with one transmission lines out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purposes of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability. Reactive power demand increases with system load and transmission line contingencies. Resources that provide MVARs include the following:

- Synchronous generators
- Synchronous condensers
- Capacitor banks
- Static volt-amp reactive compensators
- Dynamic volt-amp reactive systems

Of these resources, only synchronous generators and synchronous condensers provide the fault current to meet the minimum requirement of 80 MVA on the 69 kV transmission system of which 25 MVA must be connected on the West side of the island. Therefore, only synchronous condensers are evaluated in these analyses.

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawaiʻi, the critical busses with the highest MVAR demand are the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR- QV Dispatch Wed 9/25/19 Hour 22		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	33.0	5.0	11.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	58.0	2.0	39.5
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	17.3	3.2	9.3
Puna	15.5	6.0	4.63	18.8	87	12.0	3.5	6.0
Kano CT1	10.5	0.5	4.44	13.5	60			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	11.7	8.3	4.7
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0				1.8		
HRD	10.5	0.0				1.9		
Hydro	16.8	0				2		
Wind	91.0	0				4		
DG-PV	117.7	0						
Total Kinetic Energy						651		
Total Load						138		
Total Thermal Generation						132		
Total Renewable Generation						6		
Total Storage						0		
Total Generation						138		
Excess Generation						0		
Total Up Regulation						22		
Total Down Regulation						71		
Legacy DG-PV	59.3Hz Capacity		7.9			59.3Hz Output		0.0
	60.5Hz Capacity		56.6			60.5Hz Output		0.0

Table O-170. Unit Commitment and Dispatch 2019 QV Analysis

Table O-170 shows the unit commitment and dispatch for the 2019 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR- QV MVAR Capability Wed 9/25/19 Hour 22		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	31.6	-20.1	-2.3	33.9	-17.9
Keahole STCC	27.9	-19.4			
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	48.0	-28.1	-3.1	51.1	-25.0
Hill 5	6.1	-5.5			
Hill 6	14.7	-12.4	-3.0	17.7	-9.4
Puna	11.0	-7.9	2.1	8.9	-10.1
Kano CT1	7.1	0.0			
Keah CT2	15.0	-11.5			
Puna CT3	17.3	-12.1	3.4	13.9	-15.4
Diesels (x9)	20.3	-12.3			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2	-0.2	5.4	-9.9
HRD	4.0	-4.0	-1.6	5.6	-2.4
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			-2.8		
Total Renewable MVAR Generation			-1.8		
Total Cap Bank MVAR			49.6		
Charging MVAR			16.2		
Total MVAR Supply			61.1		
Total MVAR Load			32.3		
Total MVAR Losses			28.7		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				136	
Total MVAR Absorb Capability					-90.1

Table O-171. MVAR Capability 2019 QV Analysis

Table O-171 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
35	L7700 Haina-Waimea
36	L7700 Haina
50	L8600 Kahaluu

Table O-172. N-1 Contingencies 2019 QV Analysis

Table O-172 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

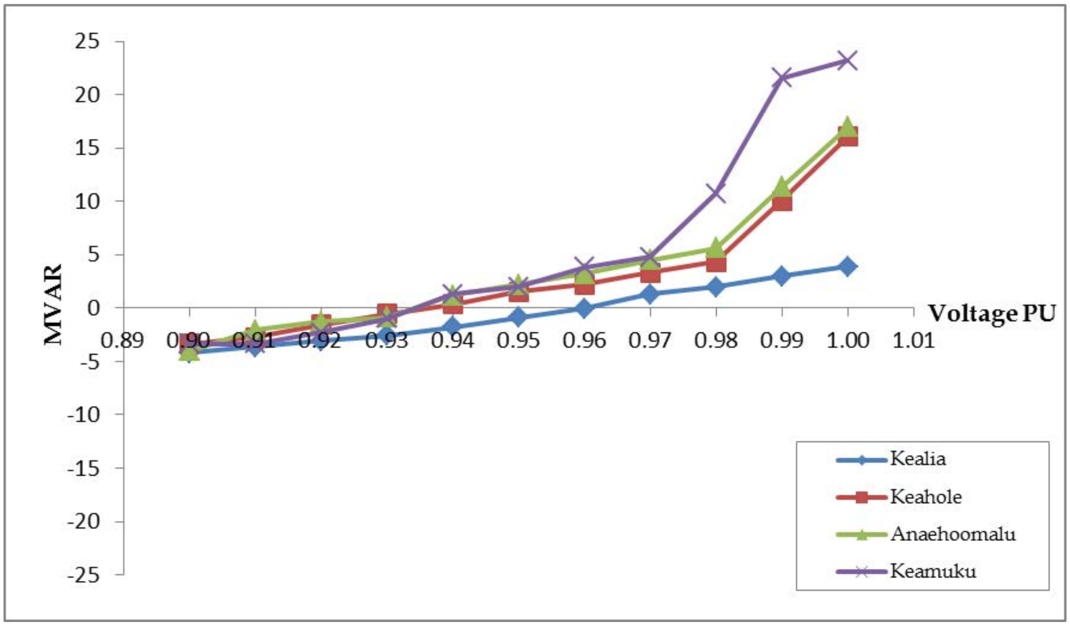

Figure O-387. QV Curves 2019

Figure O-387 shows the QV curves for the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. The Anaehoʻomalu, Keahole, and Keamuku busses require 2 MVAR to maintain bus voltage at 0.95 PU. For the purpose of this analysis, the reactive power requirements of the system are met.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	4	36	3	36	2	36	1	36	0	36	-1	36	-2	50	-3	50	-3	50	-4	50	-4
8400	Keahole	36	16	36	10	36	4	36	3	36	2	36	2	36	0	36	-1	36	-2	36	-3	36	-3
8500	Anaehoomalu	35	17	36	11	36	6	36	4	36	3	36	2	36	1	36	-1	36	-1	36	-2	36	-4
8700	Keamuku	36	23	36	22	36	11	36	5	36	4	36	2	36	1	36	-1	36	-2	36	-3	36	-3

Table O-173. Summary of Results 2019 QV Analysis

Table O-173 shows the results of the QV analysis with the additional synchronous condensers. The Anaehoʻomalu and Keamuku busses require 2 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

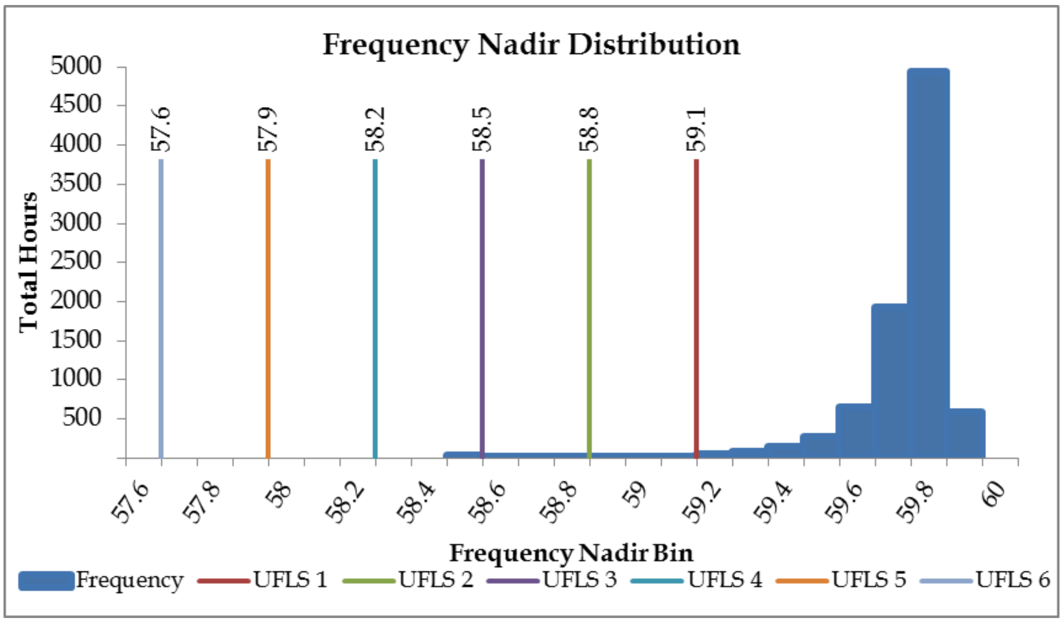

Figure O-388. Frequency Nadir Histogram for 2019

Figure O-388 is a histogram of the expected frequency nadirs for N-1 generator contingency events for the entire year from the Post April DR production cost simulations. The boundary hour selected from a maximum distribution of 35 hours was 1:00 AM on Sunday, September 15. The frequency nadir range for the typical hour is 58.4 - 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

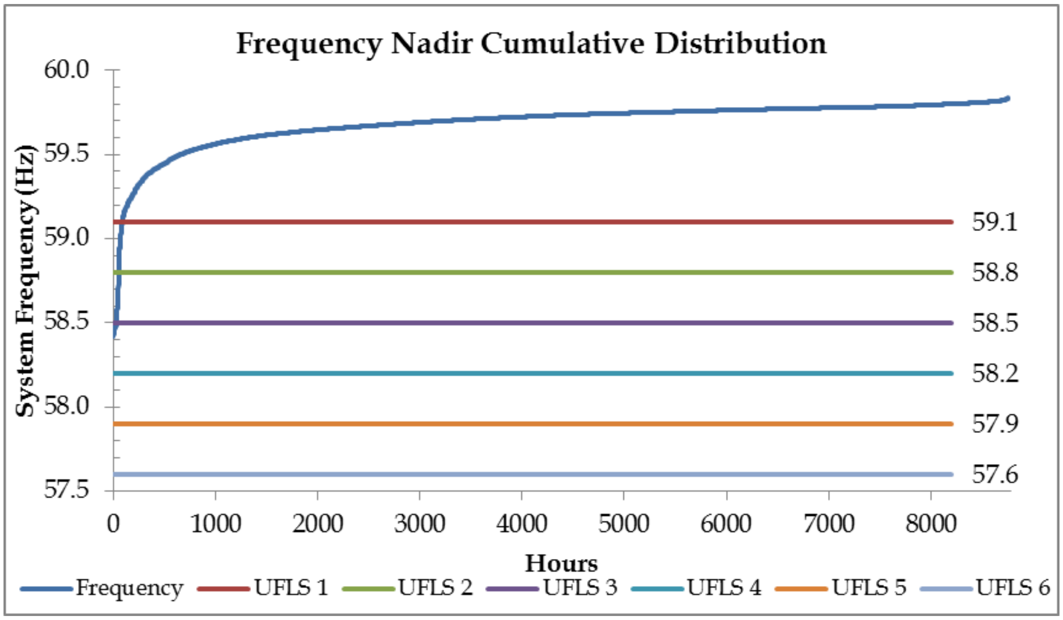

Figure O-389. Frequency Nadir Duration Curve 2019

Figure O-389 shows the frequency nadir duration curve for the Post April DR resource plan in 2019. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 35 hours of the year.

Unit	Unit Ratings					DR - HEP Trip Boundary Sun 9/15/19 Hour 1		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146	24.3	0.7	17.3
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	28.7	0.0	0.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	15.1	5.4	7.1
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30			
Apollo	20.5	0.0						
HRD	10.5	0.0				0.3		
Hydro	16.8	0				2		
Wind	91.0	0				0		
DG-PV	117.7	0						
Total Kinetic Energy							511	
Total Load							109	
Total Thermal Generation							106	
Total Renewable Generation							2	
Total Storage							0	
Total Generation							109	
Excess Generation							0	
Total Up Regulation							6	
Total Down Regulation							40	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-174. Unit Commitment and Dispatch 2019

Table O-174 shows the unit commitment and dispatch for the typical hour (9/15/19, 1:00 AM).

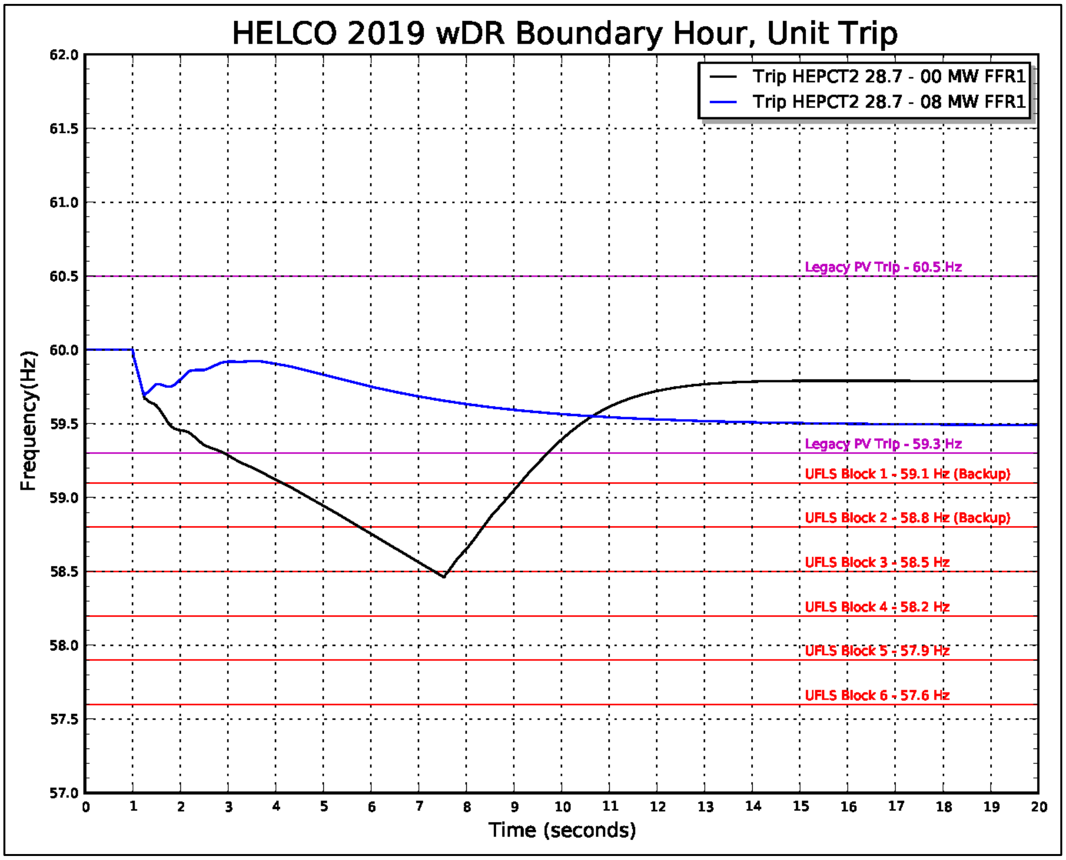

Figure O-390. Frequency Response Profile for FFR1 Boundary Hour

Figure O-390 shows the frequency response profile for a HEP CT2 trip at 28.7 MW. System kinetic energy is 511 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

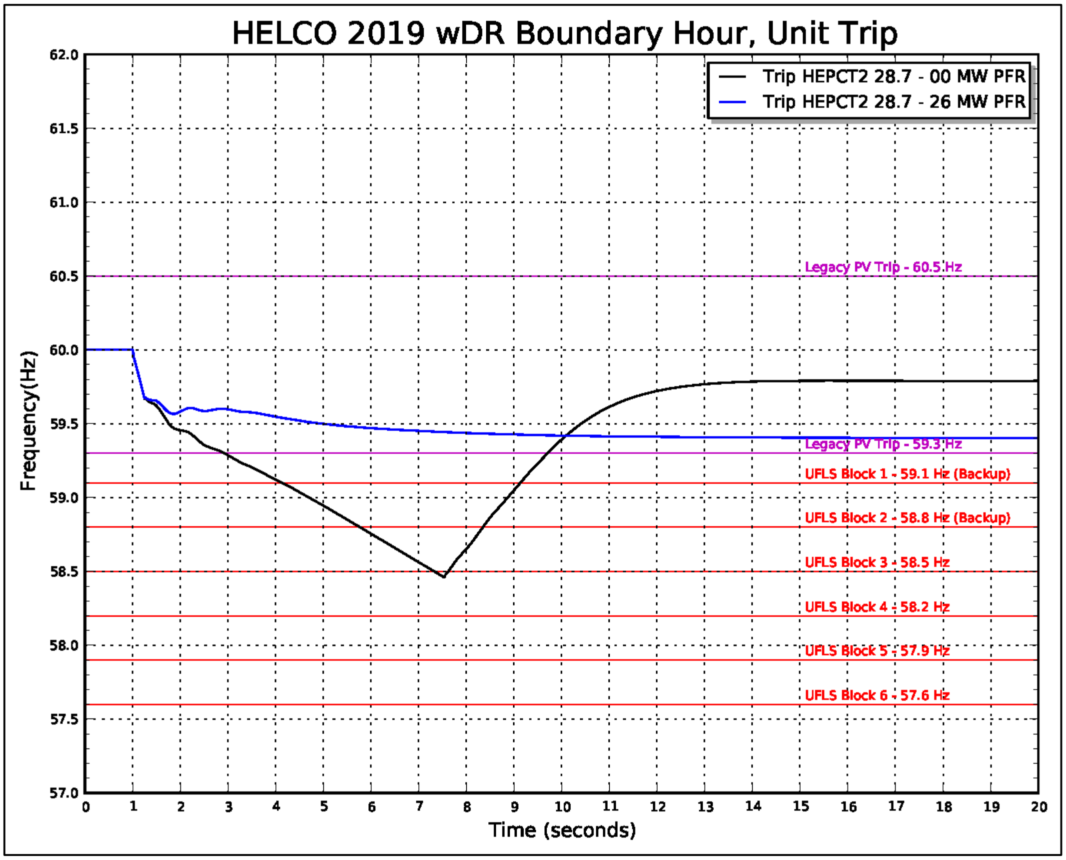

Figure O-391. Frequency Response Profile for PFR Boundary Hour

Figure O-391 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 26 MW. This is in addition to the 6 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					DR - Fault Sun 4/14/19 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53	7.0	13.0	0.0
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	15.8	12.7	6.8
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	5.0	8.5	0.0
Hill 6	20.5	8.0	2.53	27.5	70	13.3	7.2	5.3
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.8		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	0.6		
Apollo	20.5	0.0				20.5		
HRD	10.5	0.0				10.5		
Hydro	16.8	0				4		
Wind	91.0	0				31		
DG-PV	117.7	0				71		
Total Kinetic Energy							377	
Total Load							148	
Total Thermal Generation							41	
Total Renewable Generation							107	
Total Storage							0	
Total Generation							148	
Excess Generation							0	
Total Up Regulation							41	
Total Down Regulation							12	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.9
	60.5Hz Capacity			56.6		60.5Hz Output		35.0

Table O-175. Unit Commitment and Dispatch Fault Analysis

Table O-175 shows the unit commitment and dispatch for the 69 kV fault analysis (4/14/19, 1:00 PM).

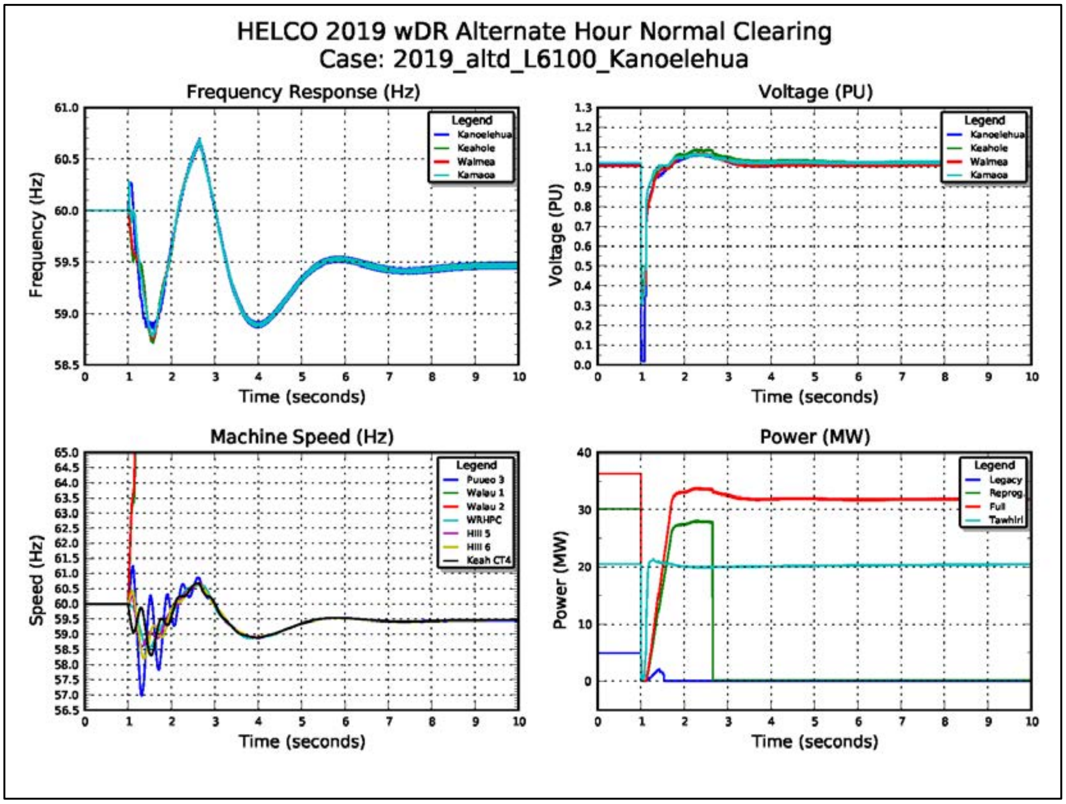

Figure O-392. System Performance Normally Cleared

Figure O-392 shows the system performance for a normally cleared fault on the on the L6100 circuit near the Kanoelehua Substation. Waiau Units 1 and 2 lose synchronism with the system almost immediately after the fault, indicating the normal clearing time exceeds the critical clearing time for stability.

Sensitivity analyses were performed with synchronous condensers and a BESS but the system remains unstable for normally cleared faults on multiple circuits with this unit commitment and dispatch schedule.

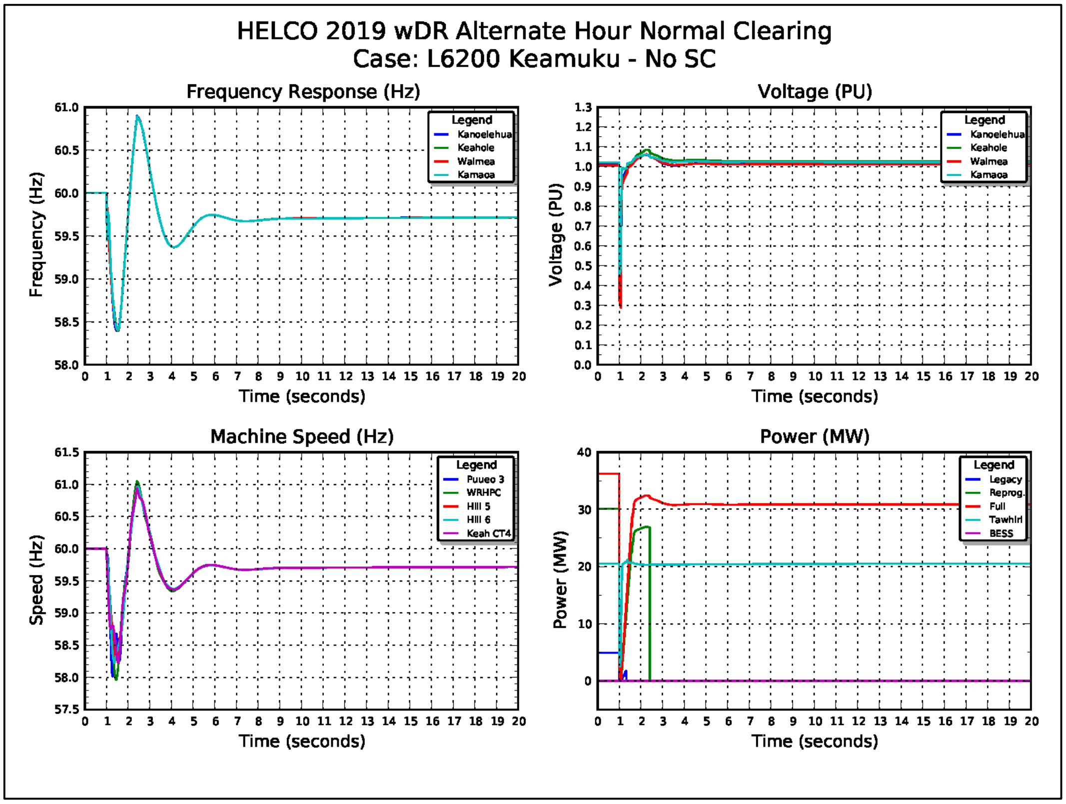

Figure O-393. System Performance Normally Cleared Fault

Figure O-393 shows the system performance for a normally cleared fault on the on the L6200 circuit near the Keamuku Substation. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 71 MW from the system. System frequency decays while system voltage recovers when the fault is cleared, restoring generation from some DG-PV. The aggregate frequency response from synchronous units, DG-PV restoration, as-available generation, and three blocks of UFLS is able to stabilize system frequency at 58.4 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to meet TPL-001 and/or improve the stability margin of the system. The analysis was performed for the L6200 circuit only.

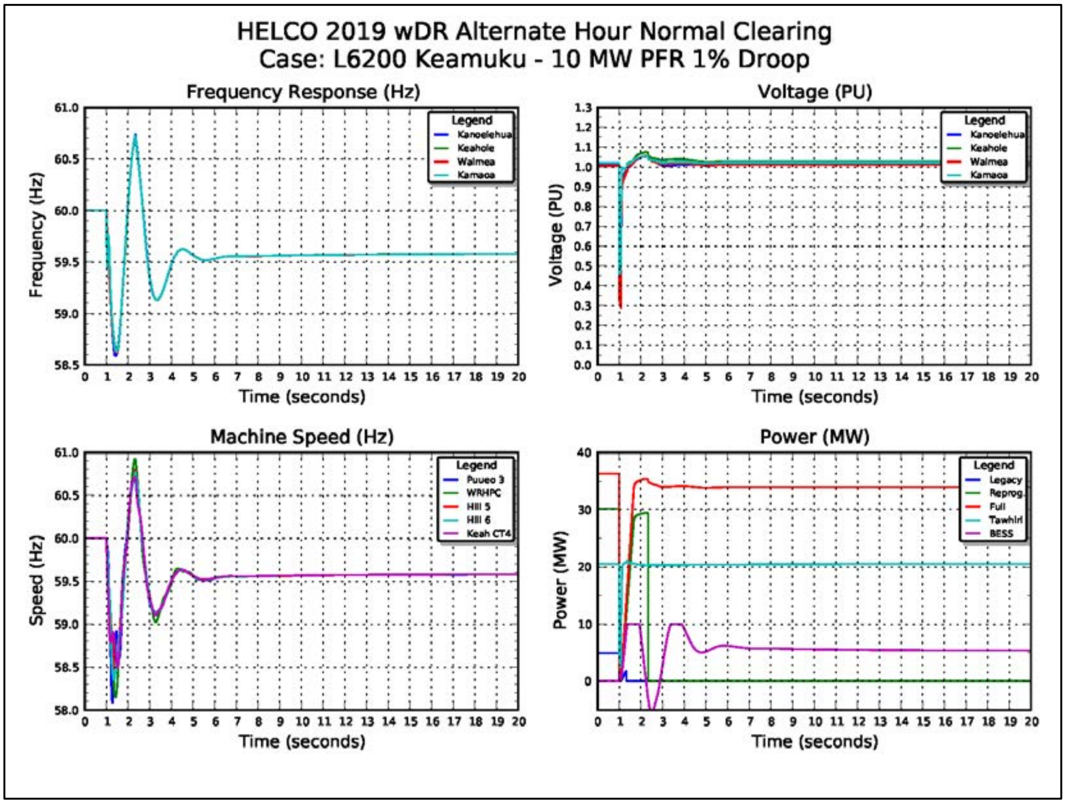

Figure O-394. Normally Cleared Fault Sensitivity 10 MW PFR

Figure O-394 shows system performance with the addition of 10 MW PFR at 1% droop response. For the purpose of this analysis, a 10 MW BESS was located at the Anaehoʻomalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, Tawhiri wind plant, and the 10 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2019 69kV Fault Normal Clearing Analysis				
Line No Outage	**3-phase Fault Near**	**System Status**	**Mitgation - Synchronous Condenser**	**Mitigaction - BESS**
L6100	Kanoelehua	Unstable	Unstable	Unstable
	Kaumana	Unstable	Unstable	Unstable
L6200	Kaumana	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L6300	Kilauea	Stable	Stable	Stable
	Puna	Stable	Stable	Stable
L6400	Kanoelehua	Unstable	Unstable	Unstable
	Puna	Unstable	Unstable	Unstable
L6500	Kaumana	Unstable	Stable	Unstable
	Pohoiki	Stable	Stable	Stable
L6600	Kamaoa	Stable	Stable	Stable
	Kilauea	Stable	Stable	Stable
L6700	Kahaluu	Stable	Stable	Stable
	Keahole	Stable	Stable	Stable
L6800	Keahole	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L7100	Anaehoomalu	Stable	Stable	Stable
	Poopoomino	Stable	Stable	Stable
L7200	Keamuku	Stable	Stable	Stable
	Waimea	Stable	Stable	Stable
L7300	Ouli	Stable	Stable	Stable
	Waimea	Stable	Stable	Stable
L7400	Pepeekeo	Unstable	Unstable	Unstable
	Wailuku	Unstable	Unstable	Unstable
L7500	Kailua	Stable	Stable	Stable
	Keahole	Stable	Stable	Stable
L7600	Honokaa	Stable	Stable	Stable
	Pepeekeo	Stable	Stable	Stable
L7700	Haina	Stable	Stable	Stable
	Waimea	Stable	Stable	Stable
L7800	Kanoelehua	Unstable	Unstable	Unstable
	Puueo	Unstable	Unstable	Unstable
L8100	Anaehoomalu	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L8200	Anaehoomalu	Stable	Stable	Stable
	Mauna Lani	Stable	Stable	Stable
L8300	Mauna Lani	Stable	Stable	Stable
	Ouli	Stable	Stable	Stable
L8400	Pepeekeo	Unstable	Unstable	Unstable
	Puueo	Unstable	Unstable	Unstable
L8500	Kaumana	Stable	Stable	Stable
	Keamuku	Stable	Stable	Stable
L8600	Kahaluu	Stable	Stable	Stable
	Kealia	Stable	Stable	Stable
L8700	Pohoiki	Stable	Stable	Stable
	Puna	Stable	Stable	Stable
L8800	Haina	Stable	Stable	Stable
	Honokaa	Stable	Stable	Stable
L9100	Keahole	Stable	Stable	Stable
	Poopoomino	Stable	Stable	Stable
L9200	Kaumana	Unstable	Unstable	Unstable
	Wailuku	Unstable	Unstable	Unstable
L9300	Kailua	Stable	Stable	Stable
	Keahole	Stable	Stable	Stable
L9500	Kahaluu	Stable	Stable	Stable
	Kailua	Stable	Stable	Stable
L9600	Kamaoa	Stable	Stable	Stable
	Kealia	Stable	Stable	Stable

Table O-176. Summary of Results Normal Clearing Fault Analysis

Table O-176 shows the results of the analysis for normally cleared faults. Thirteen simulations resulted in system instability because Waiau 1 loses synchronism with this unit commitment and dispatch schedule. Further analysis is required to determine if out-of-step protection is required.

The system requires 10 MW of PFR at 1% droop response to meet the requirements of TPL-001 for single contingency events. Further analysis is required to determine an optimal solution to improve system security.

2020

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai‘i, the critical busses with the highest MVAR demand are the Anaeho‘omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Dispatch Tue 2/25/20 Hour 20		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	58.0	2.0	39.5
Hill 5	13.5	5.0	2.20	15.6	34	9.7	3.8	4.7
Hill 6	20.5	8.0	2.53	27.5	70	16.3	4.2	8.3
Puna	15.5	6.0	4.63	18.8	87	11.3	4.2	5.3
Kano CT1	10.5	0.5	4.44	13.5	60			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	12.9	7.1	5.9
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	12.1		
Apollo	20.5	0.0				1.3		
HRD	10.5	0.0						
Hydro	16.8	0				14		
Wind	91.0	0				1		
DG-PV	122.2	0						
Total Kinetic Energy						715		
Total Load						161		
Total Thermal Generation						146		
Total Renewable Generation						15		
Total Storage						0		
Total Generation						161		
Excess Generation						0		
Total Up Regulation						21		
Total Down Regulation						80		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-177. Unit Commitment and Dispatch 2020 QV Analysis

Table O-177 shows the unit commitment and dispatch for the 2020 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR- QV MVAR Capability Tue 2/25/20 Hour 20		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	29.8	-19.3	-2.6	32.3	-16.7
Keahole STCC	27.9	-19.4			
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	48.0	-28.1	-3.5	51.6	-24.6
Hill 5	9.8	-7.9	-1.6	11.4	-6.3
Hill 6	15.1	-12.7	-2.8	17.9	-9.9
Puna	11.4	-8.2	1.9	9.5	-10.1
Kano CT1	7.1	0.0			
Keah CT2	15.0	-11.5			
Puna CT3	17.1	-11.8	3.0	14.1	-14.8
Diesels (x9)	20.3	-12.3			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2	-0.7	5.9	-9.4
HRD	4.0	-4.0	0.3	3.7	-4.3
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			-5.6		
Total Renewable MVAR Generation			-0.5		
Total Cap Bank MVAR			67.9		
Charging MVAR			16.2		
Total MVAR Supply			78.0		
Total MVAR Load			38.8		
Total MVAR Losses			39.2		
Excess MVAR Generation			0.0		
Total MVAR Supply Capability				146	
Total MVAR Absorb Capability					-96.2

Table O-178. MVAR Capability 2020 QV Analysis

Table O-178 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
36	L7700 Haina

Table O-179. N-1 Contingencies 2020 QV Analysis

Table O-179 shows the N-1 contingency that has the greatest impact to MVAR requirements for the critical busses.

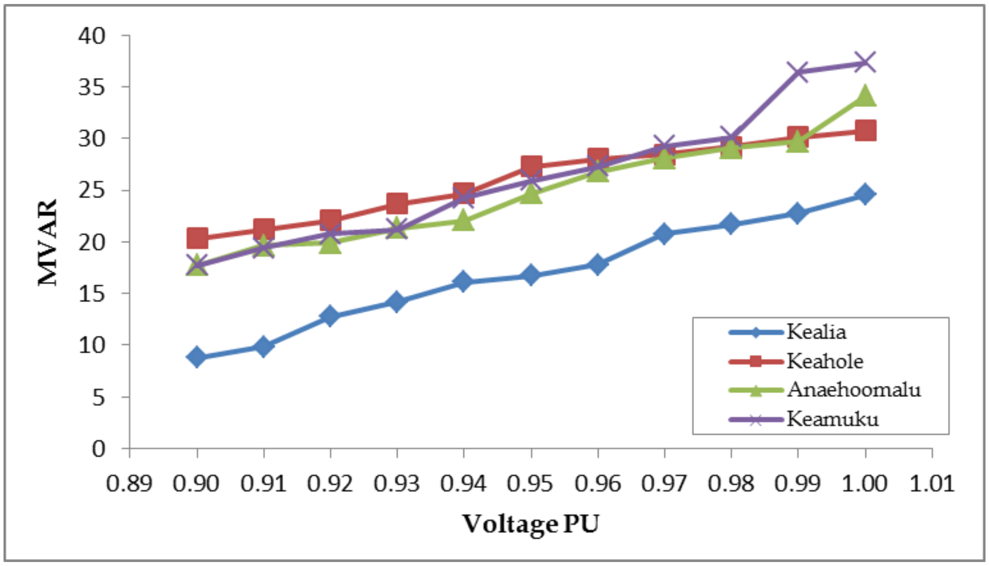

Figure O-395. QV Curves

Figure O-395 shows the QV curves for the Anaeho'omalu, Keahole, Kealia, and Keamuku busses for the worst-case N-1 contingency event. All critical busses require additional reactive power with the highest demand from the Keahole bus at 27 MVAR. The system has 146 MVAR of reserve capacity but all of these resources are on the east side of the island, far away from the load center.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	25	36	23	36	22	36	21	36	18	36	17	36	16	36	14	36	13	36	10	36	9
8400	Keahole	36	31	36	30	36	29	36	28	36	28	36	27	36	25	36	24	36	22	36	21	36	20
8500	Anaehoomalu	36	34	36	30	36	29	36	28	36	27	36	25	36	22	36	21	36	20	36	20	36	18
8700	Keamuku	36	37	36	36	36	30	36	29	36	27	36	26	36	24	36	21	36	21	36	19	36	18

Table O-180. Results 2019 QV Analysis

Table O-180 shows the summary of results for the 2020 QV analysis.

To mitigate the reactive power shortfall, 18.8 MVA synchronous condensers were added to the Keahole and Keamuku switching stations.

Con #	Contingency Description
23	L7100 Anaehoomalu-Poopoomino
36	L7700 Haina
50	L8600 Kahaluu

Table O-181. N-1 Contingencies 2020 QV Mitigation Analysis

Table O-181 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

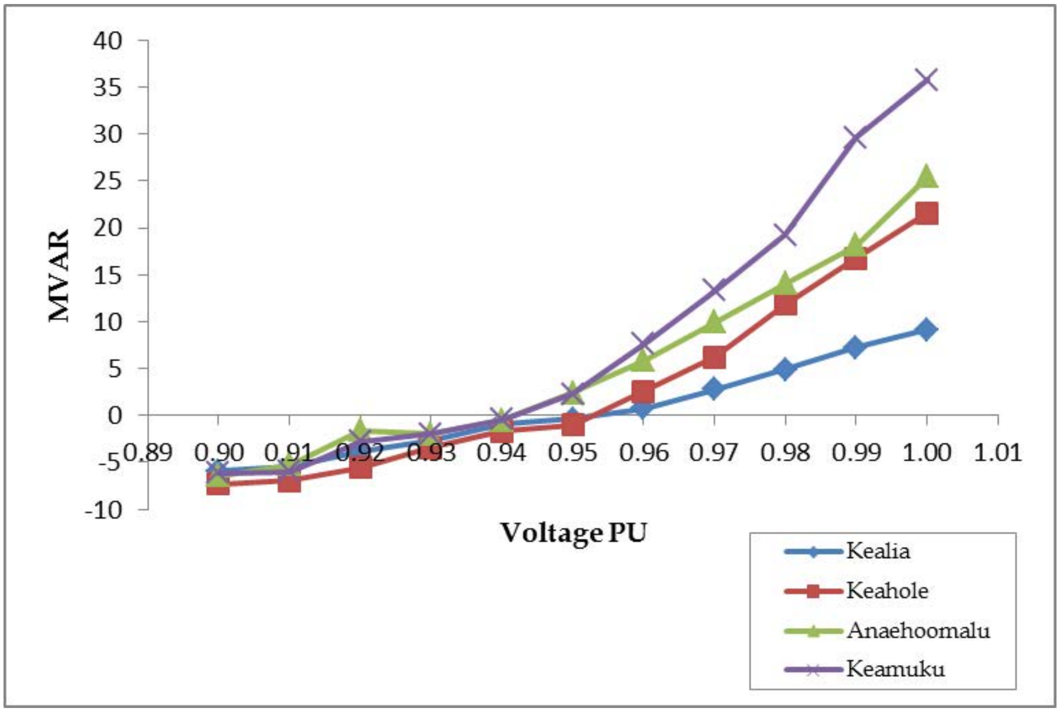

Figure O-396. QV Curves Synchronous Condensers

Figure O-396 shows the QV curves with 18.8 MVA synchronous condensers at Keahole and Keamuku switching stations.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	9	36	7	36	5	36	3	36	1	50	0	50	-1	50	-3	50	-4	50	-5	50	-6
8400	Keahole	36	22	36	17	36	12	36	6	36	3	36	-1	36	-2	36	-3	36	-6	36	-7	36	-7
8500	Anaehoomalu	36	25	36	18	36	14	36	10	36	6	36	2	36	0	36	-2	36	-2	36	-5	36	-6
8700	Keamuku	36	36	36	30	36	19	36	13	36	8	36	2	36	0	36	-2	36	-3	36	-6	36	-6

Table O-182. Summary of Results 2020 QV Mitigation Analysis

Table O-182 shows the results of the QV analysis with the additional synchronous condensers. The Anaeho'omalu and Keamuku busses require 2 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met.

Under this contingency, L6200 is operating at 113% of its emergency rating which violates the transmission planning criteria. To mitigate the overload, the conductors for L6200 were increased from 336 AAC to 556 AAC to simulate a re-conductor project.

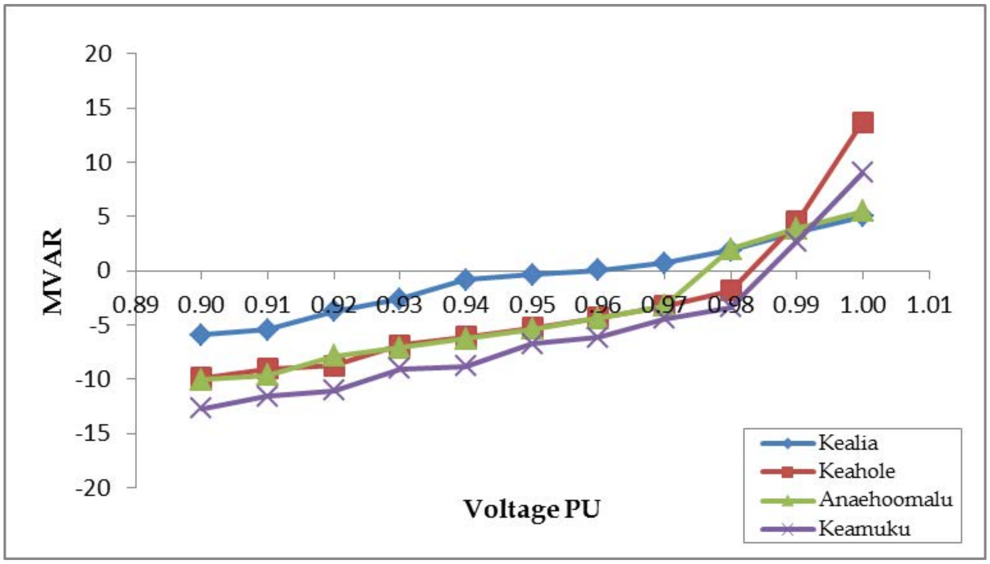

Figure O-397. QV Curves L6200 Reconductor

Figure O-397 shows the QV curves with the L6200 conductors increased from 336 AAC to 556 AAC.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	50	5	50	4	50	2	50	1	50	0	50	0	50	-1	50	-3	50	-4	50	-5	50	-6
8400	Keahole	36	14	23	5	23	-2	23	-3	36	-4	36	-5	36	-6	36	-7	36	-9	36	-9	36	-10
8500	Anaehoomalu	36	5	36	4	36	2	36	-3	36	-4	36	-5	36	-6	36	-7	36	-8	36	-10	36	-10
8700	Keamuku	36	9	36	3	36	-3	36	-4	36	-6	36	-7	36	-9	36	-9	36	-11	36	-12	36	-13

Table O-183. Summary of Results 2020 QV Analysis L6200 Reconductor

Table O-183 shows the results for the QV analysis with the L6200 conductors increased from 336 AAC to 556 AAC. Increasing the ampacity of L6200 eliminates the overload condition and meets the reactive power requirements of the system. No additional synchronous condensers are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

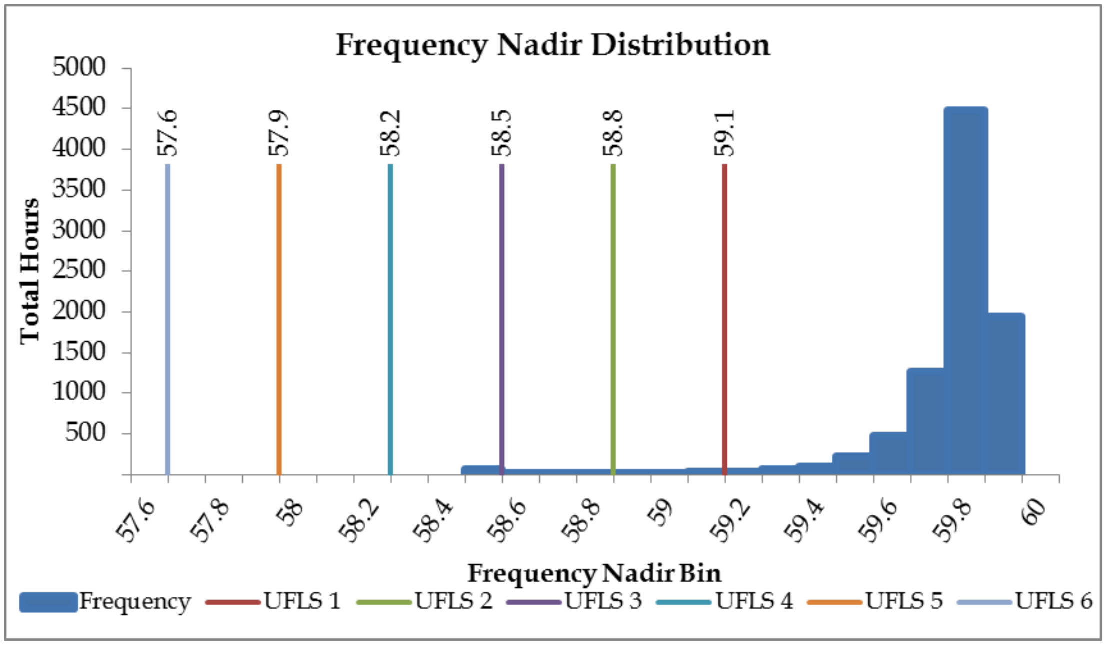

Figure O-398. Frequency Nadir Histogram 2020

Figure O-398 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 71 hours was 3:00 AM on Tuesday, November 10. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

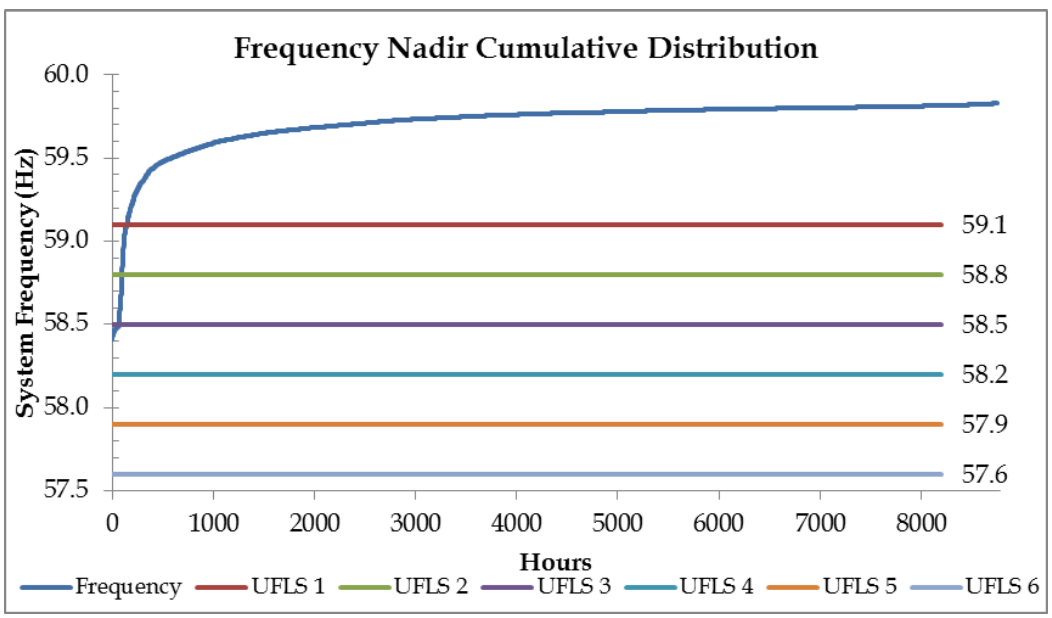

Figure O-399. Frequency Nadir Duration Curve 2020

Figure O-399 shows the frequency nadir duration curve for the Post April DR resource plan in 2020. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 71 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Tue 11/10/20 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	28.7	0.0	0.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	15.0	5.5	7.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2	2.5	0.0	1.7
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.8		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	7.1		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				10		
Wind	91.0	0				0		
DG-PV	122.2	0						
Total Kinetic Energy							466	
Total Load							94	
Total Thermal Generation							84	
Total Renewable Generation							10	
Total Storage							0	
Total Generation							94	
Excess Generation							0	
Total Up Regulation							6	
Total Down Regulation							25	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-184. Unit Commitment and Dispatch 2020

Table O-184 shows the unit commitment and dispatch for the typical hour (11/10/20, 3:00 AM).

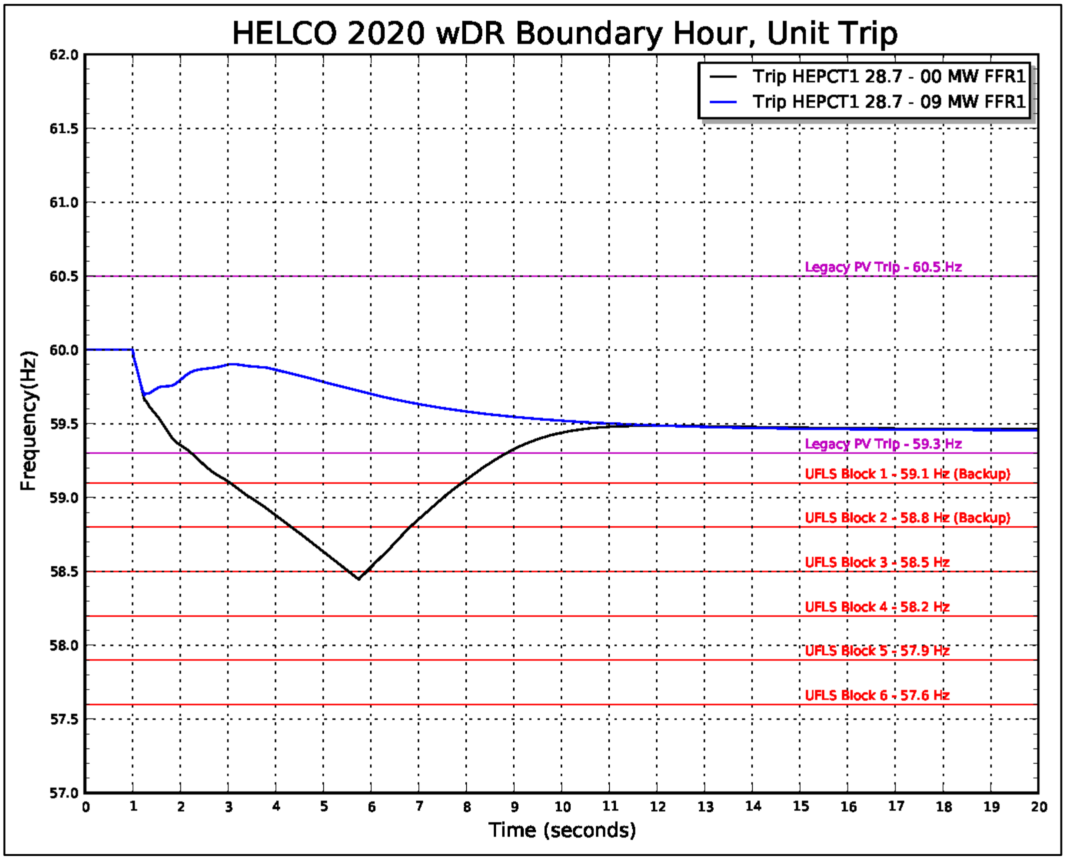

Figure O-400. Frequency Response Profile for FFR1 Boundary Hour

Figure O-400 shows the frequency response profile for a HEP CT2 trip at 28.7 MW. System kinetic energy is 466 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 9 MW.

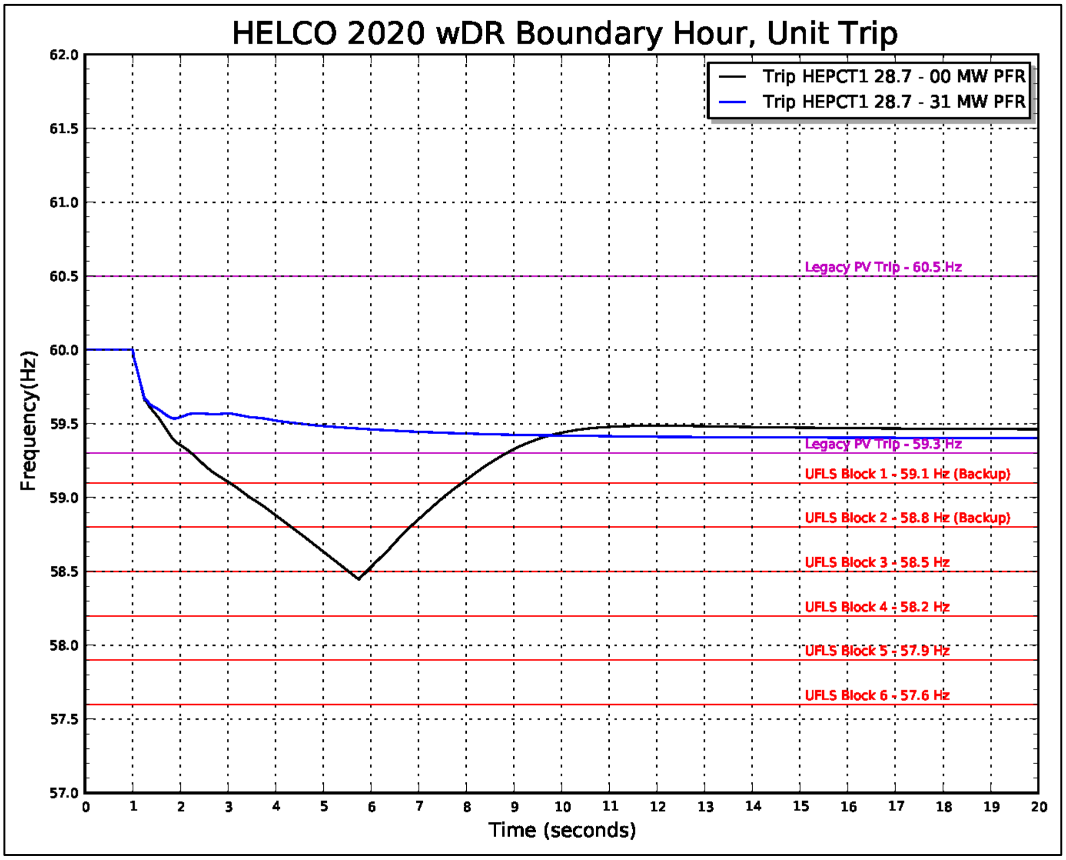

Figure O-401. Frequency Response Profile for PFR Typical Hour

Figure O-401shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 31 MW. This is in addition to the 6 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					DR - Fault Thu 2/27/20 Hour 14		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	20.0	40.0	1.5
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	8.0	12.5	0.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	10.3		
Apollo	20.5	0.0				19.6		
HRD	10.5	0.0				7.1		
Wind1	20.0	0.0				17.6		
Hydro	16.8	0				12		
Wind	91.0	0				44		
DG-PV	122.2	0				73		
Total Kinetic Energy							342	
Total Load							158	
Total Thermal Generation							28	
Total Renewable Generation							130	
Total Storage							0	
Total Generation							158	
Excess Generation							0	
Total Up Regulation							52	
Total Down Regulation							2	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.8
	60.5Hz Capacity			56.6		60.5Hz Output		34.4

Table O-185. Unit Commitment and Dispatch Fault Analysis

Table O-185 shows the unit commitment and dispatch for the 69 kV fault analysis (2/27/20, 2:00 PM).

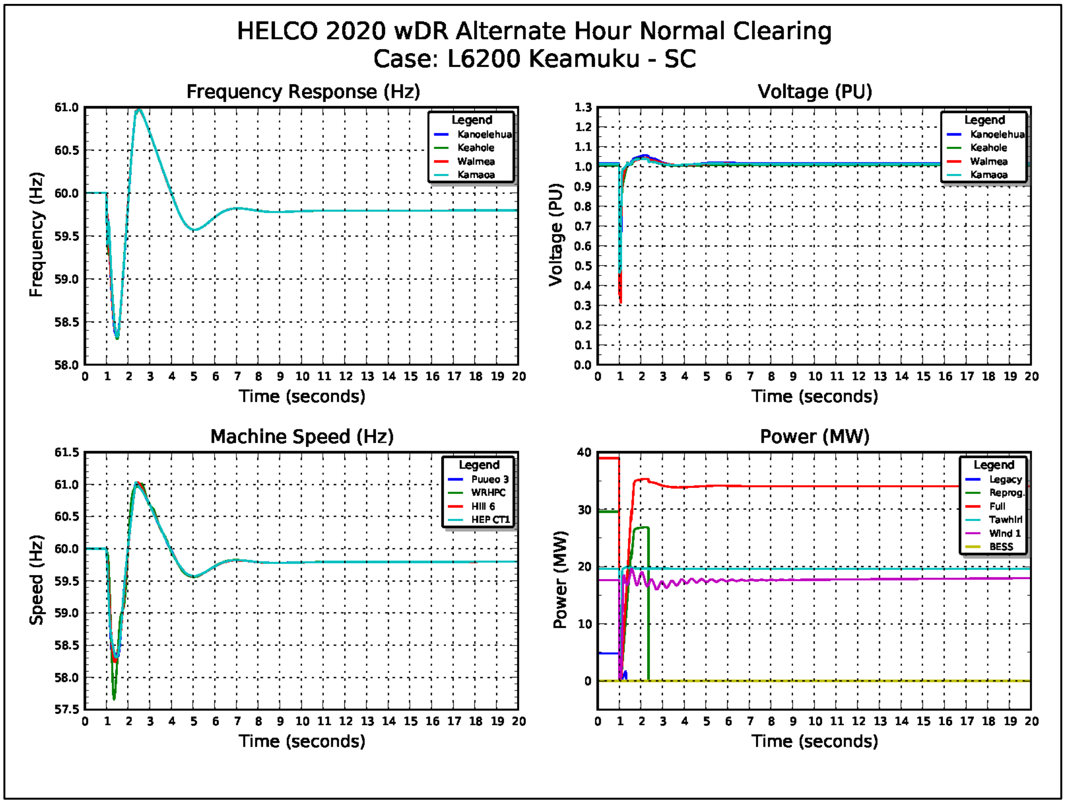

Figure O-402. System Performance Normally Cleared Fault

Figure O-402 shows the system performance for a normally cleared fault on the L6200 circuit near the Keamuku Substation. System voltage is suppressed below the 0.5 PU voltage ride-through threshold for inverter-based generation. The inverters remain connected to the system but output current drops to zero, essentially tripping 71 MW from the system. System frequency decays while system voltage recovers when the fault is cleared, restoring generation from some DG-PV. The aggregate frequency response from synchronous units, DG-PV restoration, as-available generation, and three blocks of UFLS is able to stabilize system frequency at 58.4 Hz but eventually the response over-compensates and drives the frequency apex above 60.5 Hz, tripping legacy PV.

Simulations of normally cleared faults were stable for all transmission circuits but multiple blocks of UFLS were required to stabilize system security. Non-exhaustive sensitivity analyses were performed to identify potential mitigating strategies to improve system security. Results will vary for different circuits and dispatch schedules.

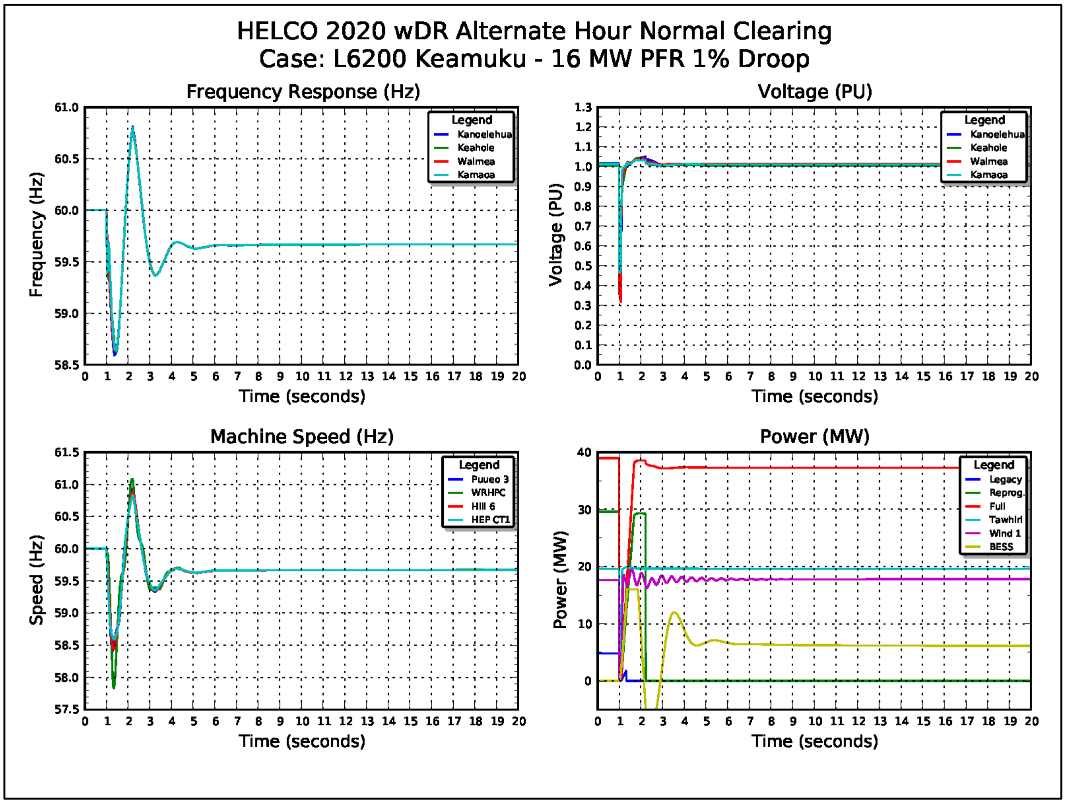

Figure O-403. Normally Cleared Fault Sensitivity 16 MW PFR

Figure O-403 shows system performance with the addition of 16 MW PFR at 1% droop response. For the purpose of this analysis, a 16 MW BESS was located at the Anaeho'omalu Substation.

The plot at the bottom right shows the frequency response from DG-PV, Tawhiri wind plant, and the 10 MW BESS. The aggregate response from synchronous units, PFR, the restoration of DG-PV generation, and two blocks of UFLS brings the system into compliance with TPL-001.

2021

QV Analysis

Analysis was performed to determine if resource plans meet the reactive power requirements of the system for N-1 contingency events. For Hawai'i, the critical busses with the highest MVAR demand are the Anaeho'omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

Unit	Unit Ratings					DR - QV Dispatch Mon 11/8/21 Hour 16		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168	58.0	2.0	39.5
Hill 5	13.5	5.0	2.20	15.6	34	9.1	4.4	4.1
Hill 6	20.5	8.0	2.53	27.5	70	16.0	4.5	8.0
Puna	15.5	6.0	4.63	18.8	87	11.3	4.2	5.3
Kano CT1	10.5	0.5	4.44	13.5	60			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147	14.1	5.9	7.1
Diesels (x9)	2.5	0.8	0.70	3.4	2			
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.8		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	11.2		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				14		
Wind	91.0	0				0		
DG-PV	126.0	0				18		
Total Kinetic Energy						715		
Total Load						178		
Total Thermal Generation						146		
Total Renewable Generation						32		
Total Storage						0		
Total Generation						178		
Excess Generation						0		
Total Up Regulation						21		
Total Down Regulation						80		
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		1.2
	60.5Hz Capacity			56.6		60.5Hz Output		8.2

Table O-186. Unit Commitment and Dispatch 2021 QV Analysis

Table O-186 shows the unit commitment and dispatch for the 2021 QV analysis. Reactive power requirements increase with system load.

Unit	Unit Ratings		DR - QV MVAR Capability Mon 11/8/21 Hour 16		
	Qmax	Qmin	Qgen	Supply Cpblty	Absorb Cpblty
PGV	29.8	-19.3	-6.1	35.8	-13.3
Keahole STCC	27.9	-19.4			
Keahole DTCC	42.2	-30.0			
Keahole CT4	14.3	-10.6			
Keahole CT5	18.7	-13.6			
HEP STCC	30.8	-16.9			
HEP DTCC	48.0	-28.1	-0.3	48.3	-27.8
Hill 5	10.0	-8.2	4.6	5.4	-12.8
Hill 6	15.3	-12.8	8.0	7.2	-20.9
Puna	11.4	-8.2	-0.4	11.8	-7.8
Kano CT1	7.1	0.0			
Keah CT2	15.0	-11.5			
Puna CT3	16.8	-11.6	-0.6	17.5	-11.0
Diesels (x9)	20.3	-12.3			
HELCO Hydro	0.0	0.0			
Wailuku Hydro	0.0	0.0			
Apollo	5.1	-10.2			
HRD	4.0	-4.0	3.0	1.0	-7.0
Wind1	6.6	-6.6			
Hydro					
Wind					
DG-PV					
Total Thermal MVAR Generation			5.3		
Total Renewable MVAR Generation			3.0		
Total Cap Bank MVAR			62.2		
Charging MVAR			16.2		
Total MVAR Supply			86.6		
Total MVAR Load			49.5		
Total MVAR Losses			38.2		
Excess MVAR Generation			-1.0		
Total MVAR Supply Capability				127	
Total MVAR Absorb Capability					-100.5

Table O-187. MVAR Capability 2021 QV Analysis

Table O-187 shows the reactive power demand and reserve capacity for this unit commitment schedule and dispatch.

Con #	Contingency Description
35	L7700 Haina-Waimea
36	L7700 Haina
37	L7700 Waimea

Table O-188. N-1 Contingencies 2021 QV Analysis

Table O-188 shows the N-1 contingencies that were simulated in the QV analysis. These contingencies have the greatest impact to MVAR requirements for the critical busses.

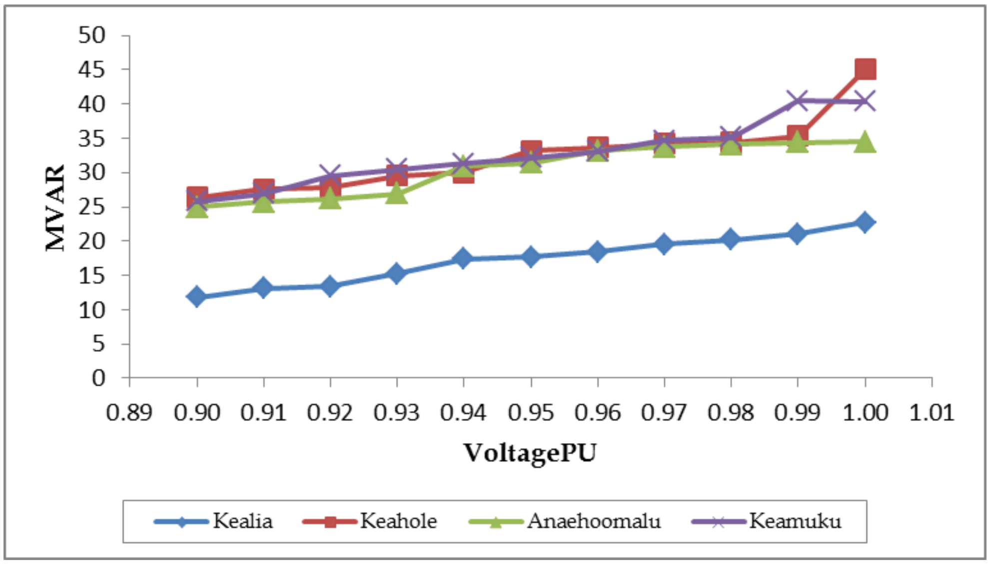

Figure O-404. QV Curves 2021

Figure O-404 shows the QV curves for the Anaehoʻomalu, Keahole, Kealia, and Keamuku busses for the N-1 contingency events. All critical busses require additional reactive power with the highest demand from the Keahole bus at 33 MVAR. The system has 127 MVAR of reserve capacity but all of these resources are on the east side of the island, far away from the load center.

Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
37	23	37	21	35	20	35	20	35	18	37	18	35	17	35	15	37	13	37	13	35	12
36	45	36	35	36	34	36	34	36	34	36	33	36	30	36	29	36	28	36	28	36	26
36	35	36	34	36	34	36	34	36	33	36	31	36	31	36	27	36	26	36	26	36	25
36	40	36	40	36	35	36	35	36	33	36	32	36	31	36	30	36	30	36	27	36	26

Table O-189. Summary of Results 2021 QV Analysis

Table O-189 shows the summary of results for the 2021 QV analysis.

To mitigate the reactive power shortfall, a 18.8 MVA synchronous condenser was added to Keahole and two synchronous condensers were added to Keaumuku (15.6 MVA and 18.8 MVA).

Con #	Contingency Description
36	L7700 Haina
50	L8600 Kahaluu

Table O-190. N-1 Contingencies 2021 QV Analysis

Table O-190 shows the N-1 contingencies that have the greatest impact to MVAR requirements for the critical busses.

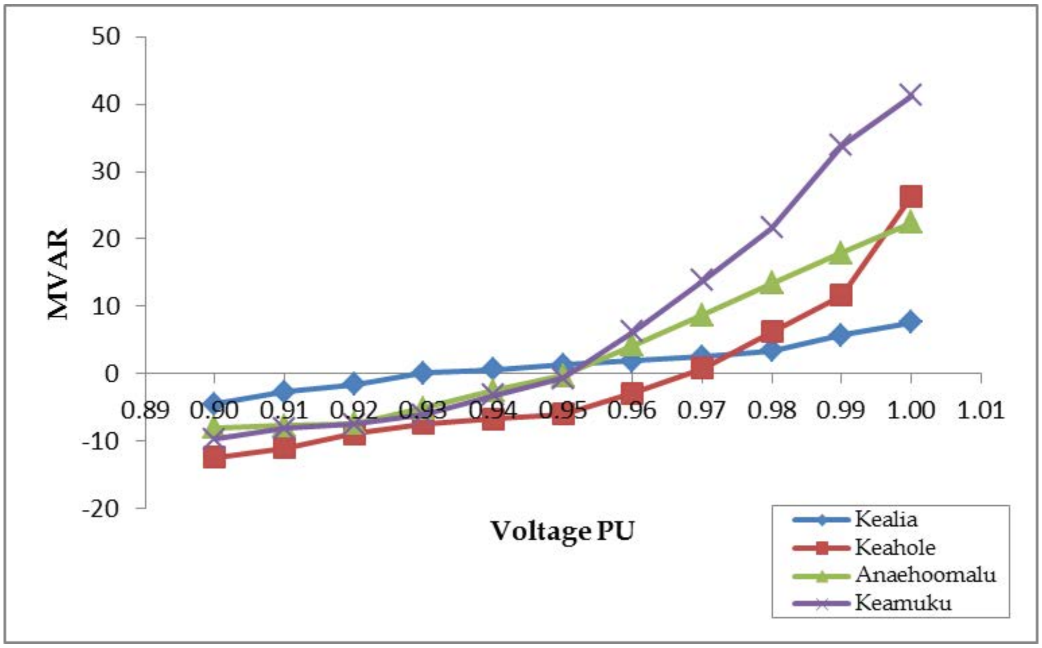

Figure O-405. QV Curves 2021

Figure O-405 shows the QV curves for the Anaeho'omalu, Keahole, Kealia, and Keamuku busses with the three synchronous condensers added to the system.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	8	36	6	36	3	50	3	50	2	50	1	50	1	50	0	50	-2	50	-3	50	-4
8400	Keahole	36	26	36	12	36	6	36	1	36	-3	36	-6	36	-7	36	-7	36	-9	36	-11	36	-12
8500	Anaehoomalu	36	22	36	18	36	13	36	9	36	4	36	0	36	-3	36	-5	36	-7	36	-8	36	-8
8700	Keamuku	36	41	36	34	36	22	36	14	36	6	36	-1	36	-3	36	-6	36	-7	36	-8	36	-10

Table O-191. Summary of Results 2021 QV Analysis Synchronous Condensers

Table O-191 shows the results of the QV analysis with the additional synchronous condensers. The Kealia bus requires 1 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met.

Under this contingency, line L6200 is operating at 113% of its emergency rating which violates the transmission planning criteria. To mitigate the overload, the conductors for L6200 were increased from 336 AAC to 556 AAC to simulate a re-conductor project.

Con #	Contingency Description
36	L7700 Haina

Table O-192. N-1 Contingency 2021 QV Analysis

Table O-192 shows the N-1 contingency that has the greatest impact to MVAR requirements for the critical busses.

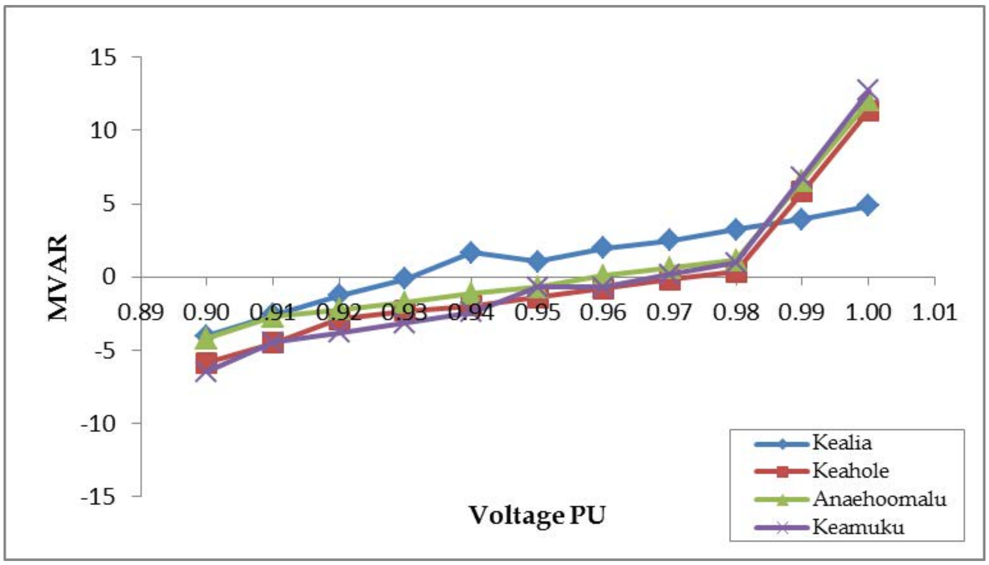

Figure O-406. QV Curves L6200 Reconductored

Figure O-406 shows the QV curves with the L6200 conductors increased from 336 AAC to 556 AAC.

Bus Num	Name	Minimum Reactive Requirement to maintain bus voltage under N-1 conditions																					
		1.00		0.99		0.98		0.97		0.96		0.95		0.94		0.93		0.92		0.91		0.90	
		Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR	Con #	MVAR
8100	Kealia	36	5	36	4	36	3	36	3	36	2	36	1	36	2	36	0	36	-1	36	-3	36	-4
8400	Keahole	36	11	36	6	36	0	36	0	36	-1	36	-1	36	-2	36	-2	36	-3	36	-4	36	-6
8500	Anaehoomalu	36	12	36	7	36	1	36	1	36	0	36	-1	36	-1	36	-2	36	-2	36	-3	36	-4
8700	Keamuku	36	13	36	7	36	1	36	0	36	-1	36	-1	36	-2	36	-3	36	-4	36	-4	36	-6

Table O-193. Summary of Results 2021 QV Analysis Synchronous Condensers

Table O-193 shows the results for the QV analysis with the L6200 conductors increased from 336 AAC to 556 AAC. The Kealia bus requires 1 MVAR but for the purpose of this analysis, the reactive power requirements of the system are met. Increasing the ampacity of L6200 eliminates the overload condition and also meets the reactive power requirements of the system. No additional synchronous condensers are required.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

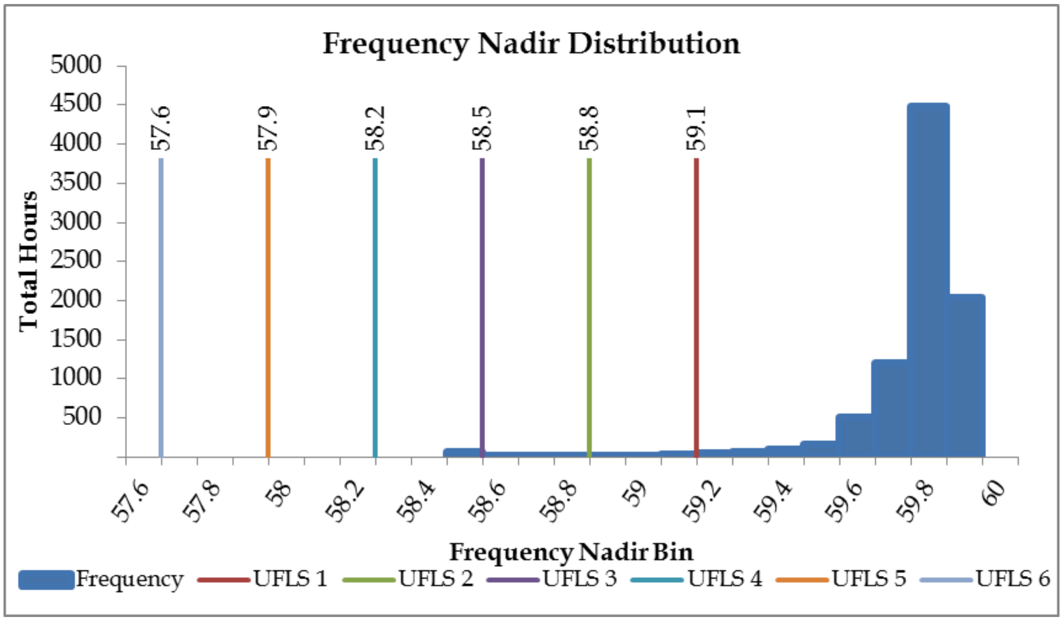

Figure O-407. Frequency Nadir Histogram 2020

Figure O-407 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 61 hours was 1:00 AM on Tuesday, January 19. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

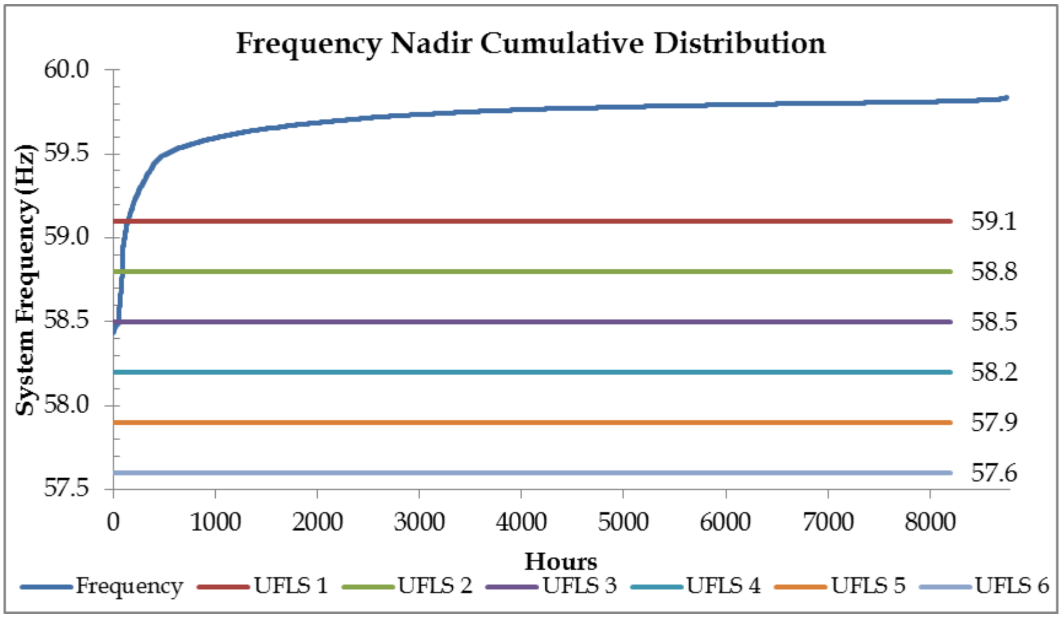

Figure O-408. Frequency Nadir Duration Curve 2021

Figure O-408 shows the frequency nadir duration curve for the Post April DR resource plan in 2021. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 61 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Tue 1/19/21 Hour 1		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53	17.3	2.7	10.3
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	28.7	0.0	0.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70	17.3	3.2	9.3
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.5		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				4		
Wind	91.0	0				0		
DG-PV	126.0	0						
Total Kinetic Energy							517	
Total Load							105	
Total Thermal Generation							101	
Total Renewable Generation							4	
Total Storage							0	
Total Generation							105	
Excess Generation							0	
Total Up Regulation							6	
Total Down Regulation							36	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-194. Unit Commitment and Dispatch 2021

Table O-194 shows the unit commitment and dispatch for the typical hour (1/19/21, 1:00 AM).

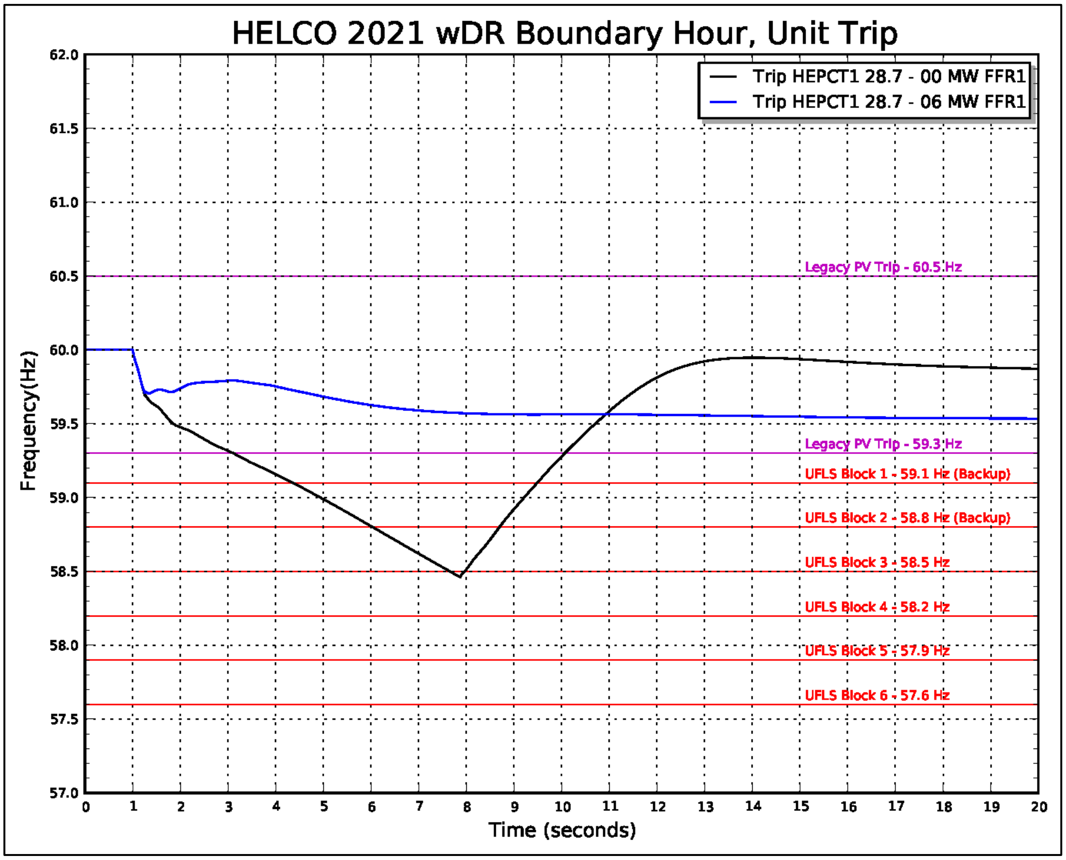

Figure O-409. Frequency Response Profile for FFR1 Boundary Hour

Figure O-409 shows the frequency response profile for a HEP CT1 trip at 28.7 MW. System kinetic energy is 517 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 6 MW.

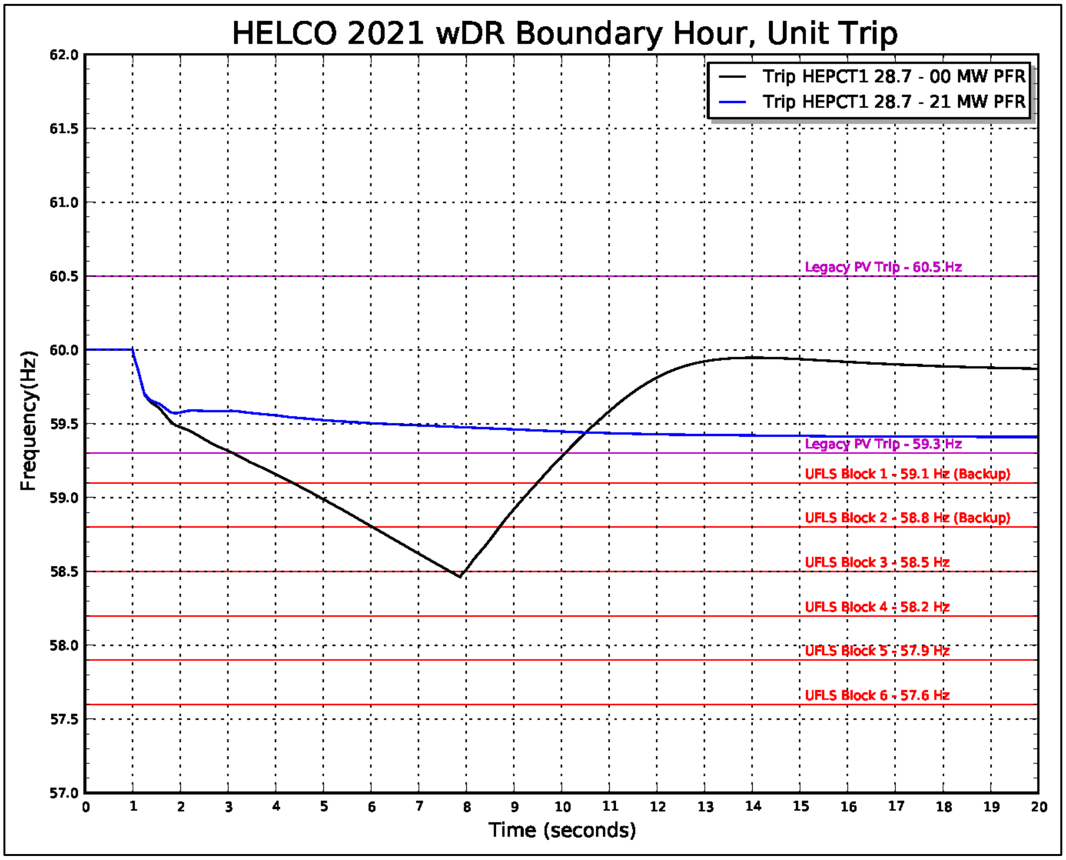

Figure O-410. Frequency Response Profile for PFR Boundary Hour

Figure O-410 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 21 MW. This is in addition to the 6 MW of upward regulation from thermal generation.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system. An electrical fault is the most severe disturbance on a transmission system that is typically characterized by high system frequency and low voltages. An electrical fault can suppress system voltage below the 0.5 PU voltage ride-through threshold of inverter-based generation. If system voltage does not recover within the 0.5 second ride-through time, inverters will disconnect from the system.

Unit	Unit Ratings					DR - Fault Sat 8/14/21 Hour 13		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174			
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199	18.9	35.1	11.9
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116			
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34	5.0	8.5	0.0
Hill 6	20.5	8.0	2.53	27.5	70	8.0	12.5	0.0
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	3.1		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	9.6		
Apollo	20.5	0.0				19.6		
HRD	10.5	0.0				10.5		
Wind1	20.0	0.0				18.0		
Hydro	16.8	0				13		
Wind	91.0	0				48		
DG-PV	126.0	0				71		
Total Kinetic Energy							407	
Total Load							164	
Total Thermal Generation							32	
Total Renewable Generation							132	
Total Storage							0	
Total Generation							164	
Excess Generation							0	
Total Up Regulation							56	
Total Down Regulation							12	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		4.7
	60.5Hz Capacity			56.6		60.5Hz Output		33.2

Table O-195. Unit Commitment and Dispatch Fault Analysis

Table O-195 shows the unit commitment and dispatch for the 69 kV fault analysis (8/14/21, 1:00 PM).

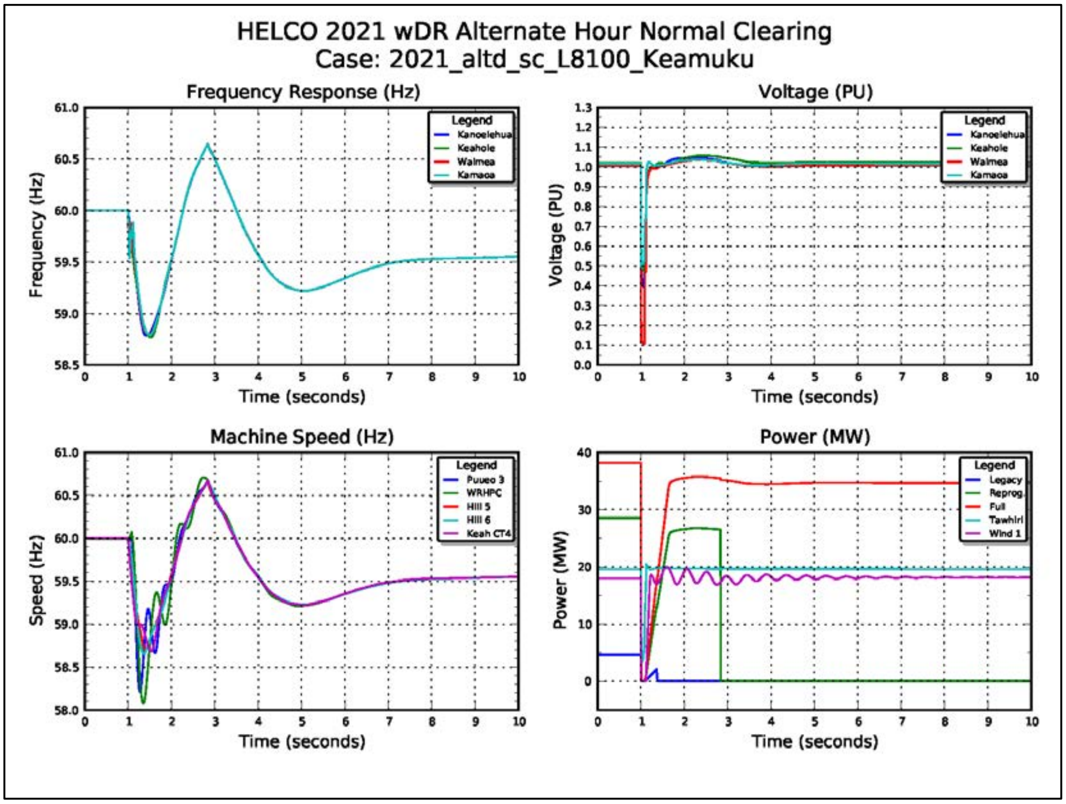

Figure O-411. System Performance Normally Cleared Fault

Figure O-411 shows the system performance for a normally cleared fault on the on the L8100 circuit near the Keamuku Substation. The frequency nadir is 58.7 Hz which is in compliance with TPL-001. Simulations of normally cleared faults were stable for all transmission circuits and in compliance with TPL-001. Improved system performance can be attributed to the commitment of Keahole in DTCC operation.

2025

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

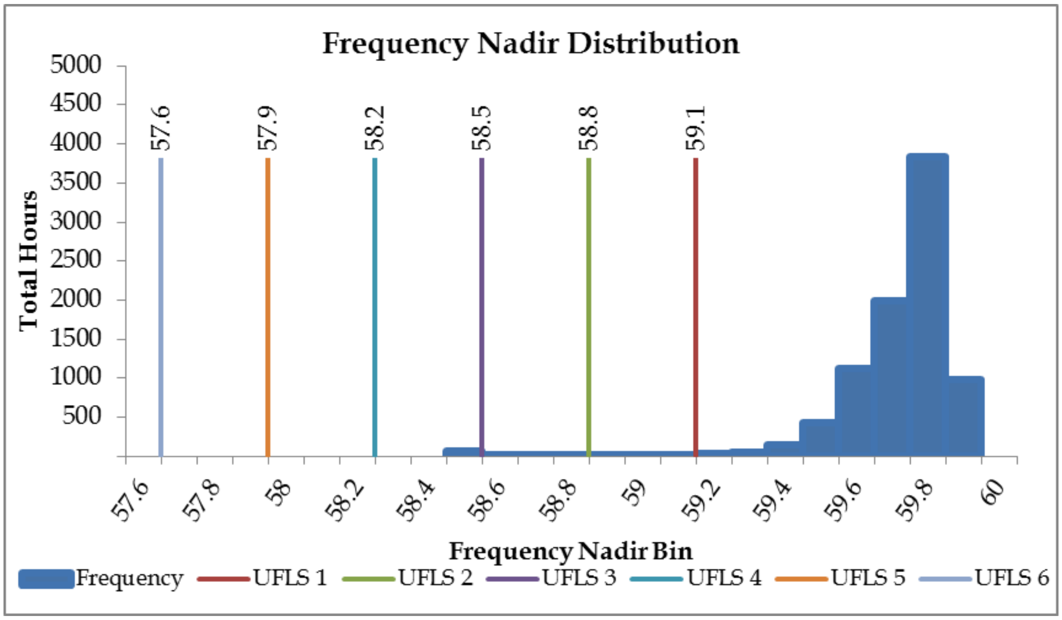

Figure O-412. Frequency Nadir Histogram 2025

Figure O-412 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 71 hours was 3:00 AM on Wednesday, February 26. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

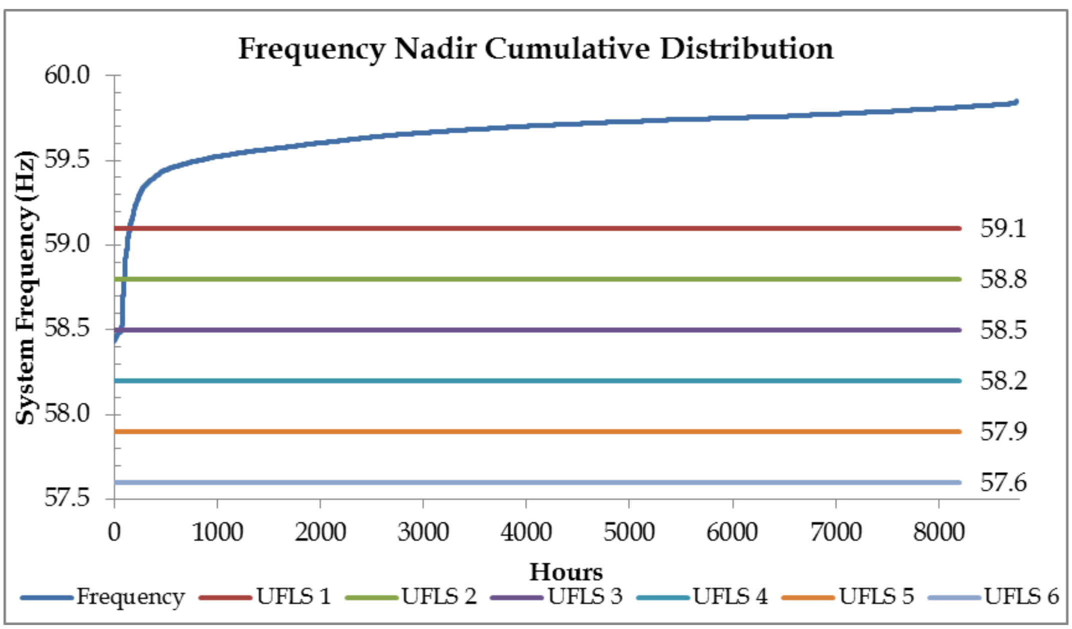

Figure O-413. Frequency Nadir Duration Curve 2025

Figure O-413 shows the frequency nadir duration curve for the Post April DR resource plan in 2025. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 71 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Wed 2/26/25 Hour 3		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.5	5.0	14.5
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Geo1	20.0		5.00	40.0	200	20.0	0.0	
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	1.6		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	12.1		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Hydro	16.8	0				14		
Wind	91.0	0				0		
DG-PV	136.4	0						
Total Kinetic Energy						594		
Total Load						95		
Total Thermal Generation						82		
Total Renewable Generation						14		
Total Storage						0		
Total Generation						95		
Excess Generation						0		
Total Up Regulation						5		
Total Down Regulation						31		
Legacy DG-PV	59.3Hz Capacity		7.9			59.3Hz Output		0.0
	60.5Hz Capacity		56.6			60.5Hz Output		0.0

Table O-196. Unit Commitment and Dispatch 2025

Table O-196 shows the unit commitment and dispatch for the typical hour (2/26/25, 3:00 AM).

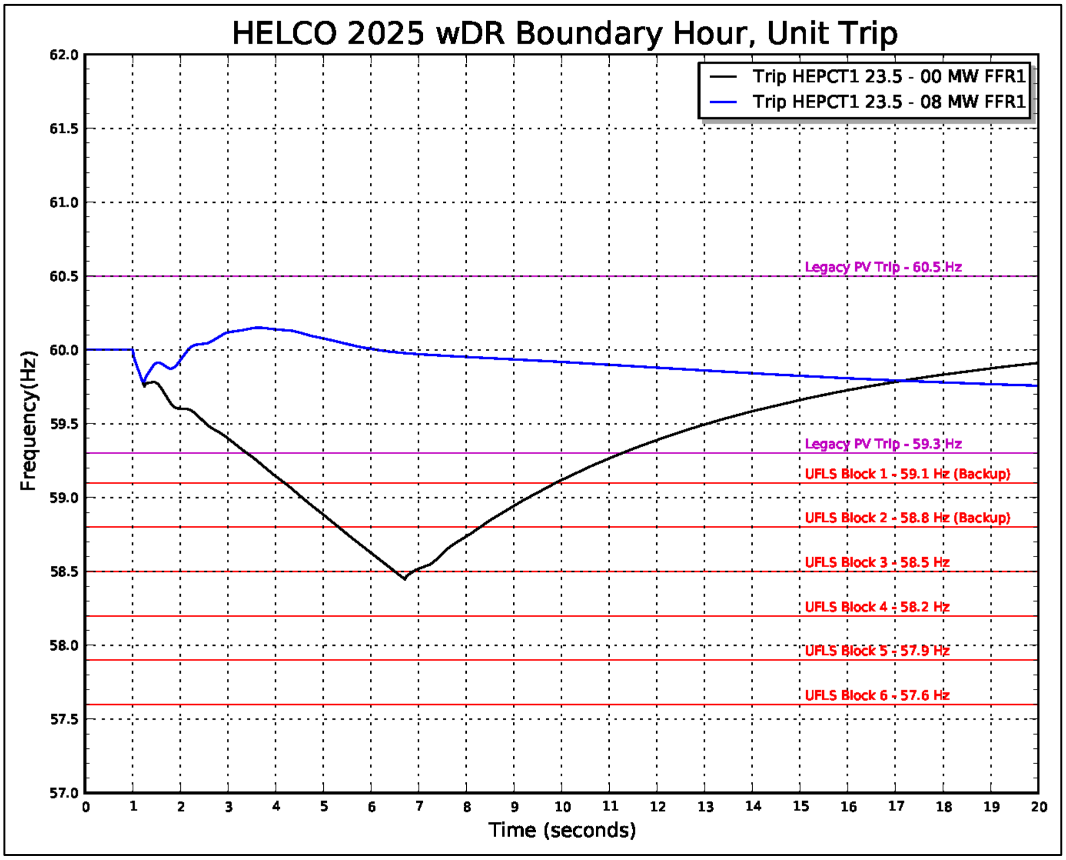

Figure O-414. Frequency Response Profile for FFR1 Boundary Hour

Figure O-414 shows the frequency response profile for a HEP CT1 trip at 23.5 MW. System kinetic energy is 594 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 8 MW.

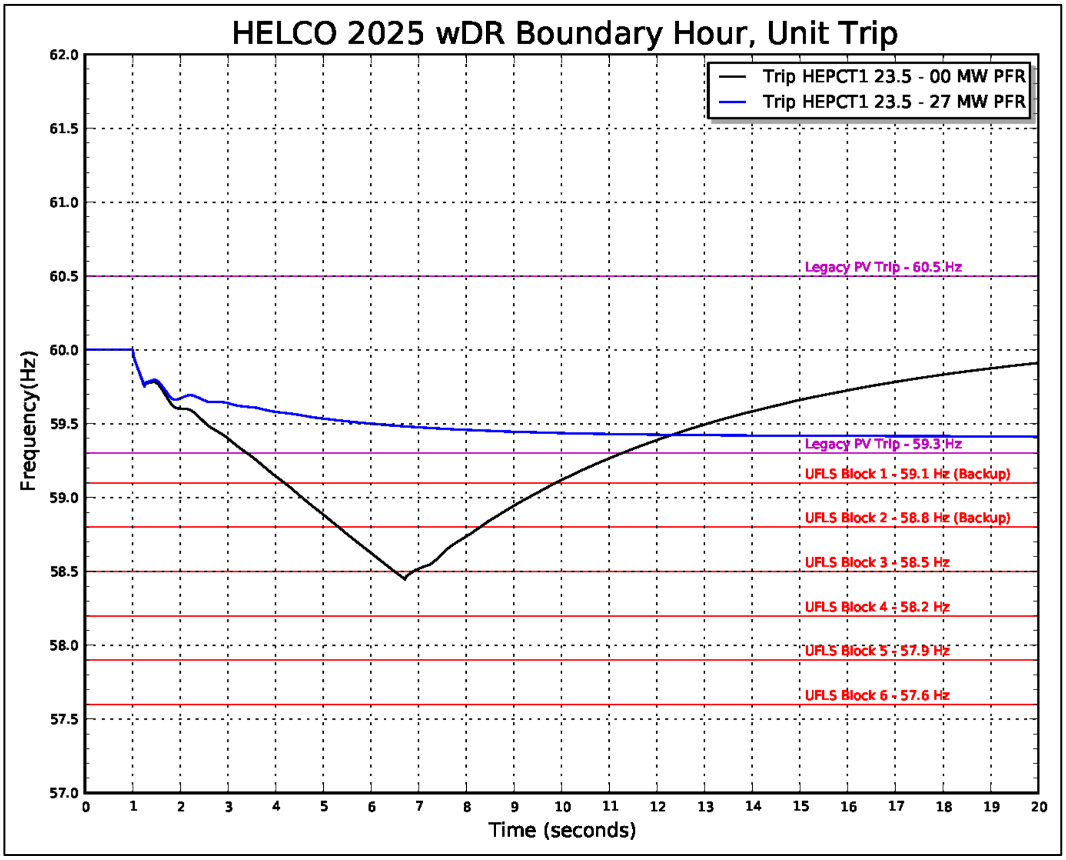

Figure O-415. Frequency Response Profile for PFR Boundary Hour

Figure O-415 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 27 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

2030

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

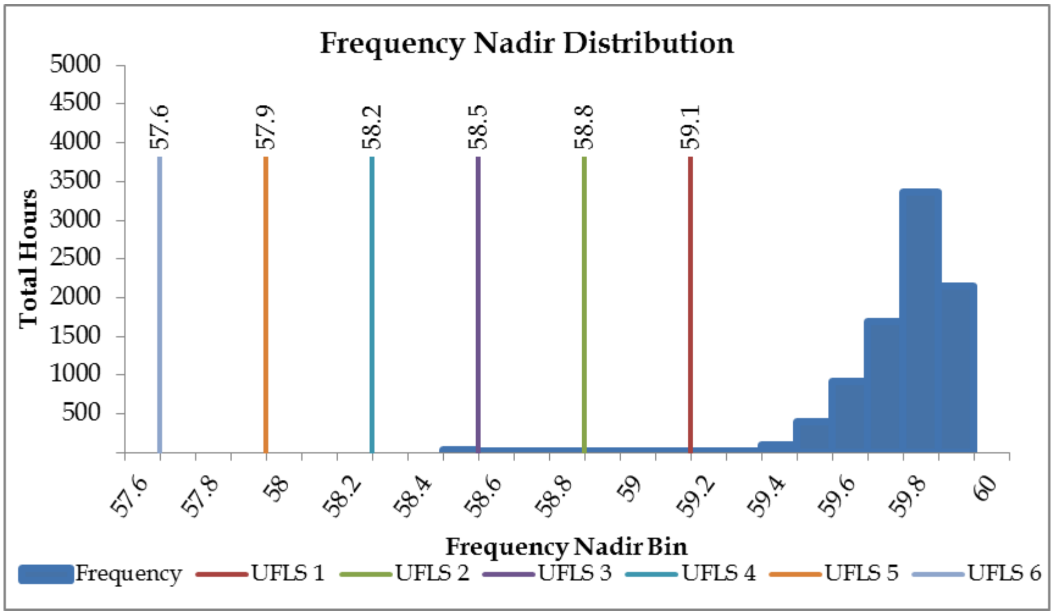

Figure O-416. Frequency Nadir Histogram 2030

Figure O-416 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 31 hours was 12:00 AM on Friday, January 25. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

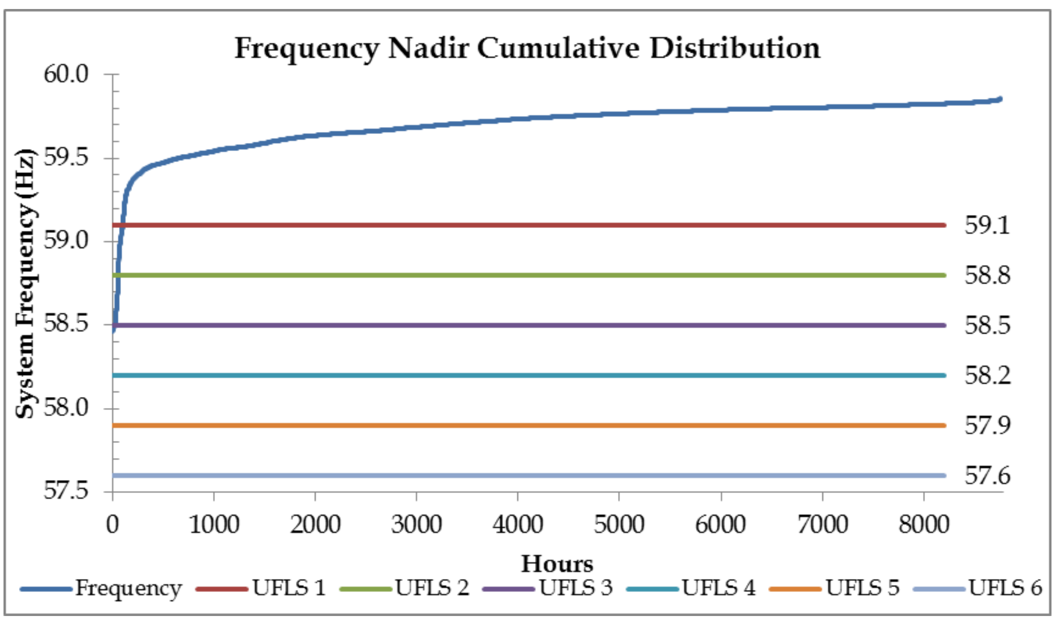

Figure O-417. Frequency Nadir Duration Curve 2030

Figure O-417 shows the frequency nadir duration curve for the Post April DR resource plan in 2030. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 31 hours of the year.

Unit Commitment Order	Unit Ratings					DR - HEP STCC Trip Boundary Fri 1/25/30 Hour 24		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.0	5.5	14.0
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Geo1	20.0		5.00	40.0	200	20.0	0.0	
Geo2	20.0		5.00	40.0	200	20.0	0.0	
Biomass1	20.0		3.16	28.0	88			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.9		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Wind2	20.0	0.0						
Hydro	16.8	0				4		
Wind	91.0	0				0		
DG-PV	148.3	0						
Total Kinetic Energy							794	
Total Load							105	
Total Thermal Generation							101	
Total Renewable Generation							4	
Total Storage							0	
Total Generation							105	
Excess Generation							0	
Total Up Regulation							5	
Total Down Regulation							30	
Legacy DG-PV	59.3Hz Capacity			7.9		59.3Hz Output		0.0
	60.5Hz Capacity			56.6		60.5Hz Output		0.0

Table O-197. Unit Commitment and Dispatch 2030

Table O-197 shows the unit commitment and dispatch for the typical hour (1/25/30, 12:00 AM).

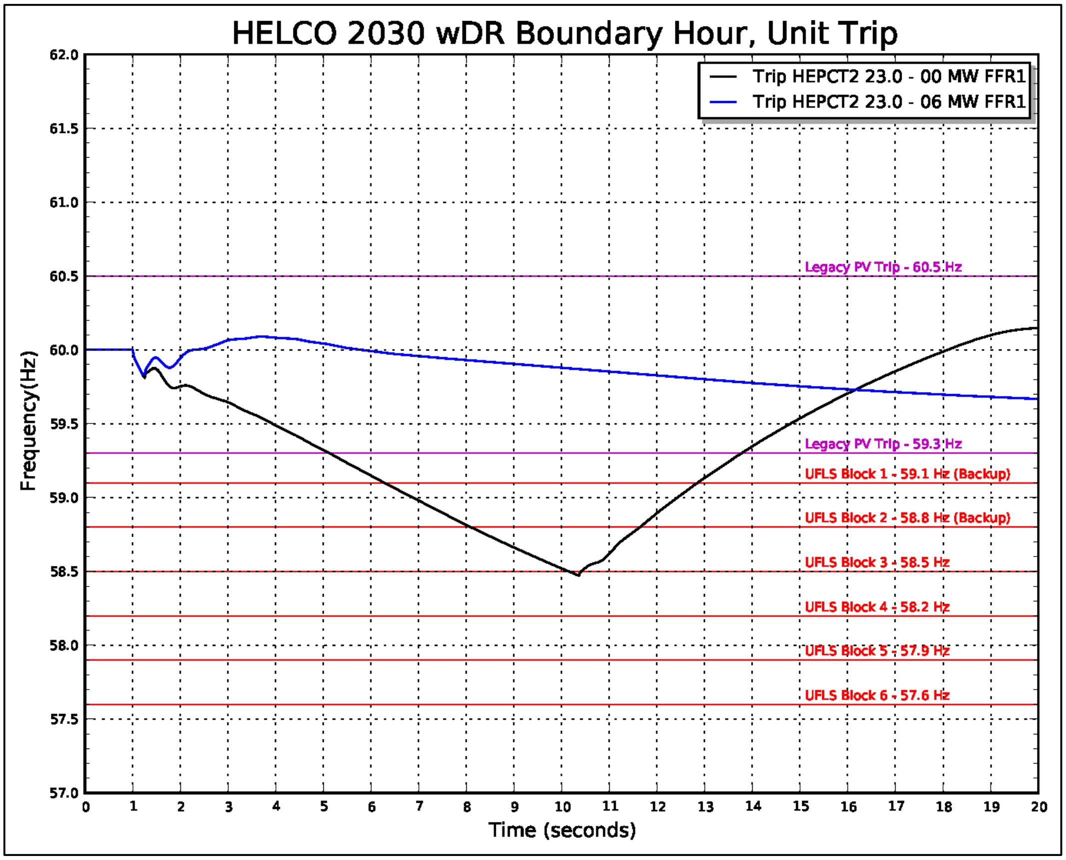

Figure O-418. Frequency Response Profile for FFR1 Boundary Hour

Figure O-418 shows the frequency response profile for a HEP CT2 trip at 23 MW. System kinetic energy is 794 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 6 MW.

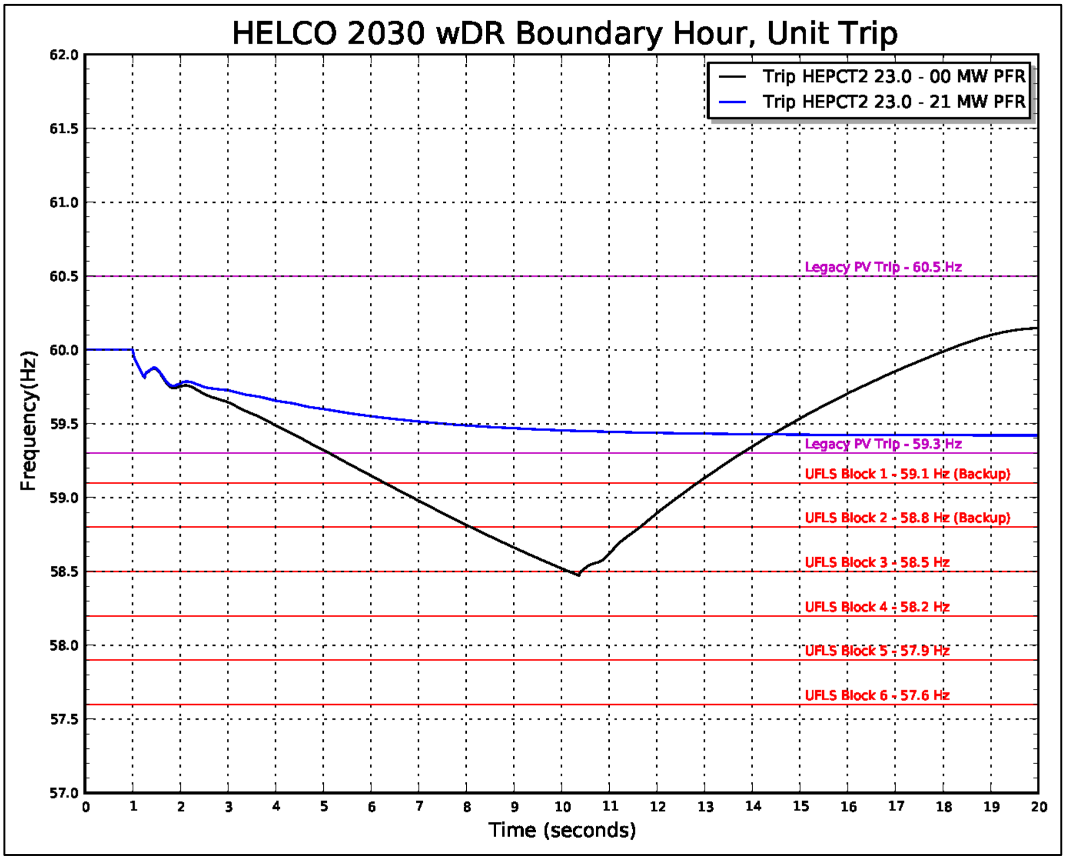

Figure O-419. Frequency Response Profile for PFR Boundary Hour

Figure O-419 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 21 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

2045

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. One hour was selected from the production cost simulation data to represent a boundary condition.

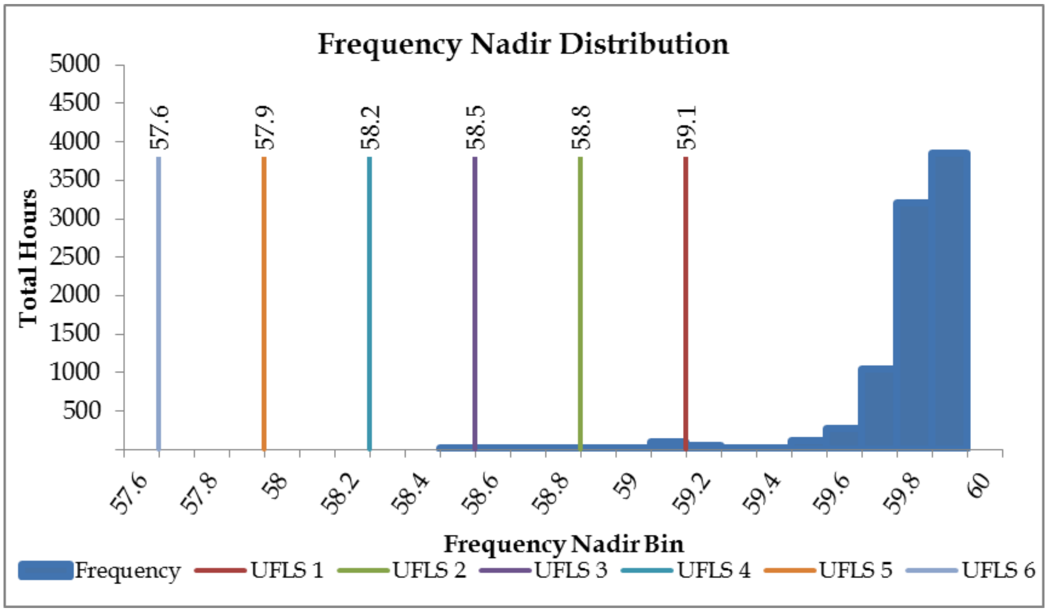

Figure O-420. Frequency Nadir Histogram 2045

Figure O-420 shows the frequency nadir histogram for N-1 generator contingency events for the entire year. The boundary hour was selected from the hourly distribution of 20 hours was 1:00 AM on Friday, January 27. The frequency nadir range for the typical hour is 58.4- 58.5 Hz that requires three blocks of UFLS to stabilize system frequency.

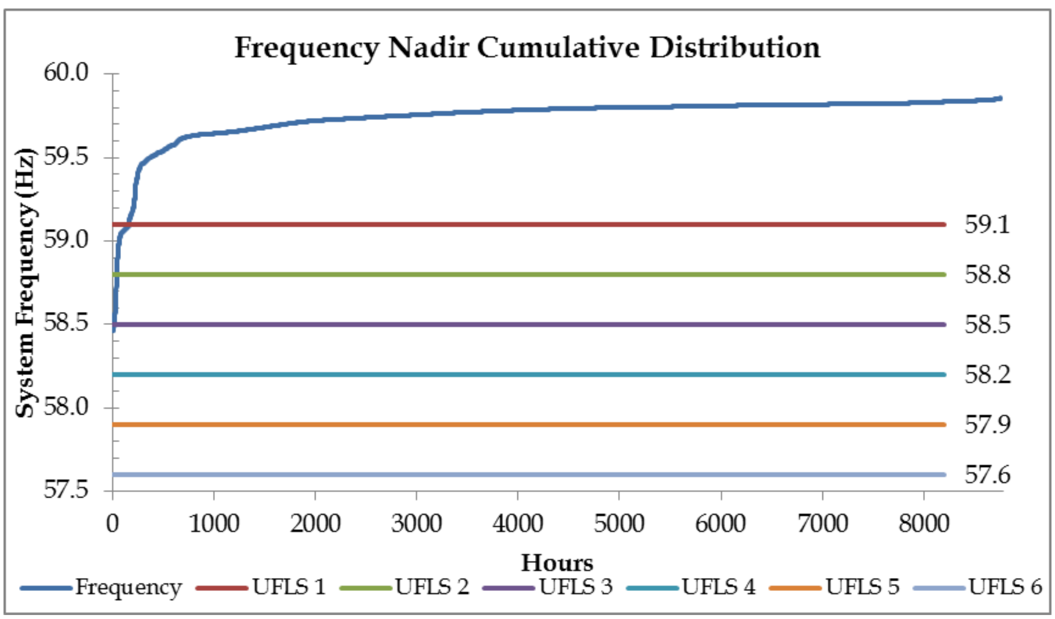

Figure O-421. Frequency Nadir Duration Curve 2045

Figure O-421 shows the frequency nadir duration curve for the Post April DR resource plan in 2045. The system is at risk of non-compliance with the UFLS requirements of TPL-001 for 20 hours of the year.

Unit	Unit Ratings					DR - HEP STCC Trip Boundary Fri 1/27/45 Hour 1		
	Pmax	Pmin	Inertia H	Unit MVA	Unit K.E.	Pgen	up reg (spin)	down reg
PGV	38.0	22.0	2.94	59.4	174	38.0	0.0	16.0
Keahole STCC	25.0	7.0	3.13	46.5	146			
Keahole DTCC	54.0	7.0	2.77	71.8	199			
Keahole CT4	20.0	7.0	2.10	25.2	53			
Keahole CT5	20.0	7.0	2.10	25.2	53			
HEP STCC	28.5	9.0	1.96	58.9	116	23.8	4.7	14.8
HEP DTCC	60.0	18.5	1.78	94.4	168			
Hill 5	13.5	5.0	2.20	15.6	34			
Hill 6	20.5	8.0	2.53	27.5	70			
Puna	15.5	6.0	4.63	18.8	87			
Keah CT2	13.8	5.0	4.44	22.2	99			
Puna CT3	20.0	7.0	4.96	29.6	147			
Diesels (x9)	2.5	0.8	0.70	3.4	2			
Geo1	20.0		5.00	40.0	200	20.0	0.0	
Geo2	20.0		5.00	40.0	200	20.0	0.0	
Biomass1	20.0		3.16	28.0	88			
Synch. Cond. 1	0.0	0.0	2.00	15.6	31	0.0	Synch. Cond.	
Synch. Cond. 2	0.0	0.0	2.00	18.8	38	0.0	Synch. Cond.	
HELCO Hydro	4.7	0.0	1.07	5.6	6	2.4		
Wailuku Hydro	12.1	0.0	2.42	12.2	30	1.8		
Apollo	20.5	0.0						
HRD	10.5	0.0						
Wind1	20.0	0.0						
Wind2	20.0	0.0						
Hydro	16.8	0				4		
Wind	91.0	0				0		
DG-PV	191.0	0						
Total Kinetic Energy						794		
Total Load						106		
Total Thermal Generation						102		
Total Renewable Generation						4		
Total Storage						0		
Total Generation						106		
Excess Generation						0		
Total Up Regulation						5		
Total Down Regulation						31		
Legacy DG-PV	59.3Hz Capacity		0.0			59.3Hz Output		0.0
	60.5Hz Capacity		0.0			60.5Hz Output		0.0

Table O-198. Unit Commitment and Dispatch 2045

Table O-198 shows the unit commitment and dispatch for the typical hour (1/27/45, 1:00 AM).

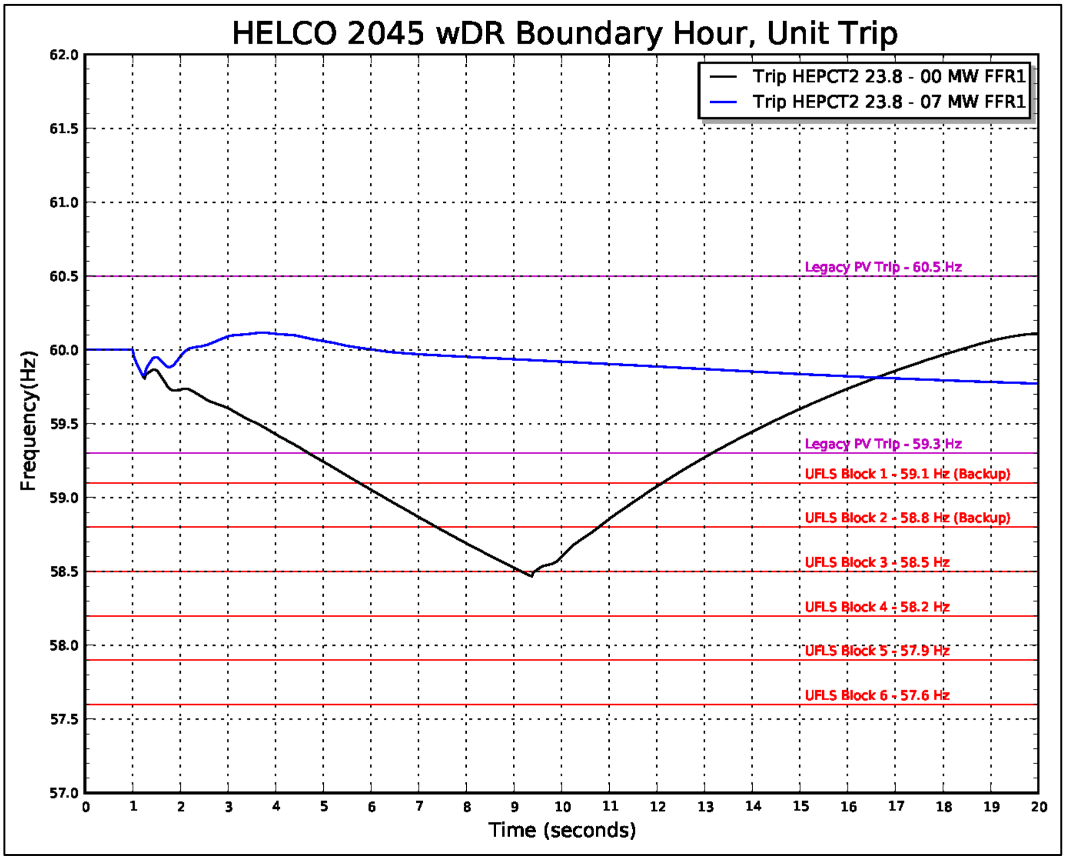

Figure O-422. Frequency Response Profile for FFR1 Boundary Hour

Figure O-422 shows the frequency response profile for a HEP STCC trip at 23.8 MW. System kinetic energy is 794 MW-sec. With no FFR, the frequency nadir breaches 58.5 Hz and three blocks of UFLS are required to stabilize system frequency. The capacity of FFR1 required to bring the system into compliance with TPL-001 is 7 MW.

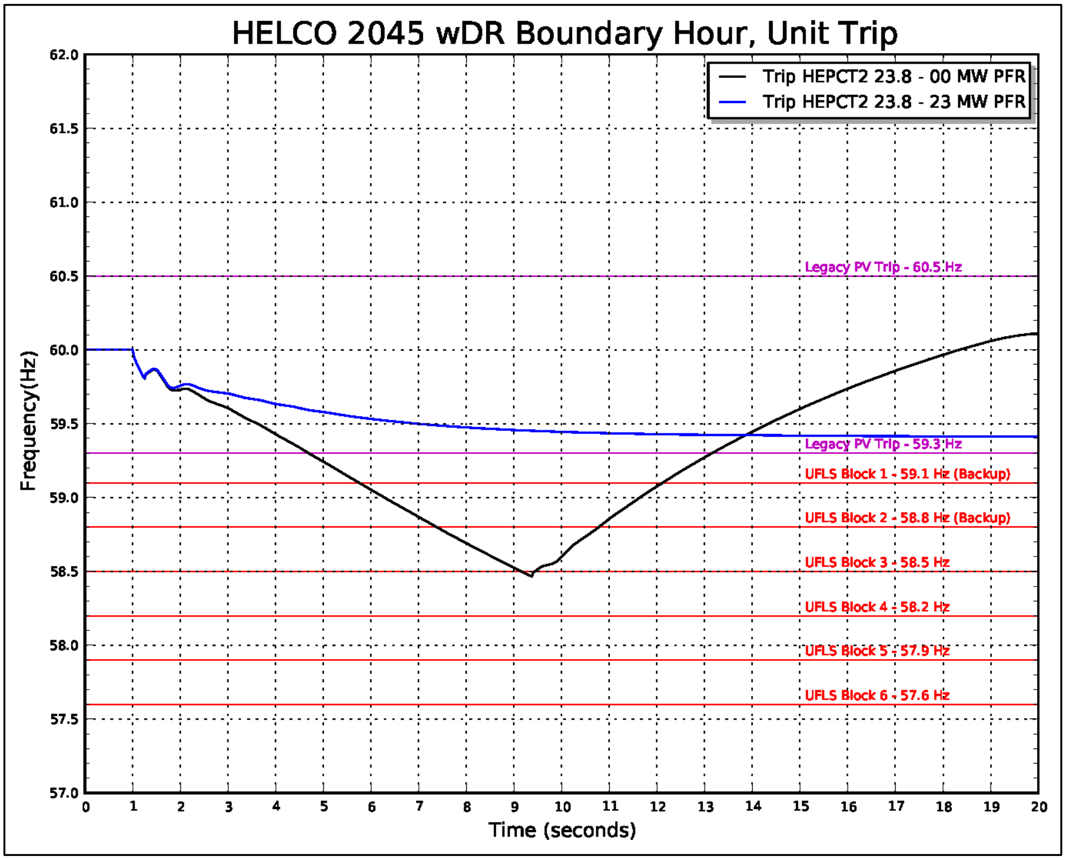

Figure O-423. Frequency Response Profile for PFR Boundary Hour

Figure O-423 shows the frequency response profile for the PFR analysis. The PFR capacity required to meet the requirements of TPL-001 is 23 MW. This is in addition to the 5 MW of upward regulation from thermal generation.

E3 Resource Plan Assessment

The full scope of the system security analysis was not completed for the E3 resource plans. Analysis and assessment focused on the No LNG; High DG-PV plan.

E3 - No LNG; High DG-PV

- MVA Screening (2019 – 2030): Additional synchronous condensers required in 2022to meet the 80 MVA minimum fault current requirement.
- Loss of Generation Screening (2019 – 2030): Screening results indicate degraded system performance stating in 2020. The E3 plan has 485 hours that requires additional frequency response resource to meet TPL-001. The Post April DR plan had 71 hours. The hours at risk increase to 908 in 2025 and 3740 in 2030. This is attributed to a reduction in load to the point where the df/dt UFLS scheme is ineffective.

- 69 kV Fault Screening (2019 – 2022): All normally cleared faults were unstable in 2022 because of the different resource mix. The only synchronous units on the system are PGV and the hydro units.

Hawai'i Island Summary

The system security analysis determines technology-neutral requirements for each resource plan to ensure compliance with TPL-001. Analysis focused on 2019 through 2021 to ensure the resource plans meet system security requirements through the 5-year action plan period. System security analyses include QV analysis, loss of generation analysis, and fault analysis for years 2019-2021. Loss of generation contingency analysis was performed for select years beyond 2021.

Minimum Fault Current

A minimum fault current analysis was not performed for Hawai'i. The minimum fault current requirement is based on the current must-run requirements for synchronous units. The Hawai'i system requires 80 MVA of fault current capacity of which 25 MVA must be connected on the West side of the island. This requirement presumes protective relay schemes are currently operating as designed. This does not ensure the system has sufficient fault current to meet transient voltage stability requirements. More analysis is required to ensure protective relay schemes are operational and transient voltage stability is maintained.

QV Analysis

The Hawai'i transmission system is designed to operate with one transmission line out of service (N-1) while maintaining a minimum bus voltage of 0.90 PU. For the purpose of this analysis, bus voltage is maintained at 0.95 PU to add a margin of stability.

Only synchronous generators and synchronous condensers provide fault current to meet the minimum fault current requirements. Therefore, only synchronous condensers are evaluated in these analyses since resource plans tend to displace must-run units.

For Hawai'i, the critical busses with the highest MVAR demand are the Anaeho'omalu, Keahole, Kealia, and Keamuku busses. These critical busses determine the reactive power requirements for the system.

A new 25 MVA synchronous condenser is required in 2020 for both the Theme 3 No-DR and the Post April DR plans.

Loss of Generation Analysis

Simulations were performed for the largest loss of generation contingency event to determine the frequency response reserve requirements to bring the system into compliance with TPL-001. Two hours were selected from the production cost simulation data to represent a typical condition and a boundary condition.

For the Theme 3 No-DR resource plan, analysis was performed to determine the capacities of FFR1, FFR2, and PFR required to bring the system into compliance with TPL-001. The capacity of FFR1 required to bring the system into compliance with TPL-001 in 2019 is 6 MW for a typical hour. Table O-207 (page O-618) shows the results of the analysis.

For the Post April DR resource plan, analysis was performed to determine the capacities of FFR1 and PFR required to bring the system into compliance with TPL-001. Hawai'i does not have capacities of FFR2 in their Demand Response portfolio. The capacity of FFR1 required to bring the system into compliance with TPL-001 in 2019 is 9 MW for a boundary hour. Table O-208 (page O-618) shows the results of the analysis.

69 kV Fault Analysis

Analysis was performed to determine the system impacts of electrical faults on the transmission system through the 5-year action plan. Results indicate that the system is susceptible to collapse on normally cleared three-phase faults in 2019.

Non-exhaustive sensitivity analyses were performed for normally cleared faults to stabilize system frequency and bring the system into compliance with TPL-001. Simulations were performed to determine the capacity of PFR required to bring the system into compliance with TPL-001 and to evaluate 5-cycle clearing time to simulate performance of dual pilot or dual differential relay schemes. Table O-199 shows the results of the PFR analysis to bring the Hawai'i system into compliance with TPL-001.

Year	PFR (MW)	
	No DR	DR
2019	19	10
2020	18	16
2021	17	None

Table O-199. Summary of Results PFR Analysis

The 2021 Post April DR plan meets the requirements of TPL-001 because Keahole DTCC is running. Further analysis is required to determine optimal mitigating strategies to maintain system security.

TPL-001 TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-2 was HI-TPL-001. The standard was revised to reflect the distinct electrical systems for O‘ahu, Maui, and Hawai‘i Island. Lana‘i and Moloka‘i were removed from HI-TPL-001-02 because they are 12 kV distribution systems.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions become approved when this proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Base Year: The 2011 Balancing Authority’s transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate a fault. (Source: Glossary of Terms Used in NERC Reliability Standards; Term Approved August 4, 2011.)

Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet reliability requirements in Table O-200.

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady-state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Frequency Bias: A value expressed in MW/0.1 Hz that is set into the Automatic Generation Control's (AGC) Area Control Error (ACE) algorithm that allows the Balancing Authority to control system frequency.

Frequency Response: The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hz (MW/0.1 Hz)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the positions identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection Systems are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System or Under Voltage Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAR), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include under-frequency or under-voltage load shedding or out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission Line: A system of structures, wires, insulators, and associated hardware that carry electrical energy form one point to another in an electric power system. Lines are operated at relatively high voltages varying from nominal 69 kV up to 138 kV.

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The facilities are divided into three island systems.

O‘ahu: 2015 Data

- Daytime peak load: 1,110 MW
- Daytime minimum load: 551 MW
- Nighttime peak load: 1,204 MW
- Nighttime minimum load: 506 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 482.6 MVA

Maui: 2015 Data

- Daytime peak load: 180.9 MW
- Daytime minimum load: 88.6 MW
- Nighttime peak load: 206.6 MW
- Nighttime minimum load: 74.5 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 101.3 MVA

Hawai‘i Island: 2015 Data

- Daytime peak load: 173.1 MW
- Daytime minimum load: not applicable
- Nighttime peak load: 191.5 MW
- Nighttime minimum load: 82.6 MW
- Minimum total capacity of synchronous generation needed to provide adequate system fault current: 140 MVA

Effective Date: April 1, 2016

Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table O-200.

R1.1. System models must represent:

R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations.

R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

R1.2.1. Each BA system will be planned to meet the requirements of Table O-200.

R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable performance criteria defined in Table O-200.

R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table O-200.

R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response, or reserve response will withstand contingency events defined in Table O-200.

R1.2.5. The system will be planned such that all generation, reserves, regulation, and voltage control resources will withstand the most severe voltage ride-through requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation, and voltage control resources will withstand contingency events defined in Table O-200.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 under-frequency load shedding. Stability will be defined such that the system will survive the first swing stability and the second swing, and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within five seconds of the initiating event.

R1.2.8. The system will be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and Table O-200.

R2. The BA must prepare a Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady-state analyses, short circuit analyses, and stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, one or more sensitivity cases must demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services.
- Typical generation scenarios including outage of the typically operated generation sources.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table O-200 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady-state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6.

- Minimum short circuit current for proper relay operation: The minimum short circuit current for each BA is specified in the Introduction.
- Maximum short circuit current interrupting capabilities of the breakers must be within the limits for proper breaker operation. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response, and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, one or more sensitivity cases must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements for steady-state, short circuit, or Stability analysis:

R2.6.1. The study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. No material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table O-200 when the analysis indicates an inability of the system to meet the performance requirements, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments, but the planned system must continue to meet the performance requirements in Table O-200. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady-state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives.

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table O-200, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve the required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady-state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1 and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table O-200 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 and R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady-state or ride-through voltage limitations. Include in the assessment any assumptions made.
- Tripping of transmission elements where loadability limits are exceeded.

- Tripping of generation and other resources (including distributed resources) where ride-through capabilities are exceeded.

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady-state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table O-200 that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table O-200 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the planning assessment (as described in R2.4 and R2.5), the BA must perform the contingency analyses listed in Table O-200. The studies must be based on computer simulation models using data provided in R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table O-200 based on the Contingency list created in R4.4. For planning events P1 through P4:

R4.1.1. No generating unit can pull out of synchronism.

R4.1.2. Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.

- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-through capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators, and power flow controllers.

R4.4. Those planning events in Table O-200 that are expected to produce more severe system impacts on its portion of the system must be identified and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table O-200 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA shall have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, transient voltage response, transmission facilities overloading criteria, and dynamic stability criteria (voltage and frequency). For transient voltage response, the criteria shall at the minimum specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA shall define and document, within their Planning Assessment, the criteria or the methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding.

Planning Events

Planning Event	Initial Condition	Event	Non-Consequential Load Shed			UFLS or UVLS		
			O'ahu	Maui	Hawai'i Island	O'ahu	Maui	Hawai'i Island
P0: No Contingency	Normal system N-1 Maintenance N-2 Maintenance	None	n/a	n/a	n/a	None	None	None
P1.1: Loss of One Generating Unit	Normal system	Unit Trip Bus Fault	None	None	None	None	15%	15%
P.1.2: Loss of One Transmission Element	Normal system	SLG, 2Ø, 3Ø, Breaker Fail	None	None	None	None	None	None
P2.1: Loss of Two Generating Units	Normal system	Unit Trip Bus Fault	tbd	tbd	tbd	tbd	tbd	tbd
P2.2: Loss of Two Transmission Elements	N-1	SLG, 2Ø, 3Ø, Breaker Fail	None	tbd	tbd	None	tbd	tbd
P3.1: Loss of Multiple Generating Units	Normal system	Loss of Combined Cycle unit	tbd	tbd	tbd	tbd	tbd	tbd
P3.2: Loss of Multiple Transmission Elements	N-2	SLG, 2Ø, 3Ø, Breaker Fail	tbd	tbd	tbd	tbd	tbd	tbd
P4: Catastrophic Event	Normal system	Loss of Generating Station Loss of Transmission Corridor	tbd	tbd	tbd	tbd	tbd	tbd

Table O-200. Transmission Performance Requirements

Measures

M1. The BA must provide evidence, in hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady-State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence (such as electronic or hard copies) that it has prepared an annual Planning Assessment of its portion of the system in accordance with R2.

M3. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R3.

M4. The BA must provide dated evidence (such as electronic or hard copies) of the studies utilized in preparing the Planning Assessment in accordance with R4.

M5. The BA must provide dated evidence (such as electronic or hard copies) of the documentation specifying the criteria for acceptable system steady-state voltage limits, post contingency voltage deviations, and transient voltage utilized in preparing the Planning Assessment in accordance with R5.

M6. The BA must provide dated evidence (such as electronic or hard copies) of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with R6.

Compliance

C1. Compliance Monitoring Process

C1.1. Compliance Enforcement Authority: Hawai‘i Public Utilities Commission or its designee.

C1.2. Data Retention: The BA must retain data or evidence to show compliance as identified unless directed by the Commission (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with R1 and M1.
- The Planning Assessments performed since the last compliance audit in accordance with R2 and M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R3 and M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with R4 and M4.
- The documentation specifying the criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with R5 and M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions (such as cascading, voltage instability or uncontrolled islanding) in support of its Planning Assessments since the last compliance audit in accordance with R6 and M6.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

C1.3. Compliance monitoring and enforcement processes:

- Compliance Audits: The Commission (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-certifications
- Spot checking
- Compliance violation investigations
- Self-reporting
- Complaints

C2. Levels of non-compliance for R1 and M1:

C2.1. Level 1: The BA's system model failed to represent one of the requirement in R1.1.1 through R1.1.5.

C2.2. Level 2: The BA failed to meet all the requirements of C2.1 Level 1.

C3. Levels of non-compliance for R2 and M2:

C3.1. Level 1: The BA failed to comply with R2.6.

C3.2. Level 2: The BA failed to meet all the requirements of C3.1 Level 1.

C4. Levels of non-compliance for R3 and M3:

C4.1. Level 1: The BA did not identify planning events as described in R3.4 or extreme events as described in R3.5.

C4.2. Level 2: The BA failed to meet all the requirements of C4.1 Level 1.

C5. Levels of non-compliance for R4 and M4:

C5.1. Level 1: The BA did not identify planning events as described in R4.4 or extreme events as described in R4.5.

C5.2. Level 2: The BA failed to meet all the requirements of C5.1 Level 1.

C6. Levels of non-compliance for R5 and M5:

C6.1. Level 1: not applicable.

C6.2. Level 2: The BA does not have criteria for acceptable system steady-state voltage limits, post-contingency voltage deviations, or the transient voltage response for its system for R5 and M5.

C7. Levels of non-compliance for R6 and M6:

C7.1. Level 1: not applicable.

C7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in R6 and M6.

FREQUENCY RESPONSE ANALYSIS RESULTS

O'ahu Frequency Response Results

Freq Response Reserves	Case	2019			2020			2021			2022			2023			2025			2030			2045		
		Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)
FFR1	Typical	AES 189	4518	120	AES 189	4161	120	AES 189	3735	130	AES 189	3378	140	K5 135	3546	100	GE CT 151	3446	120	GE CT 151	2777	120	OSW 165	1002	140
	Boundary	AES 189	3735	140	AES 189	3378	140	AES 189	3378	140	AES 189	2686	150	K5 128	1651	100	GE CT 151	3410	120	GE CT 151	3435	130	OSW 165	1002	150
FFR2	Typical	AES 189	4518	130	AES 189	4161	130	AES 189	3735	140	AES 189	3378	150	K5 135	3546	100	GE CT 151	3446	120	GE CT 151	2777	120	OSW 165	1002	N/A
	Boundary	AES 189	3735	150	AES 189	3378	150	AES 189	3378	150	AES 189	2686	170	K5 128	1651	130	GE CT 151	3410	120	GE CT 151	3435	130	OSW 165	1002	N/A
PFR	Typical	AES 189	4518	310	AES 189	4161	320	AES 189	3735	350	AES 189	3378	350	K5 135	3546	210	GE CT 151	3446	260	GE CT 151	2777	260	OSW 165	1002	510
	Boundary	AES 189	3735	370	AES 189	3378	370	AES 189	3378	370	AES 189	2686	420	K5 128	1651	360	GE CT 151	3410	240	GE CT 151	3435	250	OSW 165	1002	540
FFR1 (K5 Trip)	Typical	K5 135	4092	90	K5 135	4161	80	K5 135	3735	90	K5 135	3378	100												
	Boundary	K5 135	3735	100	K5 135	3378	110	K5 135	3378	100	K5 135	2787	110												
FFR2 (K5 Trip)	Typical	K5 135	4092	90	K5 135	4161	80	K5 135	3735	90	K5 135	3378	100												
	Boundary	K5 135	3735	100	K5 135	3378	110	K5 135	3378	110	K5 135	2787	110												
PFR (K5 Trip)	Typical	K5 135	4092	210	K5 135	4161	210	K5 135	3735	230	K5 135	3378	230												
	Boundary	K5 135	3735	260	K5 135	3378	250	K5 135	3378	260	K5 135	2787	290												

Table O-201. Summary of Result Frequency Response Analysis – Theme 5 No DR: O'ahu

Freq Response Reserves	Case	2019				2020				2021				2022				2023				2025				2030				2045			
		Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)	Contingency (MW)	KE (MJ)	FFR2 (MW)	Requirement (MW)
FFR1	Typical	AES 189	4098	47.4	70	AES 189	3838	48.8	70	AES 189	4087	46.8	70	AES 189	3869	38	90	K5 135	4780	49.1	20	GE 151	4058	41	40	GE 151	4276	32.5	60	OSW 159	1146	48	70
	Boundary	AES 189	3502	25.6	110	AES 189	3433	34.8	100	AES 189	3586	32.2	100	AES 189	3416	32.8	100	K5 135	3564	35.1	50	GE 151	3467	31.9	70	GE 150	3555	32.7	90	OSW 145	1002	40	90
PFR	Typical	AES 189	4098	47.4	200	AES 189	3838	48.8	200	AES 189	4087	46.8	190	AES 189	3869	38	200	K5 135	4780	49.1	50	GE 151	4058	41	90	GE 151	4276	32.5	120	OSW 159	1146	48	200
	Boundary	AES 189	3502	25.6	290	AES 189	3433	34.8	260	AES 189	3586	32.2	260	AES 189	3416	32.8	260	K5 135	3564	35.1	110	GE 151	3467	31.9	130	GE 150	3555	32.7	180	OSW 145	1002	40	320
FFR1 (K5 Trip)	Typical	K5 135	4104	47.4	30	K5 135	3678	48.8	40	K5 135	3996	46.8	40	K5 135	3847	38	60																
	Boundary	K5 135	3411	25.6	70	K5 135	3411	34.8	60	K5 135	3591	32.2	60	K5 135	3660	32.8	60																
PFR (K5 Trip)	Typical	K5 135	4104	47.4	100	K5 135	3678	48.8	100	K5 135	3996	46.8	100	K5 135	3847	38	120																
	Boundary	K5 135	3411	25.6	160	K5 135	3411	34.8	130	K5 135	3591	32.2	140	K5 135	3660	32.8	130																

Table O-202. Summary of Results Frequency Response Analysis – Post April DR: O'ahu

Maui Frequency Response Results

Freq Response Reserves	Case	2019			2020			2021			2023			2030			2045		
		Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)
FFR1	Typical	KWP I 29	300	9	KWP I 27	305	8	KWP I 27	437	8	WIND I 30	295	12						
	Boundary	KWP I 30	300	10	WIND I 30	316	9	KWP I 29.7	597	12	KWP I 30	295	11	KWP I 30	469	4	KWP I 30	638	0
FFR2	Typical	KWP I 29	300	11	KWP I 27	305	10	KWP I 27	437	9	WIND I 30	295	14						
	Boundary	KWP I 30	300	13	WIND I 30	316	11	KWP I 29.7	597	15	KWP I 30	295	13	KWP I 30	469	5	KWP I 30	638	0
PFR	Typical	KWP I 29	300	16	KWP I 27	305	15	KWP I 27	437	14	WIND I 30	295	21						
	Boundary	KWP I 30	300	19	WIND I 30	316	17	KWP I 29.7	597	21	KWP I 30	295	20	KWP I 30	469	8	KWP I 30	638	0

Table O-203. Summary of Results Frequency Response Analysis - Theme 3 No DR: Maui

Freq Response Reserves	Case	2019			2020			2021			2022			2023			2030			2045		
		Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)
FFR1	Typical	KWP I 29.7	299	8	KWP I 29.1	292	8	KWP I 29.5	292	9	KWP I 29.9	273	14	KWP I 29.2	316	7	KWP I 29.4	403	7			
	Boundary	KWP I 29.6	270	9	KWP I 29.8	292	8	KWP I 29.8	292	8	KWP I 30	273	10	KWP I 29.2	229	14	KWP I 29.2	403	8	LS BESS 30	403	2
PFR	Typical	KWP I 29.7	299	16	KWP I 29.1	292	15	KWP I 29.5	292	15	KWPI 29.9	273	23	KWP I 29.2	316	13	KWP I 29.4	403	13			
	Boundary	KWP I 29.6	270	15	KWP I 29.8	292	14	KWP I 29.8	292	14	KWP I 30	273	14	KWP I 29.2	229	22	KWP I 29.2	403	14	LS BESS 30	403	3

Table O-204. Summary of Frequency Response Analysis Post April DR: Maui

Lanaʻi Frequency Response Results

Freq Response Reserves	Case	2019			2020			2021			2030			2045		
		Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)	Contingency (MW)	KE (MJ)	Requirement (MW)
FFR1	Typical															
	Boundary	L7 1.2MW	9	1.25	L8 2.2MW	9	2.4	L8 2.17MW	9	2.4	L8 2.2MW	9	2.4	L8 2.2MW	9	0
PFR	Typical															
	Boundary	L7 1.2MW	9	1.25	L8 2.2MW	9	2.4	L8 2.17MW	9	2.4	L8 2.2MW	9	2.4	L8 2.2MW	9	0

Table O-205. Summary of Results Frequency Response Analysis: Lana'i

Molokaʻi Frequency Response Results

Freq Reponse Reserves	Case	2019			2020			2030			2045		
		Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)	Contingency	KE (MJ)	Requirement (MW)
FFR1	Typical												
	Boundary	D9 2.2MW	6	2.75	D9 2.1MW	6	2.5	D9 2.2MW	6	2.5	D9 2.1MW	6	2.15
PFR	Typical												
	Boundary	D9 2.2MW	6	3.25	D9 2.1MW	6	3.25	D9 2.2MW	6	3.25	D9 2.1MW	6	3.25

Table O-206. Summary of Results Frequency Response Analysis: Moloka'i

Hawai‘i Island Frequency Response Results

Freq Response Reserves	Case	2019 Contingency (MW)	2019 KE (MJ)	2019 Requirement (MW)	2020 Contingency (MW)	2020 KE (MJ)	2020 Requirement (MW)	2021 Contingency (MW)	2021 KE (MJ)	2021 Requirement (MW)	2025 Contingency (MW)	2025 KE (MJ)	2025 Requirement (MW)	2030 Contingency (MW)	2030 KE (MJ)	2030 Requirement (MW)	2045 Contingency (MW)	2045 KE (MJ)	2045 Requirement (MW)
FFR1	Typical				HEP 22.0	373.5	6	HEP 25.9	373.5	7									
	Boundary	KEAH 23.9	423.6	5	HEP 24.0	373.5	11	HEP 24.7	373.5	8	HEP 23.8	573.5	7	HEP 26.4	773.5	5	HEP 25.7	662	5
FFR2	Typical				HEP 22.0	373.5	6	HEP 25.9	373.5	7									
	Boundary	KEAH 23.9	423.6	5	HEP 24.0	373.5	11	HEP 24.7	373.5	8	HEP 23.8	573.5	7	HEP 26.4	773.5	5	HEP 25.7	662	5
PFR	Typical				HEP 22.0	373.5	19	HEP 25.9	373.5	23									
	Boundary	KEAH 23.9	423.6	18	HEP 24.0	373.5	36	HEP 24.7	373.5	29	HEP 23.8	573.5	24	HEP 26.4	773.5	15	HEP 25.7	662	16

Table O-207. Summary of Results Frequency Response Analysis – Theme 3 No DR: Hawai‘i Island

Freq Response Reserves	Case	2019 Contingency (MW)	2019 KE (MJ)	2019 FFR2 (MW)	2019 Requirement (MW)	2020 Contingency (MW)	2020 KE (MJ)	2020 FFR2 (MW)	2020 Requirement (MW)	2021 Contingency (MW)	2021 KE (MJ)	2021 FFR2 (MW)	2021 Requirement (MW)	2025 Contingency (MW)	2025 KE (MJ)	2025 FFR2 (MW)	2025 Requirement (MW)	2030 Contingency (MW)	2030 KE (MJ)	2030 FFR2 (MW)	2030 Requirement (MW)	2045 Contingency (MW)	2045 KE (MJ)	2045 FFR2 (MW)	2045 Requirement (MW)
FFR1	Typical																								
	Boundary	HEP 28.7	448.6	N/A	8	HEP 28.7	397.8	N/A	9	HEP 28.7	448.4	N/A	6	HEP 23.5	525.8	N/A	8	HEP 23.0	725.8	N/A	6	HEP 23.8	725.8	N/A	7
PFR	Typical																								
	Boundary	HEP 28.7	448.6	N/A	26	HEP 28.7	397.8	N/A	31	HEP 28.7	448.4	N/A	21	HEP 23.5	525.8	N/A	27	HEP 23.0	725.8	N/A	21	HEP 23.8	725.8	N/A	23

Table O-208. Summary of Results Frequency Response Analysis – Post April DR: Hawai‘i Island

P. Consultant Reports

Three consultants worked in concert with the Companies to participate in the modeling and analyses required to develop the December 2016 updated PSIP:

Energy and Environmental Economics (E3) ran their RESOLVE model to develop theoretical least-cost plans; Ascend Analytics ran their PowerSimm Planner model essentially to validate the E3 plans; and Black and Veatch ran their Adaptive Planning for Production Simulation model to evaluate Demand Response for the PSIP action plans.

Each wrote a report of their work. Those reports are included here as submitted, and accepted.

E3: SUMMARY OF RESOLVE FINDINGS

E3 December 2016 PSIP Update

Summary of findings from RESOLVE modeling of Oahu, Maui, and Hawai'i Islands

December 23, 2016

Energy+Environmental Economics

E3 December 2016 PSIP Update

Summary of findings from RESOLVE modeling of Oahu, Maui, and Hawai'i Islands

December 23, 2016

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1: INTRODUCTION

Q1. WHAT WAS ENERGY AND ENVIRONMENTAL ECONOMICS INC (E3) SCOPE OF WORK?

A1. The Companies initially hired E3 in June of 2016 to use its RESOLVE model to look at the potential net benefits provided by interconnecting the island systems via undersea transmission cables. This scope was expanded in August of 2016 to include a range of sensitivities provided by the Companies and stakeholders. E3 used this same model in the previous PSIP filing in April of 2016 and have described the model, results and input assumptions in two different workshops.

E3's deliverables for this round of the PSIP include least cost resource plans for Oahu, Maui and Hawaii as independent, non-interconnected island systems, as well as for grid-interconnected systems, using reference assumptions developed through several weeks of consultations with the Company team. The model results serve a specific purpose in the PSIP – to produce an initial set of least cost recommendations for the 5-year plans that will be both validated and refined by the Companies using both practical interconnection and transmission limitations, feasible block sizes for generation additions and more detailed operational models that look more closely at reliability.

A second set of deliverables includes sensitivity analysis around the reference cases to investigate the impact of different assumptions about how the future will unfold on the decisions made in the 5-year plan. These sensitivities have been determined by the Companies working closely with stakeholders throughout the process.

Q2. WHAT IS THE KEY DIFFERENCE BETWEEN THE ROLE YOU PLAYED IN THE PREVIOUS PSIP FILING AND YOUR WORK HERE?

A2. Our earlier results were produced by the E3 team working independently of the process used by the Companies using a mixture of input assumptions from the company work and our own database looking only at Oahu. In this revision, we have expanded the analysis to include Maui and Hawaii and all input assumptions have been provided by the Company team and revised through close collaboration with them and input from stakeholders, over the last 5 months. We show results of cases defined by the companies and those defined by stakeholders separately. We have also extended our analysis beyond studies of the islands individually to provide a rough upper bound bookend of the value of interconnecting the islands with undersea transmission cables as a first screen to test whether a more detailed intertie study is warranted.

Q3. WHAT WAS THE PROCESS YOU USED TO DEVELOP YOUR FINDINGS IN THIS UPDATED PSIP FILING?

A3. The process was developed based on feedback from stakeholders regarding the lack of transparency in the previous PSIP filing. To increase both the transparency of results and allow third parties to participate more effectively in the process, the methodology, the cases being run, and the inputs assumptions were discussed over two workshops at the HPUC with stakeholders and commission staff. The role of the E3 analysis as a precursor to more detailed modeling being conducted by the Companies was also presented. The input data assumptions are presented in detail for each island in the Appendix to this report.

Our role in this process was not to choose the best plan, but to provide an independent and unbiased assessment of the least cost incremental system capacity investments and dispatch decisions for each island necessary to meet Hawaii's RPS goals under the assumptions defined for the reference and sensitivity cases and make those results and cases equally transparent and accessible to all parties.

Costs were examined from a Total Resource Cost perspective meaning that customer costs for customer-sited generation were considered in the optimizations in both the core and sensitivity cases that allow optimal DGPV resource selection.

Q4. PLEASE BRIEFLY DESCRIBE THE CASES YOU DEVELOPED FOR THE COMPANIES AND STAKEHOLDERS.

A4. Each case was focused on varying certain input parameters to investigate various uncertainties. The key variations in the input parameters for each case are summarized here with further details describing each case listed below.

For each island, we investigate the sensitivity of the least cost resource plan to two major uncertainties for the Companies – the scale of DGPV buildout and the option to invest in LNG resources beginning in 2022. To test both sensitivities, we used the Companies-produced "Market" DGPV forecast and the "High" DGPV forecast as inputs into the RESOLVE model, and for each forecast, we run one case assuming an LNG import hub is built and LNG thermal resources are available (including conversion of various existing resources, with cost data provided by the Companies), and one in which no LNG hub is available. Thus, four cases were run for each island (LNG Market DGPV, LNG High DGPV, No-LNG Market DGPV, No-LNG High DGPV). All of these cases are run assuming that each utility must meet its own RPS constraint independently.

There were several other sensitivities tested. These sensitivities, some performed at the request of the Companies and some at the request of stakeholders, are listed below. To minimize the number of cases produced, these sensitivities, except when noted otherwise, were run using the No-LNG option with the Market DGPV forecast on each island.

- Value of renewable hedge: Ulupono requested that we investigate the sensitivity of the results to a 35% adder to all forecasted fuel prices on each island.
- No-RPS case: The Consumer Advocate requested that we develop a case in which there is no RPS constraint on each island for cost comparison to other cases.
- Enhanced renewable energy potential on Oahu: In the base cases, we use the National Renewable Energy Laboratory (NREL) produced estimates for solar and wind resource potentials on Oahu consistent with using land that has less than a 5% slope. Dr. Fripp, at the request of Ulupono and Blue Planet, has provided us data with increased resource potentials on Oahu consistent with using land up to a 10% slope.
- Paniolo pumped storage and wind plant: Paniolo requested that we substitute the company assumptions for their own cost and performance estimates of a pumped storage and wind resources on Hawai'i Island.
- Military units on Oahu: The base cases assume two military fuel oil units on Oahu (located at Marine Corps Base Hawaii and Joint Base Pearl Harbor-Hickam) will be in service in the early 2020's. A sensitivity case was run in which these units are not assumed to be in service, but the model is given the option of purchasing units of their equivalent size and efficiencies.
- DGPV as model choice: A scenario was run on each island in which the DGPV forecast is completed through 2020, but there is no DGPV forecasted beyond 2020. Instead, in the time-period beyond 2020 the model is given the option of procuring DGPV, similarly to the way in which the model is given the option to procure grid-scale solar or other renewable resources.
- Uncurtailable DGPV case: A scenario was run on each island in which all DGPV resources are assumed to be uncontrollable, as opposed to the base cases in which all DGPV installed after 2020 is assumed to be curtailable. These cases were run using the No-LNG High DGPV forecasts on each island.

Finally, in addition to the individual island cases we run a "Copperplate" case where we treat all three islands (Oahu, Maui, Hawai'i) as one large zone connected with infinite transmission capacity between the islands with no import or export limits. This case is run to investigate the maximum potential benefits of building interisland cables between these islands without regard to the cost of the cable itself. The case is useful as a screen to determine if the cable should be studied further and to determine changes in generation portfolios by island that have the potential to provide the most benefits.

Q5. PLEASE SUMMARIZE THE RESULTS.

A5. The findings are grouped into results of the Company defined cases and results of cases defined by stakeholders. Where possible, we have tried show only a set of simplified model output data to define and highlight the differences between the cases. This output data includes costs normalized to a base or reference case plan and proposed least cost investments over through 2045 designed to minimize the cost of compliance with the 100 percent RPS requirement by island and in the copper plate transmission case.

Results from Company Defined Cases

1. Since the Companies are not requesting an LNG import hub in the near term, the No-LNG cases are used as the reference cases on each island. In this document the No-LNG Market DGPV plan on each island is used as a common point of comparison between costs and build decisions across cases. The comparison of the costs of this plan with the costs of other plans is shown in Table 1 below. The costs of any two cases can be compared by their costs in relation to the No LNG, Market DGPV plan, which has a normalized net present value cost of 1. Table 1 below shows each of the reference case costs as 1 in the middle column of Table 1 below. Investments in LNG, given the EIA fuel price forecast with not hedge adder have lower costs and the higher DGPV forecasts are also higher costs than the reference cases.

Table 1. Total resource cost comparison between Company defined cases (normalized with respect to No-LNG Market DGPV case on each island)

Oahu	Market DGPV	High DGPV
No-LNG	1.00	1.05
LNG	0.92	0.97
Maui	Market DGPV	High DGPV
No-LNG	1.00	1.10
LNG	0.85	0.95
Hawaii	**Market DGPV**	**High DGPV**
No-LNG	1.00	1.18
LNG	0.85	1.05

2. Over the next five years, it is cost effective to take advantage of the federal tax incentives for renewable resources on each of the islands. This incentive drives the results that show that each of the company plans are ahead of the straight-line year by year RPS goal. On Maui and Hawai'i, this is true regardless of LNG status. On Oahu, the No-LNG case results in Oahu staying ahead of the RPS goal, but in the LNG cases Oahu does not significantly exceed the RPS goal.

3. Over the next five years, the amount of tax advantaged renewable energy chosen by RESOLVE is limited by the amount of renewable energy that Companies estimate can be interconnected and delivered safely to loads through 2020. This interconnection limit was estimated by the Companies to be 130MW of wind for Maui, 20MW of wind for Hawaii and 300MW of solar for Oahu; other renewable resources, such as solar on Maui and Hawaii, were not constrained by any interconnection limit, but were also not chosen by RESOLVE.

4. Energy storage or some form of advanced demand response is cost-effective as early as 2020 for Hawaii and in 2022 for Oahu and Maui.

5. The Marine Corps Base Hawaii (MCBH) at Kaneohe Bay and the Joint Base Pearl Harbor-Hickam (JBPHH) were included as planned resources in the base cases. A sensitivity was run where the model was given the option to purchase those units, but they were not selected in the base thermal build; increased amounts of renewable energy (in the No-LNG cases) and other dispatchable LNG resources (in the LNG cases) were chosen to replace this capacity in the short term. In the longer term, in all cases some dispatchable thermal capacity was chosen in 2045.

   As we discuss in response to Question 6 below, the RESOLVE model does not investigate detailed contingencies or system security constraints, and there are reliability benefits to keeping sufficient levels of thermal projects online which RESOLVE is not considering. Furthermore, when RESOLVE chooses not to invest in the military based thermal resources, the model assumes that beyond 2020 there are no interconnection limits or land use issues to constrain the grid in absorbing further renewable energy installations and that all of these new resources, whether located behind or in front of the customer meter, are fully curtailable.

6. The interisland "Copper Plate" cable case substantially increases the renewable builds on the neighbor islands. For example, the proposed renewable resource build on Oahu in the 2020-2022 is reduced from 348 MW to 0; Maui increases from 96MW to 217MW; and, Hawaii increases from 70MW to 814MW. Note that these are unrealistic build amounts given both the near-term timing and the unlimited amounts of grid capacity assumed on each island system.

7. The interisland cable produces sufficiently large benefits related to procurement and energy and capacity savings that we recommend Hawaii continue to conduct more detailed focused analysis on specific configurations that would provide a combination of maximum net benefits and renewable procurement flexibility. Using our screening process, we estimate that a large cable system interconnecting each island could have benefits as large as three billion dollars in present value over the lifetime of the cable. A phase 2 study of the interisland cables would break down the copperplate case into

scenarios that would include (1) specific transmission project costs and operating limitations, and (2) assumptions about the feasibility, timing, and cost constraints of significantly expanded renewable resources on Maui and Hawaii.

In the near term, the resource decisions in the interisland cable case versus the individual island cases do not change on Maui or the Big Island. While the interisland cable case identifies greater renewable build on these islands due to better resource qualities over the long term, the renewable build is constrained by interconnection limitations on each of the islands in the early years. In addition, given the uncertainty of the Phase 2 study findings, we do not recommend that Hawaii conduct its procurement and transmission planning on the individual islands today as if the cable were going to be in place. To avoid any risk of stranding capital investments, we believe that a safer more prudent approach would be focus on optimizing the plans for each island separately over the next 5 years..

8. A number of stakeholders were concerned that the company request for approval in the first 5 years not commit it to an inflexible longer term pathway. In general, we believe that the RESOLVE choices in the first 5 years are fairly robust and provide what now looks like a unique and quickly vanishing opportunity to take advantage of federal tax incentives to benefit electricity consumers. We strongly recommend that Hawaii take maximum advantage of these subsidies as soon as possible.

   Parties asked if anything recommended in the first years would change if we know that the cable were going to be constructed later. There is a change in the portfolios. In the interisland cable case, RESOLVE wants to build less grid scale solar first 5 years in favor of lower cost and higher quality wind on the neighbor islands. However, given the uncertainty around the cable feasibility and timing, and the potential fleeting opportunity of the tax subsidies, the cost of overbuilding tax subsidized solar early is relatively small and a risk of counting on an uncertain future cable can be quite large. More impactful differences in resource decisions start to occur in 2022. We recommend that these resource choices be analyzed in detail in future planning rounds, with more development of the cost assumptions and operational constraints of the cable options.

9. Letting the model choose to build DGPV beyond 2020 results in lower DGPV buildout than the market DGPV forecast. On Oahu, the decrease of DGPV over the market DGPV forecast results in increased build of grid-scale solar resources, which are less expensive than DGPV on a total resource cost basis. On Maui there are increasing amounts of both grid-scale solar and wind, whereas on Hawai'i the wind resource is sufficiently dominant over the other options that the market forecast DGPV is completely replaced with wind.

10. Companies asked us to assume that all DGPV installed beyond 2020 is fully curtailable. If we remove this assumption, the model builds more battery resources throughout the plan. The cost differences over the high DGPV curtailable case are material and grow over time. Moreover, our modelling assumes that the system operator can operate the system with perfect foresight under normal operating conditions. Under more strenuous, information poor conditions, the operator is going to have to curtail larger quantities of energy than we estimate. If curtailment control is limited, there a possibility that reliability can be jeopardized. We want to highlight the curtailment assumption for all new post 2020 DGPV because we believe that renewable curtailment for all resources is a fundamental renewable integration tool that our modelling assumes and uses to minimize projected costs.

Results from Stakeholders' Cases

11. Ulupono asked us to run a case where LNG costs were higher by 35% to reflect a fuel price hedge against future volatility that would naturally be avoided with investments in renewable resources. The results are similar to those from the No-LNG case, where fuel prices are approximately double those in the LNG scenario per MMBTU. The Companies have an economic incentive to interconnect as much tax advantaged renewable resources as they can before the federal tax incentives expire. Under Internal Revenue Service (IRS) rules, a facility will be considered to satisfy the Continuity Safe Harbor if it is placed in service during a calendar year that is no more than four calendar years after the calendar year in which construction of the facility began[1]. Thus, the Companies have an incentive to begin construction of tax advantaged renewable resources before they are strictly needed as the construction can be completed up to four years later and still allow the facility to receive federal subsidies.

12. Hawaii Gas asked us to run a case using a Hawaii Gas produced LNG price forecast on Oahu Island, with no LNG on the neighbor islands. The LNG price forecast from Hawaii Gas was based on a volume assumption of 0.9 MTPA with a price of $12.32/MMBTU in 2022 (this price, in $2016, represents the "total cost" of LNG import including delivery to power plant; it does not include power plant conversion costs, which are included separately), a high of $13.06/MMBTU in 2030, and decreasing back to $12.66/MMBTU in 2040. The resulting build is similar to the HECO LNG Market DGPV case results, and in the first five years there are effectively no differences in thermal and renewable procurement decisions.

13. Dr. Fripp, on behalf of Ulupono, requested that we include additional solar and wind resources on Oahu by extending the supply estimates produced by NREL. The base

[1] https://www.irs.gov/pub/irs-drop/n-16-31.pdf

cases were limited to 164 MW of onshore wind and 2756 MW of utility scale solar; the increased supply estimates include smaller and potentially higher cost sites and have total resource potentials of 2680 MW of onshore wind and 6583 MW of utility scale solar. We did not have accurate estimates of costs for these sites, but the addition of these new sites increased the early renewable build for wind on Oahu, from 30 MW to 370 MW in 2022, assuming no additional development costs per kWh of output. This increase can be attributed to the higher capacity factors of the best resource tranche relative to the average capacity factor used in the Companies reference case. However, this significantly larger renewable build is still limited by the near-term interconnection limits on the system.

14. Paniolo asked us to substitute their own estimates of performance and costs for 6-hour pumped-storage hydro (PSH) and wind for the input assumptions given to us by the Companies for the base cases. The Paniolo performance characteristics showed higher capacity factors for the wind resource and similar resource costs for both wind and PSH when compared to the Companies assumptions for the same resources. However, the resource cost of PSH remained significantly more expensive than 4-hour batteries. In the Companies base case runs, the PSH is an option but never selected due to its relatively high costs compared to batteries. Paniolo wanted to see the impact on total costs of including their project. To derive this result, we forced the model to take the combination of 30 MW of wind and 30 MW of PSH in 2022, per the Paniolo specifications. As a result, the Paniolo PSH displaces some of the RESOLVE battery build decisions throughout the planning horizon, but at a higher capital cost due to both the increased capacity (30 MW of PSH versus 14 MW batteries in 2022 in the base case) and higher unit cost of the PSH when compared to batteries. The Paniolo sensitivity is approximately 13 percent higher than the Company base case plan.

15. DBEDT requested that we develop a process to use RESOLVE to test the robustness of our findings. DBEDT's main concern was with regard to the proposed 5-year plan and anything that might change in it that was sensitive to long term forecasts of uncertain variables. We discussed the following four uncertain variables in our analysis: fuel price forecasts, renewable price forecasts, storage price forecasts, and the impact of the interisland transmission cable. Because LNG was not being requested in the 5-year plan and RESOLVE did not recommend new thermal resources in the 5-year plan, DBEDT only requested that we look at whether the cable would change the 5-year recommended plan. We confirmed with DBEDT in our follow up call that the copper plate cable case only increased the amount of renewable build on the neighbor islands in the five-year plan. The renewable build on the neighboring islands will already be constrained during the five-year plan by the amount of renewables interconnectable during that time period, thus there will be no difference in renewable build on Maui

and the Big Island. However, we do agree with DBEDT that the cable is a potential game changer for the longer-term plan.

The types of renewable build the model selects do change with the interisland cable. Oahu has reduced grid scale solar build, for example, in the cable case in the first 5 years. We recommend following the individual island case build cases for two reasons. First, there is a substantial level of uncertainty regarding cable feasibility and timing. Second, over the next decade, we don't see a substantial loss of renewable build on Oahu being replaced with low cost renewables on the neighbor islands because of the near-term interconnection and integration constraints.

16. DBEDT also requested a sensitivity on the inclusion of the military units in the reference case. The Marine Corps Base Hawaii (MCBH) at Kaneohe Bay and the Joint Base Pearl Harbor-Hickam (JBPHH) were included as planned resources in the base cases. A sensitivity was run where the model was given the option to purchase those units, but they were not selected in the base thermal build; increased amounts of renewable energy (in the No-LNG cases) and other dispatchable LNG resources (in the LNG cases) were chosen to replace this capacity.

    As we discuss in response to Question 6 below, the RESOLVE model does not investigate detailed contingencies or system security constraints, and there may be reliability and other benefits to keeping these projects online which RESOLVE is not considering. Furthermore, reliance on additional renewables to replace these units is contingent on being able to install and fully integrated those renewables in the near term. Getting the transmission in place to do so is uncertain and MCBH and PBPHH units would increase the flexibility of the system while transitioning to greater reliance on renewables.

17. Finally, we developed the single lowest cost plan for the Consumer Advocate (CA Sensitivity) that did not comply with the RPS and utilized LNG/Market DG. These lowest cost plans were run under both No-LNG and LNG conditions, utilizing the Market DG forecast. In all cases, the plans are less expensive than the individual island Market No-LNG RPS-constrained base cases, but by only a small amount. In the last cost plan on both Maui and Hawaii gets you to nearly a 100 percent RPS compliant portfolio by 2045.

18. Table 2 below shows normalized costs for each individual island's Non-RPS constrained bases.

    Table 3 below shows the portion of annual electricity coming from RPS-eligible sources. Note that in the No-LNG cases a significant portion of electricity is being sourced from renewable resources, even without an RPS constraint, because the economics of renewable sources are favorable.

Table 2. Costs for Consumer Advocate No-RPS constraint cases, normalized with respect to No-LNG Market DGPV cases

Oahu	No-RPS Market DGPV
No-LNG	0.87
LNG	0.84
Maui	**No-RPS Market DGPV**
No-LNG	0.99
LNG	0.80
Hawaii	**No-RPS Market DGPV**
No-LNG	0.98
LNG	0.81

Table 3. Portion of annual electricity from RPS-eligible sources, in Consumer Advocate No-RPS constraint cases.

Oahu	2020	2022	2025	2030	2035	2040	2045
No-LNG	34%	41%	50%	55%	61%	66%	72%
LNG	28%	29%	31%	34%	35%	34%	45%
Maui	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
No-LNG	54%	72%	73%	75%	74%	83%	95%
LNG	45%	64%	63%	65%	63%	63%	67%
Hawaii	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
No-LNG	63%	71%	76%	78%	79%	80%	95%
LNG	63%	76%	78%	80%	79%	80%	76%

Q6. DO YOU HAVE ANY CAVEATS REGARDING YOUR FINDINGS?

A6. Yes, performing the variety of cases analyzed using an optimal expansion planning model required that we use a simplified planning reserve margin (PRM) measure of reliability for plans that require high amounts of variable energy resources, and estimates of operating reserves. We also did not model transmission networks, stability constraints, or contingency requirements. The Companies are supplementing our analysis with modelling using the PLEXOS simulation model and analysis performed by Ascend Analytics to address these limitations. The Companies are also performing system security analyses to determine minimum inertia, fast frequency response, primary frequency response and fault current needed to maintain stable and reliable isolated island grids. However, even the collection of these models does not adequately stress the reliability of each high renewable plan over time.

The assumptions that define each case are necessarily simplifying for several reasons:

- The system operating requirements for reliable service in the future are currently uncertain. Between now and 2045, the technologies at grid scale and behind the meter will change significantly, requiring new operating procedures and reliance on new technologies such as storage for grid services previously met with thermal generation. The assumptions used to define the need for ancillary services in RESOLVE are therefore more certain in early years when the system is still relatively familiar, and less certain in later years when significantly more renewables and other novel technologies are installed. The rate with which the system changes differs by island, depending on the relative economics of different resource options.

- RESOLVE does not include detailed power flow and stability analysis that would consider transmission networks, unit reliability, and contingency measures.

- The computational complexity of capacity expansion and hourly dispatch logic in RESOLVE means that additional detailed transmission network constraints would significantly slow down the model. Furthermore, many of the constraints around reliability are not quantified by a simple formula suitable for modeling. RESOLVE is an appropriate combination of complexity and runtime such that many iterations and sensitivities can be run to determine least cost resource portfolios through to 2045 and inform the more detailed, near term HECO modeling effort.

- RESOLVE does not incorporate the complex contract structures with existing renewable resources. All renewable resources in RESOLVE are assumed to recover their full capital cost over their lifetimes and incur only variable costs per MWh generated.

- The RESOLVE input datasets do not include more detailed generator characteristics such as "black start", maintenance schedule, generator reliability etc.

- RESOLVE can identify when a generator is no longer needed under normal operation conditions according to Companies' reserve constraints. However, without considering the more detailed generator characteristics, power flow implications, and contingency constraints, RESOLVE can only act as a guide to identify candidate units for removal from service. Whether a unit is removed from service is therefore addressed in the Plexos modeling.

Given these limitations of the results, the RESOLVE least cost resource plans act as a guide and starting point for the Company team. Although we believe that our results are unbiased with regard to technology choice and suitable for the economic comparison between the different plans, we recommend that the Companies, working closely with key stakeholders, regulators, and state agencies, continue to refine their long-term planning models and data to incorporate more real world operational constraints. We do not recommend the use of the RESOLVE cases by themselves be used to make permanent plant retirement decisions.

Q7. HOW IS THIS DOCUMENT ORGANIZED?

A7. In Section 2 we describe the overall results of the base case scenarios we were asked to develop for the Companies using the input data and assumptions define by the Companies. Section 3 then lays out the sensitivity case for the base case scenarios. Section 4 describes the sensitivity cases that we put together for third parties who requested and defined them. Finally, an attached appendix contains the input assumptions that were used to define each of the RESOLVE cases described below.

2: COMPANIES BASE CASE

Q8. PLEASE DESCRIBE THE KEY DIFFERENCES IN THE ASSUMPTIONS USED TO DEFINE THE COMPANY BASE CASES.

A8. The base case for each island is the No-LNG option using the "Market" DGPV forecast for installed DGPV. All installed DGPV through 2020 are assumed to be uncontrollable and uncurtailable, whereas all DGPV resources installed beyond 2020 are allowed to be economically curtailed if required. This is a critical assumption that allows us to minimize the costs of these high renewable energy cases.

Q9. PLEASE DESCRIBE THE RESOLVE MODEL RESULTS FOR EACH OF THE BASE CASES.

A9. Capacity graphs show installed capacities aggregated by resource type. The capacities shown in the graph are resources which the model utilizes for either energy or to meet PRM purposes. There are some resources which the model does not find necessary to use under normal operating conditions and, while on the system, are not displayed on the utilized capacity graphs. These resources are potential candidates for deactivation and further study for potential retirement if found to be unnecessary for system needs in the more detailed modeling performed by the Companies. The breakdown between utilized capacity and un-utilized capacity can be seen in the Appendix. As addressed in Q6 please note that normal operating conditions, while including contingency reserve and operating reserve constraints as specified by the Companies, are not meant to encapsulate system security and contingency conditions, and therefore the RESOLVE results should not be taken to mean that a resource whose capacity is not being utilized should be retired. For the main takeaways from these base case results see Q10.

Figure 1. Utilized installed capacity for Oahu No-LNG Market DGPV case

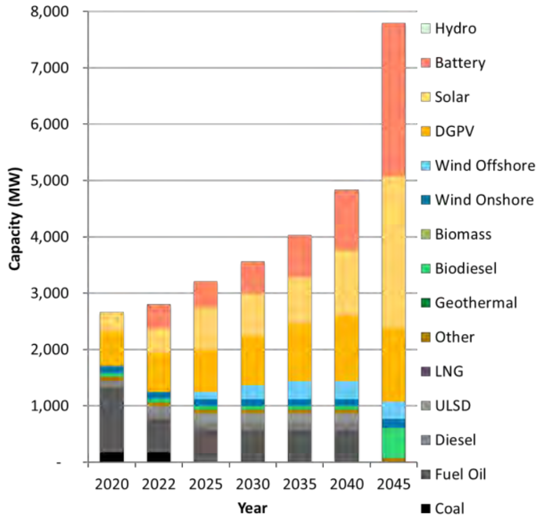


Figure 2. Utilized installed capacity for Maui No-LNG Market DGPV case

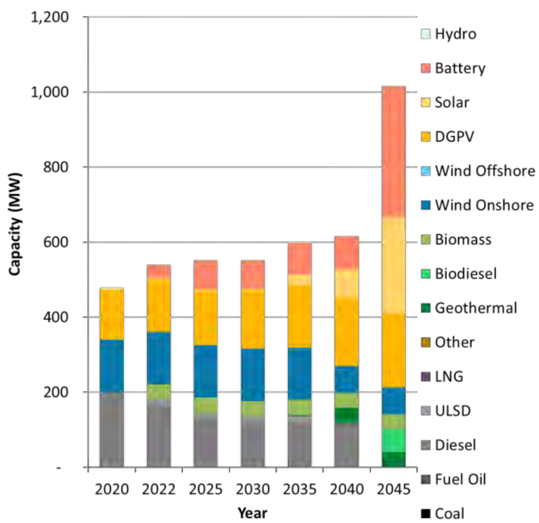
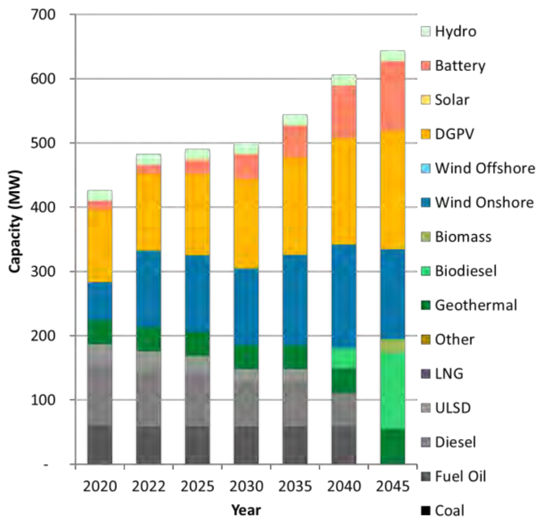


Figure 3. Utilized installed capacity for Hawai'i Island No-LNG Market DGPV case



Q10. WHICH OF YOUR MAIN FINDINGS DID YOU REACH BASED ON YOUR BASE CASE ANALYSIS AND PLEASE HIGHLIGHT THE RESULTS THAT YOU RELIED ON TO SUPPORT THOSE FINDINGS?

A10. On all islands, during the first five years (through 2022), RESOLVE moves aggressively to build renewable resources. This is especially pronounced on Hawai'i Island and Maui, where there is a markedly increased amount of wind built in 2022. RESOLVE is moving to take advantage of tax-credited renewable resources early, but is constrained in its ability to do so by interconnection constraints (as stated in Q5 above, the interconnection limits modeled here are maximum additional renewable resources by 2020 of 130MW of wind for Maui, 20MW of wind for Hawaii, and 300MW of solar for Oahu).

On all islands, there are no new thermal resources selected by RESOLVE beyond those already planned to be in service. On Oahu in particular this result is true assuming that the military units (MCBH and JBPHH) are planned to be in place by 2022 and 2025.

On all islands, the value of renewable resources relative to thermal resources rises over the study horizon, so the conventional thermal fleet size decreases. There is a slight uptick on Hawai'i in 2045 as there is more biodiesel capacity in 2040 than conventional oil capacity in 2040. This is because as there are some underutilized resources which are converted to biodiesel in 2045. These biodiesel resources are used primarily for capacity to meet PRM; the majority of RPS-eligible energy comes from wind, with DGPV and geothermal sources filling in the rest.

Oahu and Maui see a "hockey stick" like build in which the last year sees a large amount of energy storage built. This large build late build is due to: 1) the large increase in RPS from 70% in 2040 to 100% in 2045; 2) the high cost of biodiesel (nearly 2x the cost of conventional diesel); and 3) the steeper decrease in battery costs relative to the pace of cost changes for other resources. Nevertheless, batteries (representative of energy storage and other demand response more broadly that can provide the same services) are cost effective as early as 2020 on Hawai'i and 2022 on Maui and Oahu.

3: COMPANIES SENSITIVITIES

Q11. PLEASE DESCRIBE THE INPUT ASSUMPTIONS USED TO DEFINE THE COMPANIES SENSITIVITY CASES

A11. In addition to the base case, the Companies identified several sensitivity cases. The list of the Companies-defined sensitivities are defined below, with more details in each case results section.

1. No-LNG with "High" DGPV Forecast: Use the "High" DGPV forecast on each island instead of the "Market" DGPV forecast.

2. LNG with "Market" DGPV Forecast: Allow the model to procure LNG resources after 2022, with the option of converting various existing thermal generators. Cost data for this conversion is provided by the Companies. The LNG fuel is available starting in 2022, but not available in 2045.

3. LNG with "High" DGPV Forecast: Similar to the LNG with "Market" DGPV forecast, but with the "High" DGPV forecast on each island.

4. DGPV as an endogenous choice: Model is given the option of procuring DGPV resources, with cost data for the DGPV resources provided by the Companies. The DGPV installed through 2020 is assumed to be still on the system.

5. DGPV as uncurtailable: Model is run using No-LNG "High" DGPV forecast on each island, but all DGPV installed after 2020 are not assumed to be curtailable.

6. Copperplate with "Market" DGPV Forecast: Assume all islands are connected with infinite capacity, infinite reliability transmission cables.

Q12. PLEASE DESCRIBE THE RESOLVE MODEL RESULTS FOR EACH OF THE SENSITIVITY CASES

A12. For each sensitivity case, we present a capacity chart and a normalized cost table with entries for each evaluation year.

Capacity graphs, as described in Q9, show utilized installed capacities for each case, aggregated by resource type.

Cost tables compare the cost of the cases relative to the base cases as defined in Q9: No-LNG Market DGPV forecast cases. Values greater than 1.00 signify the cost for the sensitivity case in question is greater than that of the No-LNG Market DGPV case. The costs reported by RESOLVE and summarized in these tables are for the cumulative incremental resource build and the cumulative total system operating and O&M costs up to the year in question. Costs are reported on a total resource cost basis. The total cost at the end of the time horizon of the base case under this definition is $10.6 billion on Oahu, $1.7 billion on Maui, and $1.1 billion on the Big Island.

1. No-LNG with High DGPV Forecasts

The No-LNG "High" DGPV cases were run using the same input assumptions as each of the islands' base cases, with the substitution of the "High" DGPV forecast instead of the "Market" DGPV forecast.

On Oahu, the difference between this case and the base case is mostly cost, as the more expensive DGPV resources are built instead of lower cost grid-scale solar resources. Table 4 below, for example, shows that the High DGPV case has higher cost renewables by 12% and higher costs storage by 3% by 2045 compared to the No-LNG Market DGPV case. The total cost of this case is 5% higher than the market DGPV case by 2045.

On the neighbor islands, the mix of resources changes more significantly. On Maui, the increased DGPV forecast results in much higher capital costs of renewable energy (157%) and decreased grid-scale solar and grid-scale wind build. The Hawaii case has even more DGPV in the high case, which shows an even higher renewable energy capital cost (189% for the capital cost of renewable energy) compared to grid-scale wind in the Hawaii base case.

On all islands the High DGPV cases have a higher total resource cost than the Market DGPV cases, which is consistent when the higher cost and lower capacity factors of DGPV resources compared to the alternative grid-scale renewable resources.

Oahu Results

Figure 4. Utilized installed capacity for Oahu No-LNG High DGPV case

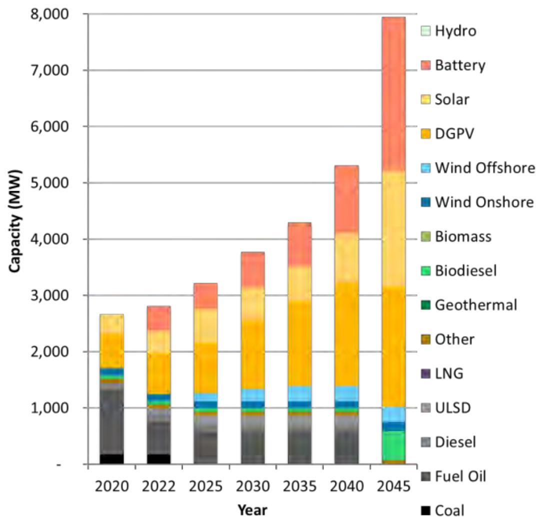


Table 4. Cumulative total resource cost for the Oahu No-LNG High DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.00	1.00	0.99	0.99	0.99	1.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.02	1.06	1.08	1.10	1.14	1.12
Battery							
Capital	0.00	1.00	1.00	1.02	1.03	1.04	1.03
Total	1.00	1.00	1.01	1.02	1.03	1.04	***1.05***

Maui Results

Figure 5. Utilized installed capacity for Maui No-LNG High DGPV case

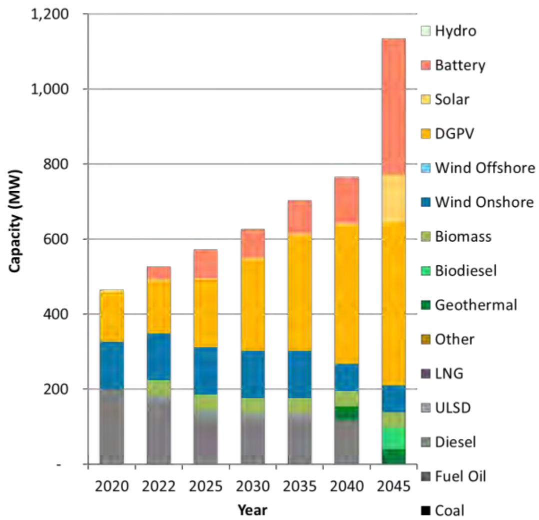


Table 5. Cumulative total resource cost for the Maui No-LNG High DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.06	1.06	1.04	1.01	1.00	1.00	0.99
Fixed	1.00	1.00	1.00	1.00	0.99	0.99	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.81	0.82	0.98	1.20	1.38	1.57	1.57
Battery							
Capital	0.00	0.94	0.98	0.99	0.99	1.03	1.04
Total	1.01	1.00	1.01	1.03	1.06	1.09	***1.10***

Hawai'i Island Results

Figure 6. Utilized installed capacity for Hawai'i Island No-LNG High DGPV case

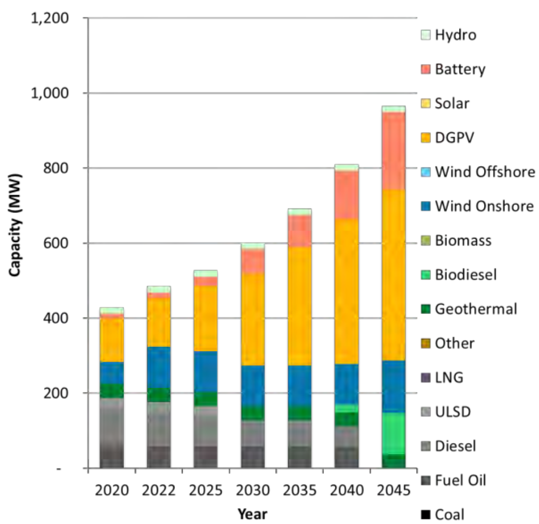


Table 6. Cumulative total resource cost for the Hawai'i Island No-LNG High DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	0.99	1.01	0.99	0.96	0.95	0.94	0.93
Fixed	1.01	1.00	1.00	0.98	0.97	0.97	0.72
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.01	1.20	1.43	1.61	1.75	1.89
Battery							
Capital	0.97	0.97	1.05	1.24	1.34	1.39	1.50
Total	1.00	1.01	1.03	1.08	1.12	1.17	***1.18***

2. LNG with Market DGPV Forecasts

The LNG "Market" DGPV cases were run allowing the model to procure LNG resources. We give the model the option of converting various existing generators or maintaining the fuel oil versions of those generators, with cost data for this conversion provided by the Companies. The choice of LNG conversion occurs in 2022, the COD year for the LNG import hubs and when LNG is available as a fuel option.

On all islands, no new LNG power plants are built, but a number of existing large generators are fuel-switched; on Maui and Hawai'i these are the large dual train combined cycle plants - Maalaea and Keahole, respectively. On Oahu, the LNG converted plants include the Kalaeloa Partners (KPLP) plant, and some amount of the newer Kahe steam turbines. The precise units which are converted should be decided on the basis of conversion costs, expected reliability, and system security constraints.

The value of the LNG resource to each island is dependent in part on the cost of the LNG fixed infrastructure costs. The cost of the plant unit conversions is born by the island in question, but there is some uncertainty in the allocation of the cost of the LNG import hub and ISO container infrastructure to each island. As a first pass to use in the RESOLVE cases, we have allocated all of the cost of the LNG import fixed infrastructure pieces to Oahu, as Oahu has the largest LNG demand and the greatest absolute cost reduction when LNG is available. However, this means that the relative benefits on Oahu are lower than they would be if the cost of the hub was split among islands; similarly, the relative benefits of LNG on Maui and Hawai'i are greater than they would be if the cost of the hub was apportioned to those islands as well. Thus, the relative cost savings of an LNG import hub listed below are a lower bound on Oahu and an upper bound on Maui and Hawai'i.

Another cost difference worth highlighting is that of the thermal fixed costs. The thermal fixed costs on Oahu are quite large, ranging from 3.27 (see table below; note these are relative costs) in 2022 to 5.76 in 2045. The thermal fixed cost is the fixed cost of thermal resources in the LNG case normalized to the fixed cost of the thermal resources in the Non-LNG case. The LNG case thermal resources includes the cost of the LNG fixed infrastructure, which is a cost of nearly $300 million annually. In addition to this, the thermal fixed costs include the conversion cost of the individual power plants on Oahu. Finally, the fixed cost of the No-LNG cases includes only the avoidable fixed O&M costs for the existing thermal resources; the RESOLVE framework includes incremental resource costs only, so if there are any fixed sunk costs which cannot be avoided by making different decisions, then those costs are not included in the fixed cost as described below.

As various thermal resources retire the No-LNG case fixed thermal cost declines, whereas in the LNG case the annualized cost of the LNG hub and the annualized cost of the LNG conversion stays constant for the lifetime of the resources (20 years). This means the LNG thermal fixed cost stays nearly constant, but when calculating the ratio cost difference between cases, it is divided by a No-LNG case base case cost that is decreasing over time; this results in the relative cost of the LNG thermal fixed cost component appear to increase over time. Thus, because of a combination of (1) large LNG hub fixed infrastructure costs; (2) constant annualized cost of LNG hub and conversion cost; (3) low fixed costs for continuing non-LNG resources; and (4) the

RESOLVE optimization framework which minimizes the incremental total resource costs, the thermal fixed infrastructure cost in the Oahu LNG case is large and increasing in comparison to the No-LNG case.

By contrast, the renewables and thermal variable cost components in the Oahu LNG cost table are both below one. However, the amount of renewable resources and the amount of fuel burn are so large that these cost components more than out-weigh the increased cost of the thermal fixed resource cost component, so that the total relative resource cost for the LNG case is significantly below that of the Non-LNG case. For all three islands, the LNG case is substantially lower in total cost than the Non-LNG base case.

Oahu Results

Figure 7. Utilized installed capacity for Oahu LNG Market DGPV case

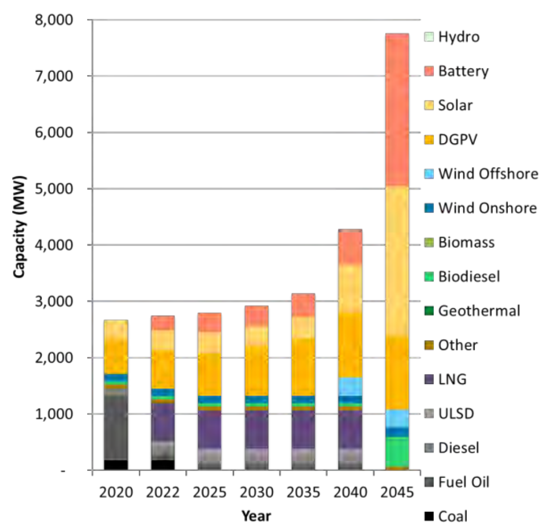


Table 7. Cumulative total resource cost for the Oahu LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	0.81	0.73	0.70	0.68	0.65	0.67
Fixed	1.00	3.27	4.79	5.63	6.04	6.27	5.76
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.90	0.58	0.48	0.46	0.54	0.67
Battery							
Capital	0.00	0.60	0.69	0.67	0.66	0.64	0.76
Total	1.00	1.01	0.97	0.94	0.91	0.91	***0.92***

Maui Results

Figure 8. Utilized installed capacity for Maui LNG Market DGPV case

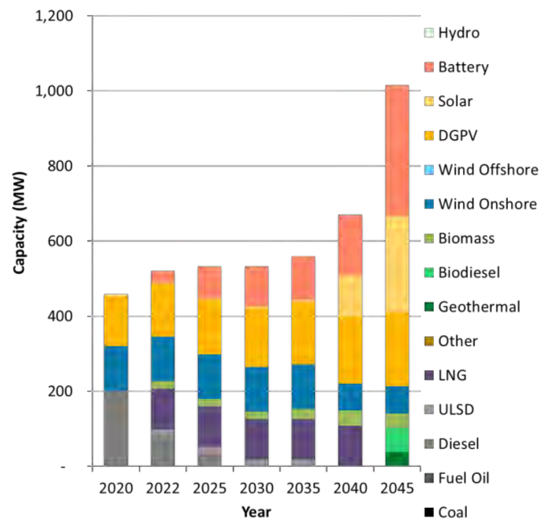


Table 8. Cumulative total resource cost for the Maui LNG Market DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.10	0.97	0.89	0.82	0.77	0.75	0.76
Fixed	1.00	0.99	0.97	0.93	0.92	0.86	0.89
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.70	0.72	0.73	0.74	0.74	0.78	0.84
Battery							
Capital	0.00	0.87	1.04	1.16	1.19	1.25	1.17
Total	1.02	0.94	0.89	0.86	0.83	0.82	***0.85***

Hawai'i Island Results

Figure 9. Utilized installed capacity for Hawai'i Island LNG Market DGPV case

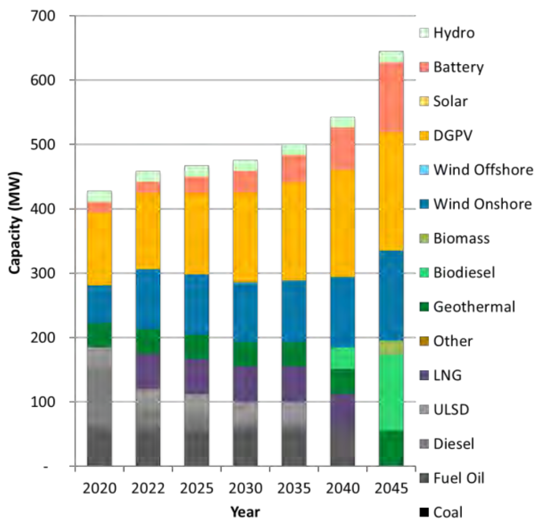


Table 9. Cumulative total resource cost for the Hawai'i Island LNG Market DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	0.90	0.82	0.76	0.73	0.71	0.73
Fixed	0.97	1.15	1.24	1.29	1.32	1.33	1.23
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.78	0.76	0.76	0.75	0.75	0.80
Battery							
Capital	1.19	1.19	1.18	1.09	1.04	1.00	1.00
Total	1.00	0.93	0.89	0.86	0.83	0.82	***0.85***

3. LNG with High DGPV Forecasts

The LNG with High DGPV forecast shows decreased solar and grid-scale renewable sources on all islands, which is consistent with the No-LNG High DGPV case. In addition, there are fewer batteries before 2040 compared to the No-LNG cases, as the LNG resources can be used to provide power during low renewable output hours. However, the final build of 2045 is similar to that of the No-LNG High DGPV forecast, as all islands have a large battery build and biodiesel conversion of various existing resources.

Oahu Results

Figure 10. Utilized installed capacity for Oahu LNG High DGPV case

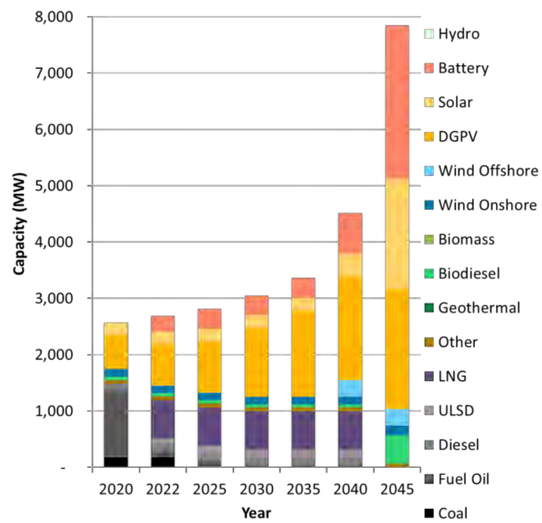


Table 10. Cumulative total resource cost for the Oahu LNG High DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.05	0.85	0.76	0.72	0.69	0.66	0.68
Fixed	1.04	3.29	4.81	5.63	6.03	6.26	5.74
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.61	0.65	0.51	0.51	0.56	0.67	0.79
Battery							
Capital	0.00	0.67	0.72	0.70	0.66	0.66	0.77
Total	1.00	1.02	0.98	0.96	0.94	0.96	***0.97***

Maui Results

Figure 11. Utilized installed capacity for Maui LNG High DGPV case

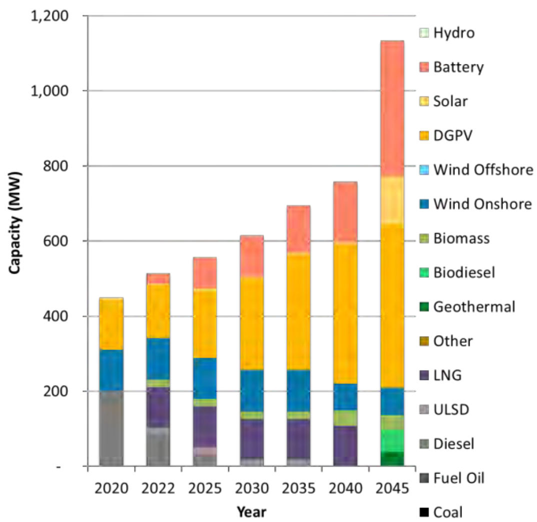


Table 11. Cumulative total resource cost for the Maui LNG High DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.14	1.01	0.91	0.82	0.76	0.74	0.75
Fixed	1.00	1.01	0.98	0.93	0.91	0.85	0.88
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.58	0.60	0.77	1.00	1.20	1.41	1.45
Battery							
Capital	0.00	0.76	1.00	1.14	1.19	1.26	1.19
Total	1.02	0.94	0.91	0.90	0.90	0.91	***0.95***

Hawai'i Island Results

Figure 12. Utilized installed capacity for Hawai'i Island LNG High DGPV case

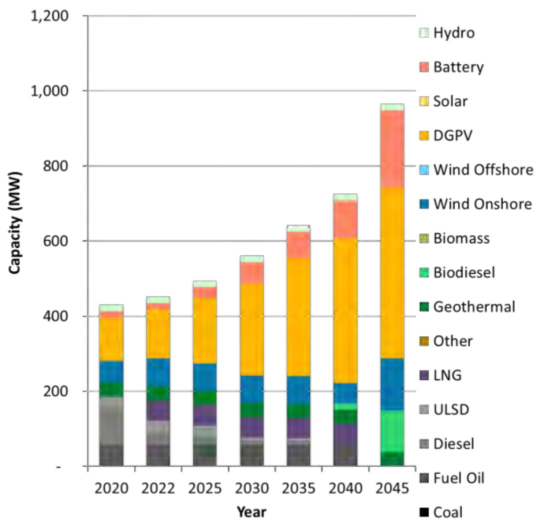


Table 12. Cumulative total resource cost for the Hawai'i Island LNG High DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.99	0.93	0.85	0.77	0.73	0.70	0.70
Fixed	0.97	1.15	1.24	1.27	1.29	1.30	0.94
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.72	0.86	1.10	1.30	1.45	1.65
Battery							
Capital	1.17	1.17	1.24	1.32	1.34	1.33	1.45
Total	0.99	0.94	0.92	0.94	0.97	1.00	***1.04***

4. DGPV as Endogenous Model Choice

In the following cases, the forecasted DGPV build by 2020 is left as is, but all DGPV beyond 2020 is left as a model decision. On each island, there is no DGPV resource built after 2020, as grid-scale renewable resources are cheaper and higher quality than the DGPV resources. On Oahu and Maui, the difference is largely within resource category, as DGPV is replaced with more solar. On Hawai'i Island, the wind resource is of sufficient capacity factor that the DGPV is replaced by wind capacity instead of grid-scale solar capacity.

Oahu Results

Figure 13. Utilized installed capacity for Oahu No-LNG Endogenous DGPV case

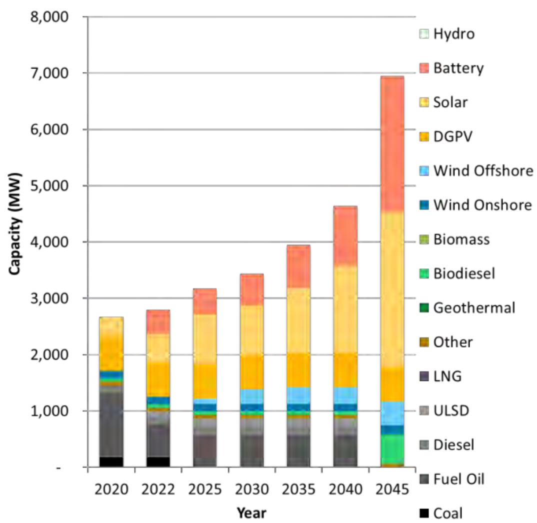


Table 13. Cumulative total resource cost for the Oahu No-LNG Endogenous DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.00	1.01	1.01	1.01	1.01	1.03
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.97	0.94	0.94	0.91	0.88	0.89
Battery							
Capital	0.00	1.00	1.00	0.99	1.00	1.00	0.96
Total	1.00	0.99	0.99	0.99	0.98	0.97	***0.97***

Maui Results

Figure 14. Utilized installed capacity for Maui No-LNG Endogenous DGPV case

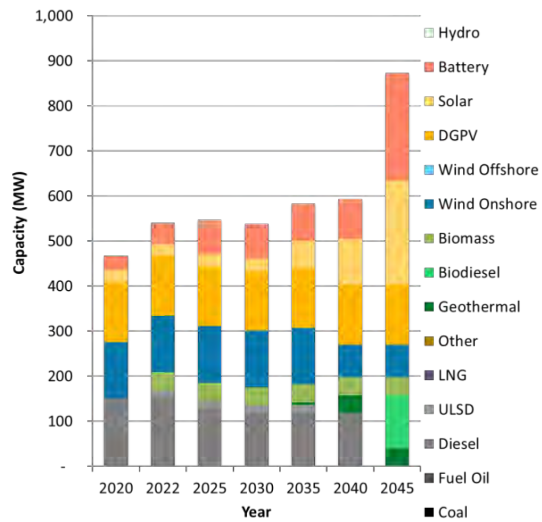


Table 14. Cumulative total resource cost for the Maui No-LNG Endogenous DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	0.99	0.99	0.99	1.00	1.00	1.00	1.13
Fixed	0.64	0.82	0.89	0.91	0.94	0.95	0.95
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.04	0.99	0.96	0.91	0.88	0.84	0.80
Battery							
Capital	*Div by 0*	3.00	1.63	1.42	1.29	1.26	1.06
Total	0.97	0.98	0.98	0.98	0.98	0.97	***1.00***

Hawai'i Island Results

Figure 15. Utilized installed capacity for Hawai'i Island No-LNG Endogenous DGPV case

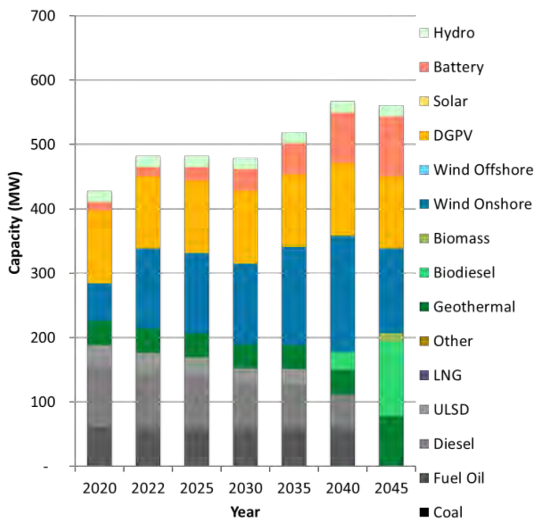


Table 15. Cumulative total resource cost for the Hawai'i Island No-LNG Endogenous DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	0.99	1.00	1.00	1.00	1.01	0.99
Fixed	1.00	1.00	1.00	1.01	1.01	1.01	1.15
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.98	0.94	0.90	0.86	0.82	0.77
Battery							
Capital	0.99	0.99	0.99	0.96	0.96	0.96	0.94
Total	1.00	0.99	0.99	0.98	0.97	0.96	***0.96***

5. Uncurtailable High DGPV

In the base case, we assume that all DGPV installed after 2020 is controllable. Curtailing DGPV in future years is a useful and valuable integration mechanism that reduces system costs. To investigate how valuable curtailment of DGPV is, we ran the bookend case on DGPV controllability, assuming all DGPV installed over the model time horizon is uncontrollable. This increases the amount of batteries built over the base case. On Oahu, the table below shows the relative costs of resources selected versus the base case. By 2045, an additional 19% cumulative investment in batteries is made over the base case to integrate the uncontrolled DGPV. Overall, the cost of the uncontrolled DGPV case on Oahu is 6% higher in 2045 than the base case. Similarly, we see significantly higher battery builds on Maui and Hawai'i Island, with increases of 9% and 19% in total cumulative cost by 2045, respectively.

Oahu Results

Figure 16. Utilized installed capacity for Oahu No-LNG Uncurtailable High DGPV case

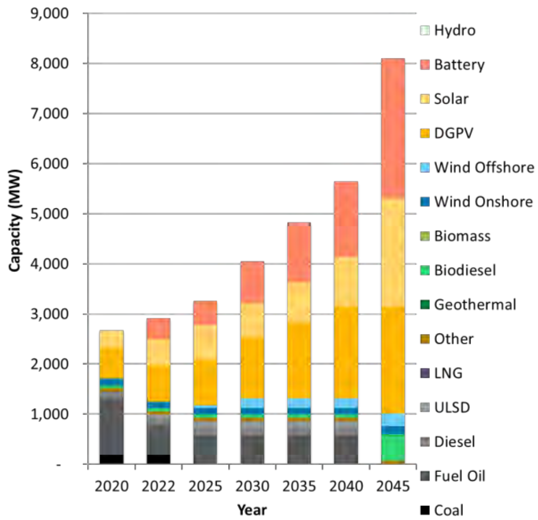


Table 16. Cumulative total resource cost for the Oahu No-LNG Uncurtailable High DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	0.98	1.01	1.00	1.00	1.00	1.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.14	1.02	1.06	1.08	1.12	1.11
Battery							
Capital	0.00	1.00	1.03	1.16	1.23	1.26	1.19
Total	1.00	1.00	1.02	1.03	1.04	1.06	***1.06***

Maui Results

Figure 17. Utilized installed capacity for Maui No-LNG Uncurtailable High DGPV case

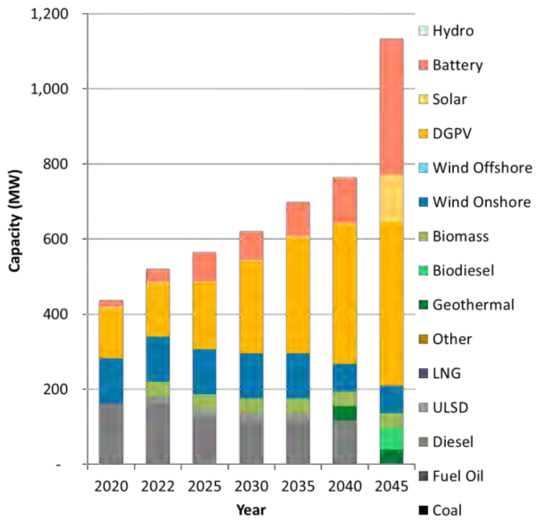


Table 17. Cumulative total resource cost for the Maui No-LNG Uncurtailable High DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource cost						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.08	1.08	1.06	1.03	1.02	1.01	1.01
Fixed	0.72	0.88	0.92	0.94	0.94	0.94	0.95
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.72	0.74	0.90	1.12	1.31	1.50	1.52
Battery							
Capital	*Div by 0*	1.95	1.30	1.19	1.14	1.16	1.13
Total	0.97	0.98	1.00	1.03	1.05	1.08	***1.09***

Hawai'i Results

Figure 18. Utilized installed capacity for Hawai'i Island Uncurtailable High DGPV case

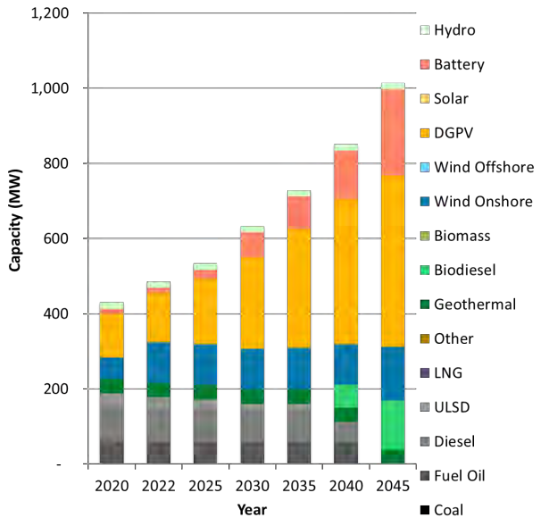


Table 18. Cumulative total resource cost for the Hawai'i No-LNG Uncurtailable High DGPV case (relative to Hawai'i No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.01	1.00	0.97	0.95	0.94	0.93
Fixed	1.01	1.00	1.00	1.01	1.01	1.01	0.75
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.02	1.20	1.43	1.61	1.76	1.90
Battery							
Capital	0.97	0.97	1.02	1.21	1.32	1.37	1.54
Total	1.00	1.01	1.04	1.08	1.13	1.18	***1.19***

6. Copperplate with Market DGPV Forecasts

The copperplate results show significant cost differences and build differences as compared to the individual island cases. There is a large increase in Hawai'i Island wind build, and a small increase in Maui solar, whereas the Oahu renewable build sees a large reduction. The thermal fleet capacity does not change significantly compared to the sum of the individual island cases, but in later years much of this thermal fleet is used for capacity with only the most efficient units across islands being dispatched for energy purposes.

The total cost saving across all islands is roughly $3 billion in present value 2016 dollars. This cost difference is an approximate upper bound value and more detailed scoping should be done to investigate both the engineering feasibility of building the cable and the engineering and siting feasibility of the large grid-scale renewable resource build, which RESOLVE assumes is the individual island base case result in absence of the Copperplate case.

Figure 19. Utilized installed capacity for Copperplate No-LNG Market DGPV case

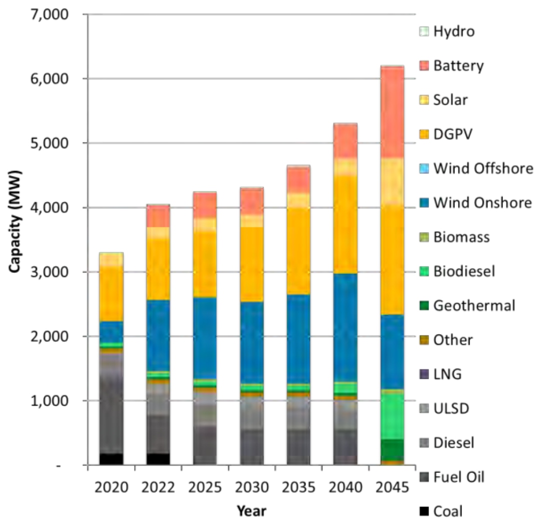


Table 19. Cumulative total resource cost for the Copperplate No-LNG Market DGPV case (relative to sum of individual island No-LNG Market DGPV case costs)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.78	0.80	0.81	0.81	0.80	0.80	0.80
Fixed	0.62	0.53	0.49	0.47	0.46	0.44	0.40
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.74	0.73	0.80	0.84	0.85	0.85	0.86
Battery							
Capital	0.00	0.85	0.84	0.84	0.84	0.85	0.85
Total	0.75	0.76	0.77	0.78	0.79	0.79	***0.79***

4: KEY STAKEHOLDER DEFINED CASES

Q14. PLEASE DESCRIBE THE STAKEHOLDER DEFINED INPUT ASSUMPTIONS USED TO DEFINE EACH CASE

A14. Key stakeholders defined six sensitivity cases for E3 to run through the RESOLVE model to compare against the results of the Company-defined cases. Each key stakeholder and the input assumptions used to alter the Company defined base cases are outlined below.

1. Ulupono: Increase all fuel costs by 35% above the base assumptions on all islands, to account for the hedging value provided by renewable resource against volatile future fuel prices. All other system assumptions were held constant.

2. Hawaii Gas: Hawaii Gas provided an alternate LNG fuel pricing structure from the one developed by the Companies. This sensitivity case only applies to O'ahu, as Hawaii Gas' proposal only includes delivery of LNG to O'ahu.

3. Fripp/Ulupono/Blue Planet: On behalf of Ulupono and Blue Planet, Dr. Fripp provided increased renewable technical potentials on O'ahu from resources of lower quality than the resources identified in NREL's study. Further, Dr. Fripp provided a methodology for adjusting the hourly output profiles that the Companies have provided to E3 to model more granular capacity factors of both higher and lower quality resources than the single category of shapes used in the NREL-sourced data.

4. Paniolo: Paniolo Power provided alternate capital cost information for onshore wind on Hawai'i Island. The capital cost forecasts for pumped-storage hydro was the same as provided by the Companies. The only differences in pumped-storage hydro characteristics captured in RESOLVE are:

1) fixed O&M costs ($28/kW-yr provided by Paniolo vs. $30/kW-yr provided by the Companies), and

2) higher roundtrip efficiency of 85% instead of the 80% provided by the Companies.

In this sensitivity case, E3 paired 30 MW of onshore wind with 30 MW of pumped-storage hydro. Because Paniolo did not provide an alternate hourly profile for its wind unit performance, E3 used the same hourly profiles provided by the Companies to model the paired Paniolo project.

Table 20. Paniolo PSH capital costs

Year	Capital Cost (2016 $/kW)
2020	$2,295
2022	$2,224
2025	$2,117
2030	$1,938
2035	$1,868
2040	$1,798
2045	$1,728

5. Consumer Advocate No LNG: The Consumer Advocate asked E3 to use RESOLVE to test the impact of not meeting the state's Renewable Portfolio Standard as part of its long-term plan, with the goal of estimating how different a least-cost portfolio might look from one that meets the state's clean energy goals.

To run this sensitivity, the RPS target in each study year was removed, such that RESOLVE could choose the least-cost portfolio to meet energy and capacity needs. Some minor input assumptions were also changed, such as allowing the AES coal plant on Oahu to continue beyond 2022.

5. Consumer Advocate LNG: Using similar input assumption as the Consumer Advocate No LNG case, E3 ran a case where the LNG fuel forecast was extended through 2045 to estimate how LNG would affect the least-cost portfolio.

6. DBEDT: DBEDT asked E3 to run a case in which the military power units on Oahu (MCBH and JBPHH) are not planned, but the model is given the option of procuring resources with similar cost and performance characteristics.

Q15. PLEASE DESCRIBE THE RESOLVE MODEL RESULTS FOR EACH OF THE THIRD PARTY DEFINED CASES

A15. Capacity graphs and cost tables, as described in Q9 and Q10, show utilized installed capacities and the cost of the cases relative to the base cases as defined in Q9: No-LNG Market DGPV forecast cases.

1. Ulupono Fuel Hedge Cases

Ulupono fuel hedge case results in little difference as compared to the base case no-LNG. The model chooses to maximize renewable build during the first five-year period and is constrained more by transmission and operations than by economics. During the middle years, each island adds steadily more renewable capacity. The final build is very similar, the difference being that renewable sources are built a few years earlier. For example, on Oahu offshore wind sources are built in 2020 and 2022, whereas in the base case they are not built until later years.

From a renewable energy perspective, the fuel hedge cases show that considering the hedge value of renewables on each island further increases the amount of energy from variable resources above the fraction generated in the No-LNG base case. The effect is relatively small on Maui and the Big Island because renewables are already very competitive against thermal generation prior to the fuel price hedge on these islands. Sales from renewables increase significantly on Oahu, however, because of the lower quality/higher cost renewable resource options. The increase in fuel price in the hedge scenario improves the competitiveness of renewables such that it is economical to procure significantly above RPS levels.

In the cost tables below we show the fuel price hedge as an actual cost, making these scenarios appear to be substantially more costly than the base case. If the hedge is not used as an actual cost, but only as a planning assumption, then the thermal variable cost increases shown in the tables below would not exist (they would be actually lower than 1 because there is less fuel burn due to the higher renewable build) and this plan would only be slightly higher cost than the base case on Oahu and nearly close to the base case on the neighbor islands.

Table 21. Portion of annual electricity from RPS-eligible sources in Ulupono fuel hedge cases compared to Company cases.

Oahu	2020	2022	2025	2030	2035	2040	2045
LNG Base	33%	35%	37%	40%	41%	70%	100%
No-LNG Base	33%	37%	55%	65%	71%	75%	100%
No-LNG fuel hedge	43%	53%	74%	79%	81%	85%	100%
Maui	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
LNG Base	49%	61%	61%	63%	64%	70%	100%
No-LNG Base	54%	75%	74%	76%	77%	83%	100%
No-LNG fuel hedge	57%	77%	79%	81%	85%	87%	100%
Hawaii	**2020**	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
LNG Base	63%	76%	78%	80%	79%	80%	100%
No-LNG Base	63%	82%	83%	85%	87%	88%	100%
No-LNG fuel hedge	71%	86%	87%	88%	90%	90%	100%

Oahu Results

Figure 20. Oahu No-LNG Market DGPV Ulupono fuel hedge utilized capacity results

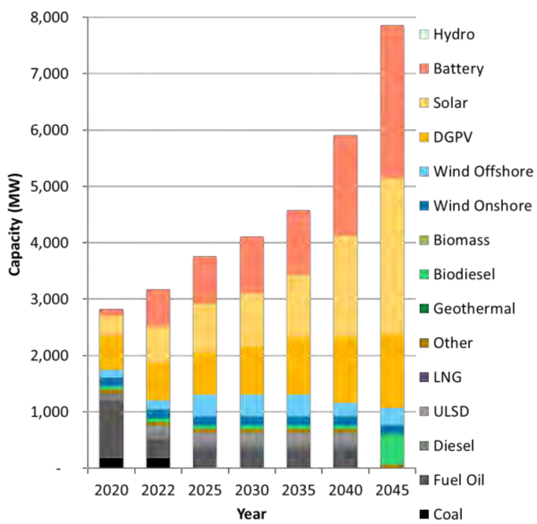


Table 22. Cumulative total resource cost for the Oahu No-LNG Market DGPV Ulupono fuel hedge case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.09	1.01	0.92	0.90	0.89	0.89	0.90
Fixed	0.86	0.80	0.76	0.74	0.73	0.72	0.75
Renewables							

Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	2.67	2.62	2.15	1.83	1.68	1.57	1.41
Battery							
Capital	*Div by 0*	2.04	1.91	1.86	1.77	1.76	1.50
Total	1.27	1.24	1.21	1.19	1.18	1.16	***1.14***

Maui Results

Figure 21. Maui No-LNG Market DGPV Ulupono fuel hedge utilized capacity results

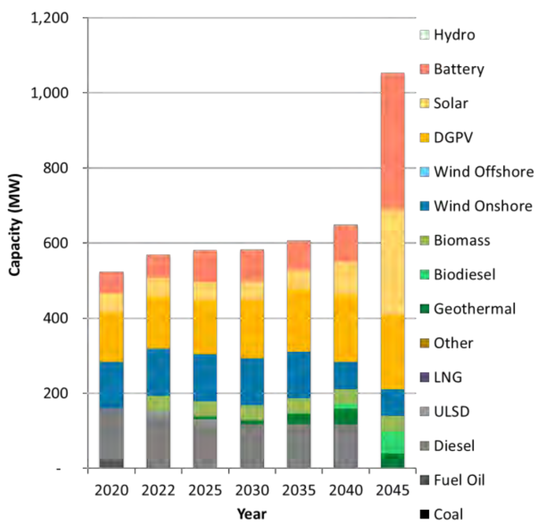


Table 23. Cumulative total resource cost for the Maui No-LNG Market DGPV Ulupono fuel hedge case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.36	1.31	1.26	1.22	1.18	1.18	1.17
Fixed	0.67	0.80	0.92	0.98	1.06	1.06	1.04
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.29	1.28	1.27	1.26	1.21	1.19	1.16
Battery							
Capital	*Div by 0*	4.84	2.28	1.88	1.63	1.58	1.40
Total	1.29	1.22	1.20	1.18	1.17	1.16	***1.14***

Hawai'i Island Results

Figure 22. Hawai'i Island No-LNG Market DGPV Ulupono fuel hedge utilized capacity results

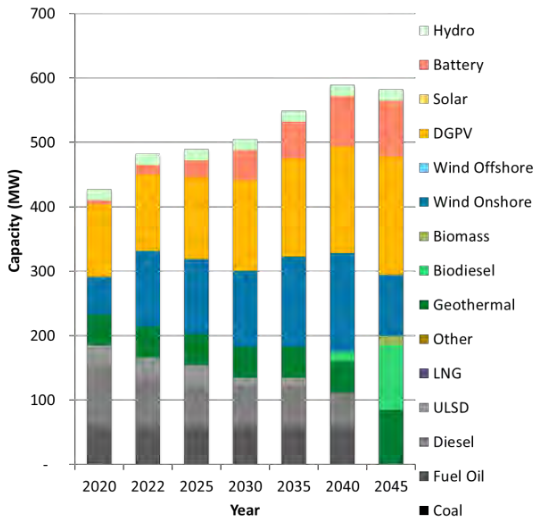


Table 24. Cumulative total resource cost for the Hawai'i Island No-LNG Market DGPV Ulupono fuel hedge case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.13	1.13	1.13	1.13	1.13	1.14	1.11
Fixed	1.78	1.78	1.78	1.79	1.79	1.80	1.74
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.98	0.98	0.98	0.99	0.98	0.93
Battery							
Capital	0.45	0.66	0.85	0.96	1.02	1.01	0.96
Total	1.19	1.19	1.19	1.19	1.19	1.18	***1.16***

2. Hawaii Gas Cases for Oahu

The Hawaii Gas case looks very similar to that of the base LNG case on Hawaii. The Hawaii Gas proposal is less expensive than the base LNG proposal on Oahu, but the actual difference is slightly smaller than the difference portrayed here, as the HECO LNG proposal gives Oahu responsibility for all hub import costs for all three islands as described above. The Hawaii Gas proposal results in LNG units being converted, but no new thermal resources being built during the early years. The renewable build is pushed to later years, but once again the final build in 2045 is similar to the base case build.

Oahu Results

Figure 23. Oahu Hawaii Gas LNG Market DGPV utilized capacity results

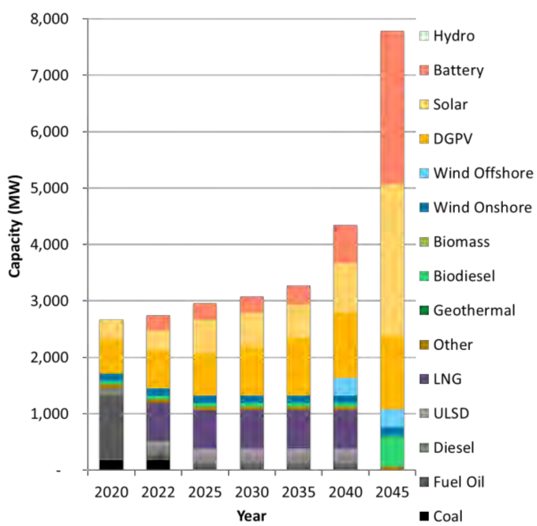


Table 25. Cumulative total resource cost for the Oahu Hawaii Gas LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Thermal							
Variable	1.00	0.92	0.91	0.92	0.93	0.90	0.90
Fixed	1.00	1.44	1.73	1.89	1.97	2.02	1.92
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.90	0.70	0.61	0.58	0.63	0.74
Battery							
Capital	0.00	0.61	0.62	0.58	0.56	0.56	0.71
Total	1.00	0.95	0.91	0.88	0.85	0.85	***0.87***

3. Fripp/Ulupono/Blue Planet Enhanced Renewable Potentials on Oahu Cases

The main difference to note in the enhanced renewables potential case is the large increase in onshore wind capacity. The previous new onshore wind potential was only 30 MW (incremental to wind online by 2020), whereas now there are more than 2000 MW of potential capacity. The model does not build to the maximum onshore potential, but it does build close to 500 MW of new onshore wind resource. Once again, while these results are indicative of the kinds of renewable build Oahu might expect to build, we expect that the actual build will be contingent on the kinds of real world resources and costs which are received during an RFO.

Oahu Results

Figure 24. Enhanced renewable potential case No-LNG Market DGPV utilized capacity results

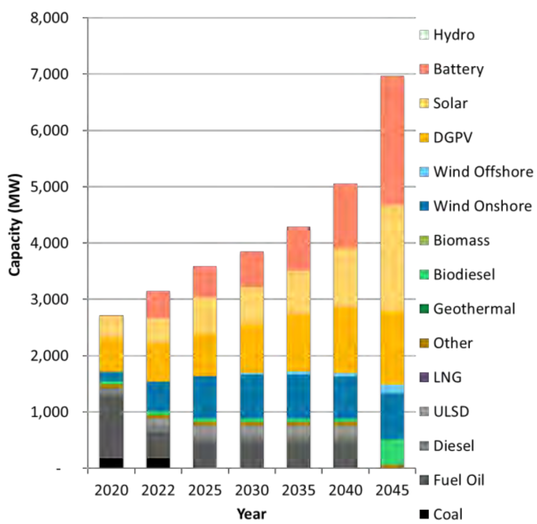


Table 26. Cumulative total resource cost for the Oahu Enhanced renewable potential No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.96	0.86	0.82	0.82	0.82	0.82	0.82
Fixed	0.97	0.93	0.90	0.88	0.87	0.87	0.83
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.22	1.71	1.49	1.33	1.25	1.20	1.13
Battery							
Capital	*Div by 0*	1.17	1.18	1.16	1.14	1.13	1.03
Total	0.99	0.99	0.98	0.98	0.97	0.97	***0.96***

4. Paniolo Wind + Pumped Storage on Hawai'i Island

The Paniolo wind and pumped-storage on Hawai'i Island case adds 30 MW of wind and 30 MW of pumped-storage hydro (PSH), with slight cost and performance changes to the base case assumptions. In this case, the combination of 30 MW of wind and 30 MW of PSH is added as a planned installation, that comes online in 2022, around which RESOLVE can optimize a least cost resource portfolio.

The results below show that the onshore wind build is very similar to the base case, with the 30 MW of Paniolo wind simply displacing 30 MW of other grid-scale onshore wind in the near-term. Compared to the base case, the 30 MW pumped-storage facility is much larger than the batteries built as a RESOLVE decision (14 MW by 2022). Further, PSH costs are higher than those of batteries, resulting in over 300% higher capital cost related to batteries* (which encompasses both batteries and Paniolo PSH in this case). On a total resource cost basis, the higher PSH cost results in a 13% increase relative to the base case under the normal operations considered by RESOLVE.

Hawai'i Island Results

Figure 25. Paniolo Wind + Pumped Storage case No-LNG Market DGPV utilized capacity results

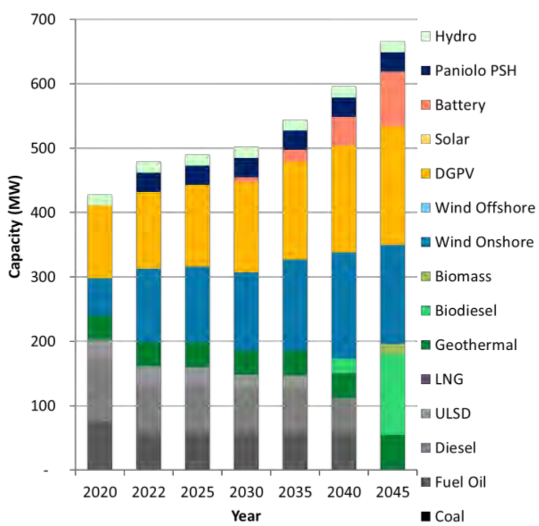


Table 27. Cumulative total resource cost for the Paniolo Wind + Pumped Storage case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.02	1.01	1.00	1.00	1.00	1.00	1.00
Fixed	1.19	1.09	1.05	1.04	1.04	1.03	0.99
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.05	1.02	1.04	1.05	1.05	1.05	1.05
Battery*							
Capital	0.00	2.86	3.82	3.72	3.72	3.59	3.37
Total	1.01	1.08	1.12	1.13	1.13	1.13	***1.13***

** Battery category includes pumped-storage hydro, which is a planned addition and not a RESOLVE decision*

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

5. Consumer Advocate No LNG No-RPS Constraint Cases

The Consumer Advocate no-RPS case results in a significantly different resource build on Oahu. The AES coal plant is kept online through 2045, which reduces the amount of other thermal usage as the price of coal remains below that of the liquid fuels. Furthermore, the thermal plants are used at a higher capacity factor than in the RPS constrained cases. There is still a significant amount of solar, batteries, and a smaller amount of offshore wind resources which are used because the renewable resources are cost competitive for energy, especially in later years of the plan. On Oahu, removing the RPS constraint leads to a case with total resource cost which is 87% of the RPS-constrained case.

On Maui and Hawai'i, however, the higher quality renewable resources are cost competitive with fuels such that the model chooses to build similar amounts of renewable sources, even in a non-RPS constrained world. The cost difference between the RPS-constrained and non-RPS-constrained cases is much smaller on these islands, with only a 1% difference on Maui and 2% difference on Hawai'i.

Oahu Results

Figure 26. Consumer Advocate Oahu No-RPS No-LNG Market DGPV utilized capacity results

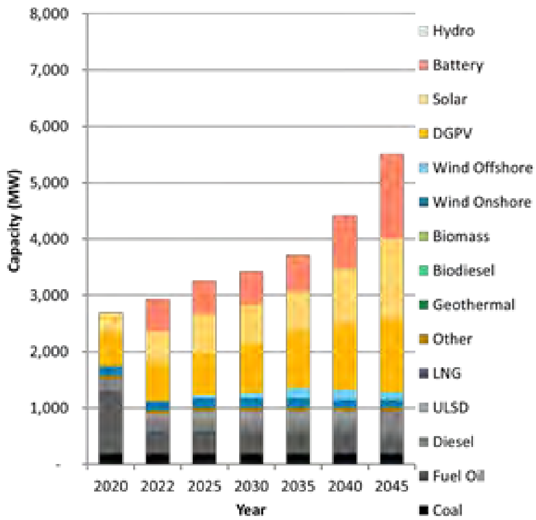


Table 28. Cumulative total resource cost for the Oahu No-RPS No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.99	0.97	0.89	0.87	0.86	0.86	0.94
Fixed	1.00	0.92	0.91	0.90	0.90	0.90	0.91
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.13	1.22	0.97	0.87	0.84	0.84	0.77
Battery							
Capital	0.00	1.38	1.33	1.25	1.18	1.13	0.94
Total	1.00	1.01	0.93	0.90	0.88	0.87	***0.87***

Maui Results

Figure 27. Consumer Advocate Maui No-RPS No-LNG Market DGPV utilized capacity results

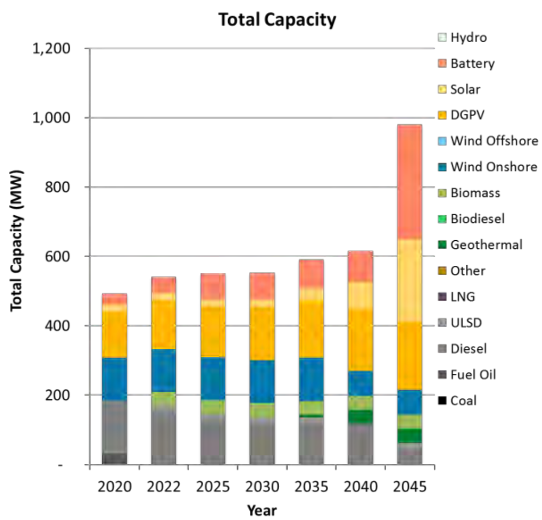


Table 29. Cumulative total resource cost for the Maui No-RPS No-LNG Market DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fixed	0.64	0.82	0.89	0.91	0.94	0.95	0.96
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.96	0.96	0.97	0.97	0.96	0.96	0.96
Battery							
Capital	*Div by 0*	2.98	1.62	1.41	1.28	1.26	1.15
Total	0.97	0.98	0.99	0.99	0.99	0.99	***0.99***

Hawai'i Island Results

Figure 28. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV utilized capacity results

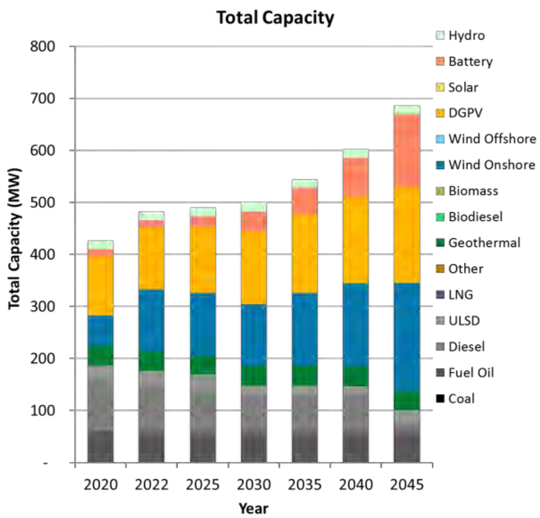


Table 30. Cumulative total resource cost for the Hawai'i Island No-RPS No-LNG Market DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	0.74
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	1.00	1.00	1.00	1.00	1.00	1.08
Battery							
Capital	1.00	1.00	1.00	1.00	1.00	0.98	1.06
Total	1.00	1.00	1.00	1.00	1.00	1.00	***0.98***

6. Consumer Advocate LNG No-RPS Constraint Cases

In the Consumer Advocate LNG No-RPS Constraint case, we extend the LNG fuel price forecast through 2045 to allow thermal units that burn LNG to continue economic operation throughout the planning horizon.

Similar to the Consumer Advocate No LNG case above, the LNG case shows significantly different build on each island; however, more thermal plants stay online throughout the planning horizon on all islands due to the low fuel cost associated with LNG. Further, low cost LNG discourages significant grid-scale renewable buildout, which is most apparent with the reduction in grid-scale solar on Oahu and Maui in 2045. As noted in Table 3, while both Consumer Advocate No-RPS Constraint cases results in sub-100% RPS-eligible energy, the LNG case results in significantly lower energy from RPS-eligible resources on all islands. From a cost perspective, the LNG No-RPS Constraint case results in a 5-7 percentage point reduction below the Company No-LNG Market DGPV case.

Oahu Results

Figure 29. Consumer Advocate Oahu No-RPS No-LNG Market DGPV utilized capacity results

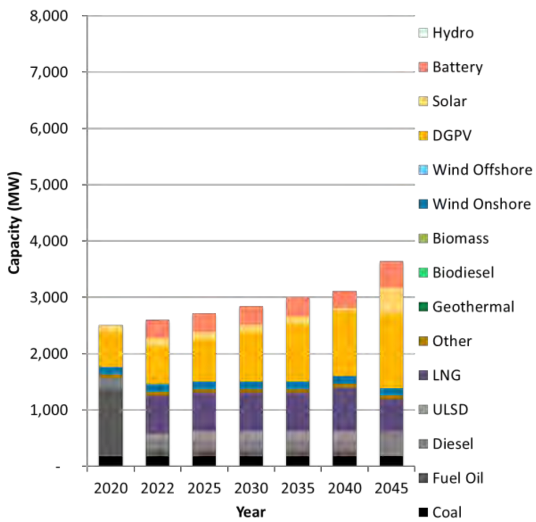


Table 31. Cumulative total resource cost for the Oahu No-RPS No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.09	0.88	0.76	0.72	0.70	0.69	0.74
Fixed	1.06	3.31	4.87	5.71	6.13	6.40	6.90
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.34	0.37	0.27	0.26	0.27	0.29	0.29
Battery							
Capital	0.00	0.76	0.74	0.69	0.65	0.60	0.45
Total	1.01	1.02	0.94	0.90	0.87	0.85	***0.84***

Maui Results

Figure 30. Consumer Advocate Maui No-RPS No-LNG Market DGPV utilized capacity results

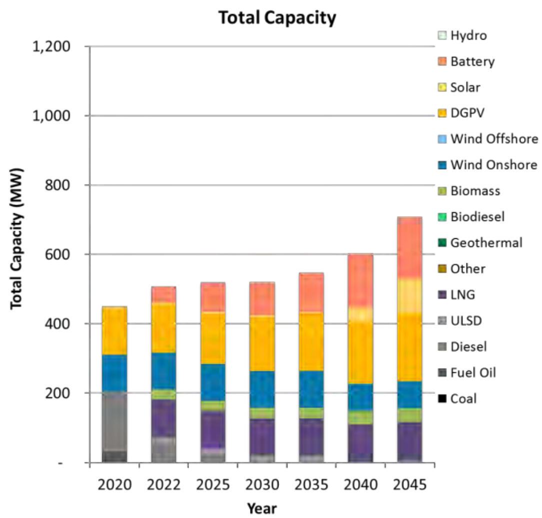


Table 32. Cumulative total resource cost for the Maui No-RPS No-LNG Market DGPV case (relative to Maui No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.17	1.01	0.90	0.82	0.78	0.76	0.81
Fixed	0.80	0.92	0.97	0.97	0.96	0.90	0.83
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	0.51	0.53	0.55	0.57	0.58	0.61	0.60
Battery							
Capital	*Div by 0*	1.39	1.21	1.23	1.24	1.29	1.02
Total	0.99	0.92	0.88	0.85	0.83	0.81	***0.80***

Hawai'i Island Results

Figure 31. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV utilized capacity results

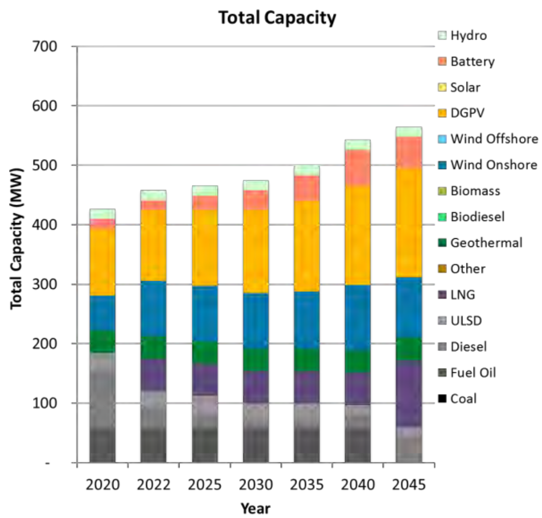


Table 33. Cumulative total resource cost for the Hawai'i Island No-RPS No-LNG Market DGPV case (relative to Hawai'i Island No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	1.00	0.90	0.82	0.76	0.73	0.71	0.75
Fixed	0.97	1.15	1.24	1.29	1.32	1.34	1.04
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.00	0.78	0.76	0.76	0.75	0.75	0.75
Battery							
Capital	1.19	1.19	1.18	1.09	1.04	1.00	0.87
Total	1.00	0.93	0.89	0.86	0.83	0.82	***0.81***

7. DBEDT No Military Units on Oahu

In the DBEDT no military unit case the Marine Corps Base Hawaii (MCBH) and Joint Base Pearl Harbor-Hickam (JBPHH) diesel power plants are not built. The model is given the option of procuring units with the same cost and performance characteristics, but RESOLVE chooses not to invest until 2045, when it procures biodiesel units with similar cost and performance characteristics to the military units. In the base case the Companies have assumed that the military units have planned fuel switching to biodiesel in 2045. RESOLVE optimizes to minimize costs by assuming normal operating conditions, with hourly reserve requirements specified by the Companies. However, RESOLVE does not capture the detailed transmission, power flow, and contingency constraints necessary to fully determine the need for new generation. These results act as a preliminary starting point based on planning level economics that will require further investigation by both parties and the Companies.

Oahu Results

Figure 32. DBEDT Oahu no military unit No-LNG Market DGPV utilized capacity

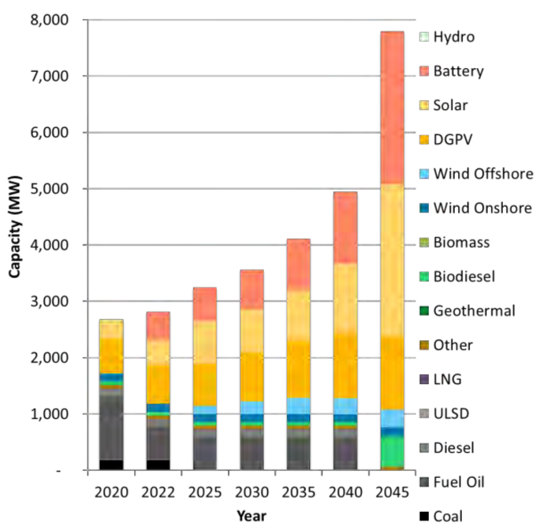


Table 34. Cumulative total resource cost for the DBEDT Oahu no military unit No-LNG Market DGPV case (relative to Oahu No-LNG Market DGPV case)

	Relative cumulative total resource costs						
	2020	2022	2025	2030	2035	2040	2045
Thermal							
Variable	0.99	0.99	0.98	0.99	0.99	0.99	0.99
Fixed	1.00	0.99	0.98	0.97	0.96	0.96	1.04
Renewables							
Variable	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed	1.07	1.05	1.06	1.03	1.02	1.02	1.01
Battery							
Capital	0.00	1.19	1.24	1.24	1.23	1.23	1.15
Total	1.00	1.01	1.01	1.02	1.02	1.02	***1.02***

APPENDIX A: COMPANIES SENSITIVITY CASE DATA

The results shown in this appendix give the total MWs of each resource through 2045. Utilized capacity are resources that RESOLVE chooses to operate for least cost economic dispatch, and to meet system reserve needs. Unutilized capacity are defined in MWs that RESOLVE does not need to meet system constraints. These are candidate MWs for retirement, should the more detailed analysis conducted by the Companies show retirement is warranted.

No-LNG Market DGPV Installed Capacities

Oahu Results

Table 35. Oahu No-LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	579/94	579/-	579/-	579/-	579/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	534/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	119/-	237/-	314/-	314/-	312/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	446/-	763/-	763/-	829/-	1161/-	2693/-
Battery	-/-	426/-	456/-	571/-	747/-	1079/-	2714/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 36. Maui No-LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	163/38	128/73	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	3/-	40/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	61/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	139/-	139/-	139/-	139/-	139/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	5/-	5/-	5/-	5/-	28/-	77/-	259/-
Battery	-/-	34/-	75/-	75/-	85/-	87/-	346/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 37. Hawai'i Island No-LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	88/8	81/16	71/25	71/25	54/-	-/-
ULSD	30/-	30/-	30/-	19/11	19/11	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	55/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	31/-	118/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	22/-
Wind Onshore	58/-	119/-	119/-	119/-	140/-	161/-	140/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	21/-	38/-	50/-	82/-	109/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

No-LNG High DGPV Installed Capacities

Oahu Results

Table 38. Oahu No-LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	579/94	579/-	579/-	579/-	579/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	514/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	143/-	214/-	265/-	265/-	273/-
DGPV	606/-	730/-	907/-	1216/-	1524/-	1833/-	2142/-
Solar	354/-	401/-	595/-	595/-	595/-	876/-	2052/-
Battery	-/-	426/-	455/-	620/-	788/-	1208/-	2733/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 39. Maui No-LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	165/36	128/73	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	37/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	57/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	126/-	126/-	126/-	126/-	126/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	140/-	178/-	243/-	307/-	371/-	435/-
Solar	5/-	5/-	5/-	5/-	5/-	5/-	127/-
Battery	-/-	32/-	75/-	75/-	89/-	121/-	362/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 40. Hawai'i Island No-LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	89/7	77/19	64/33	64/33	54/-	-/-
ULSD	30/-	30/-	30/-	5/25	5/25	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	20/-	110/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	109/-	109/-	109/-	109/-	108/-	139/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	115/-	131/-	174/-	244/-	315/-	386/-	456/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	25/-	66/-	86/-	131/-	205/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

LNG Market DGPV Installed Capacities

Oahu Results

Table 41. Oahu LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	103/94	103/-	103/-	103/-	103/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	679/-	679/-	679/-	679/-	679/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	529/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	320/-	320/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	354/-	372/-	372/-	372/-	853/-	2654/-
Battery	-/-	257/-	357/-	357/-	424/-	619/-	2715/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 42. Maui LNG Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	81/14	33/62	-/84	-/95	-/95	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	108/-	108/-	108/-	108/-	108/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	61/-
Biomass	-/-	20/-	20/-	20/-	26/-	40/-	40/-
Wind Onshore	119/-	119/-	119/-	119/-	119/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	5/-	5/-	5/-	5/-	5/-	110/-	259/-
Battery	-/-	30/-	84/-	107/-	117/-	159/-	346/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 43. Hawai'i Island Market DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	32/11	24/19	12/31	12/31	-/-	-/-
ULSD	30/-	30/-	30/-	30/-	30/-	-/-	-/-
LNG	-/-	55/-	55/-	55/-	55/-	55/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	55/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	34/-	118/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	22/-
Wind Onshore	58/-	93/-	93/-	93/-	96/-	109/-	140/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	17/-	17/-	25/-	33/-	43/-	66/-	109/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

LNG High DGPV Installed Capacities

Oahu Results

Table 44. Oahu LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1173/114	103/94	103/-	29/74	29/74	29/74	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	679/-	679/-	679/-	679/-	679/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	502/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	297/-	297/-
DGPV	606/-	730/-	907/-	1216/-	1524/-	1833/-	2142/-
Solar	227/-	227/-	227/-	227/-	227/-	410/-	1938/-
Battery	-/-	285/-	357/-	357/-	357/-	723/-	2736/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 45. Maui LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	201/-	85/10	33/62	-/84	-/95	-/95	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	108/-	108/-	108/-	108/-	108/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	57/-
Biomass	-/-	20/-	20/-	20/-	20/-	40/-	40/-
Wind Onshore	110/-	110/-	110/-	110/-	110/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	140/-	178/-	243/-	307/-	371/-	435/-
Solar	5/-	5/-	5/-	5/-	5/-	5/-	127/-
Battery	-/-	26/-	84/-	110/-	125/-	161/-	362/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 46. Hawai'i Island LNG High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	33/10	20/23	10/33	10/33	-/-	-/-
ULSD	30/-	30/-	30/-	8/22	6/24	-/-	-/-
LNG	-/-	55/-	55/-	55/-	55/-	55/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	17/-	110/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	73/-	73/-	73/-	73/-	53/-	139/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	115/-	131/-	174/-	244/-	315/-	386/-	456/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	17/-	17/-	29/-	58/-	70/-	101/-	205/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Uncurtailable DGPV Installed Capacities

Oahu Results

Table 47. Oahu Uncurtailable High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	579/94	579/-	579/-	579/-	579/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	526/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	57/-	190/-	190/-	190/-	250/-
DGPV	606/-	730/-	907/-	1216/-	1524/-	1833/-	2142/-
Solar	354/-	512/-	689/-	689/-	788/-	999/-	2157/-
Battery	-/-	426/-	487/-	833/-	1205/-	1495/-	2790/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 48. Maui Uncurtailable High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	2022	2025	2030	2035	2040	2045
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	162/38	162/38	128/73	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	37/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	57/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	120/-	120/-	120/-	120/-	120/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	140/-	178/-	243/-	307/-	371/-	435/-
Solar	5/-	5/-	5/-	5/-	5/-	5/-	127/-
Battery	17/-	34/-	75/-	75/-	89/-	121/-	362/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Results

Table 49. Hawai'i Uncurtailable High DGPV

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	2022	2025	2030	2035	2040	2045
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	89/7	88/9	88/9	88/9	54/-	-/-
ULSD	30/-	30/-	26/3	14/16	14/16	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	60/-	131/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	109/-	109/-	109/-	111/-	109/-	143/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	115/-	131/-	174/-	244/-	315/-	386/-	456/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	24/-	65/-	88/-	129/-	229/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Copperplate No-LNG Installed Capacities

Copperplate Results

Table 50. Copperplate capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1183/233	591/109	591/16	558/49	558/49	558/-	-/-
Diesel	345/82	345/82	345/82	345/71	345/82	302/82	-/-
ULSD	30/-	148/-	202/-	159/43	159/43	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	337/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	142/-	693/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	80/-
Wind Onshore	335/-	1099/-	1266/-	1266/-	1386/-	1672/-	1159/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	851/-	939/-	1017/-	1163/-	1334/-	1509/-	1688/-
Solar	203/-	203/-	203/-	203/-	245/-	272/-	739/-
Battery	-/-	324/-	406/-	406/-	406/-	539/-	1426/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

APPENDIX B: THIRD PARTY STAKEHOLDER SENSITIVITIES RESULTS

Ulupono Fuel Hedge Installed Capacities

Oahu Results

Table 51. Oahu No-LNG Market DGPV Ulupono fuel hedge capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1013/273	343/94	343/-	343/-	343/-	343/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	536/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	164/-	164/-	164/-	164/-	164/-	164/-	164/-
Wind Offshore	137/-	161/-	386/-	386/-	386/-	249/-	304/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	639/-	879/-	935/-	1120/-	1796/-	2758/-
Battery	117/-	650/-	830/-	1000/-	1139/-	1781/-	2720/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 52. Maui No-LNG Market DGPV Ulupono fuel hedge capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	23/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	136/65	135/65	118/82	118/71	118/82	118/82	-/-
ULSD	-/-	18/-	13/6	-/18	-/18	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	7/-	10/-	28/-	40/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	13/-	59/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	125/-	125/-	125/-	125/-	125/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	50/-	50/-	50/-	50/-	50/-	88/-	282/-
Battery	56/-	61/-	83/-	83/-	79/-	97/-	363/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 53. Hawai'i Island No-LNG Market DGPV Ulupono fuel hedge capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	78/19	66/30	64/33	64/33	54/-	-/-
ULSD	30/-	30/-	30/-	13/16	13/16	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	48/-	48/-	48/-	48/-	48/-	48/-	85/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	15/-	100/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	14/-
Wind Onshore	58/-	117/-	117/-	118/-	140/-	153/-	95/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	6/-	15/-	26/-	47/-	57/-	78/-	87/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Hawaii Gas Installed Capacities

Oahu Results

Table 54. Hawaii Gas capacity results for Oahu

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1138/148	103/94	103/-	103/-	103/-	103/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	674/-	674/-	674/-	674/-	674/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	532/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	164/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	315/-	315/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	354/-	608/-	608/-	608/-	874/-	2679/-
Battery	-/-	262/-	282/-	282/-	327/-	674/-	2715/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Fripp/Ulupono/Blue Planet Enhanced Renewable Potential on Oahu Installed Capacities

Oahu Results

Table 55. Enhanced renewable potential case No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1114/173	469/94	469/-	469/-	469/-	469/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	444/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	164/-	533/-	763/-	782/-	782/-	752/-	818/-
Wind Offshore	-/-	-/-	-/-	27/-	61/-	62/-	156/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	384/-	444/-	653/-	653/-	772/-	1049/-	1883/-
Battery	7/-	486/-	544/-	642/-	781/-	1150/-	2286/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Paniolo Wind + Pumped Storage on Hawai'i Island Installed Capacities

Hawai'i Island Results

Table 56. Paniolo case No-LNG Market DGPV capacity results

	Utilized Capacity (MW) / Unutilized Capacity (MW)						
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	75/32	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	76/21	75/22	70/27	69/28	54/-	-/-
ULSD	30/-	27/3	27/3	20/9	20/9	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Paniolo PSH	-/-	30/-	30/-	30/-	30/-	30/-	30/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	55/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	23/-	125/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	16/-
Wind Onshore	58/-	114/-	118/-	121/-	142/-	165/-	154/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	-/-	-/-	-/-	8/-	18/-	45/-	85/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Consumer Advocate No LNG No-RPS Constraint Installed Capacities

Oahu Results

Table 57. Consumer Advocate Oahu No-RPS No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	180/-	180/-	180/-	180/-	180/-
Fuel Oil	1135/151	421/94	421/-	421/-	421/-	421/-	319/-
Diesel	187/-	187/-	187/-	187/-	187/-	187/-	444/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	164/-	164/-	164/-	164/-	164/-	134/-	134/-
Wind Offshore	-/-	-/-	46/-	89/-	176/-	176/-	130/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	553/-	709/-	709/-	709/-	1002/-	1429/-
Battery	-/-	587/-	587/-	587/-	646/-	935/-	1497/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 58. Consumer Advocate Maui No-RPS No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	151/49	151/49	128/73	118/71	118/82	118/82	63/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	7/-	40/-	40/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	40/-	40/-	40/-	40/-	40/-	40/-
Wind Onshore	124/-	124/-	124/-	124/-	124/-	72/-	72/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	22/-	22/-	22/-	22/-	35/-	77/-	238/-
Battery	30/-	45/-	75/-	75/-	81/-	87/-	331/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 59. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	61/46	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	88/8	81/16	71/25	71/25	89/-	100/-
ULSD	30/-	30/-	30/-	19/11	19/11	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	119/-	119/-	119/-	140/-	160/-	208/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	14/-	14/-	21/-	38/-	50/-	75/-	141/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

Consumer Advocate LNG No-RPS Constraint Installed Capacities

Oahu Results

Table 60. Consumer Advocate Oahu No-RPS No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	180/-	180/-	180/-	180/-	180/-
Fuel Oil	1196/91	106/91	103/-	103/-	103/-	103/-	-/-
Diesel	187/-	187/-	187/-	187/-	187/-	187/-	444/-
ULSD	-/-	100/-	154/-	154/-	154/-	154/-	-/-
LNG	-/-	679/-	679/-	679/-	679/-	771/-	563/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	134/-	134/-	134/-	134/-	134/-	134/-	134/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	141/-	141/-	141/-	141/-	141/-	54/-	478/-
Battery	-/-	326/-	326/-	326/-	344/-	294/-	464/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

Maui Results

Table 61. Consumer Advocate Maui No-RPS No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	0/-	0/-	0/-	0/-	0/-	0/-	0/-
Fuel Oil	32/-	-/-	-/-	-/-	-/-	-/-	-/-
Diesel	173/28	55/40	23/72	2/82	2/93	2/93	9/-
ULSD	-/-	18/-	18/-	18/-	18/-	-/-	-/-
LNG	-/-	108/-	108/-	108/-	108/-	108/-	108/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	30/-	30/-	30/-	30/-	40/-	40/-
Wind Onshore	105/-	105/-	105/-	105/-	105/-	78/-	78/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	132/-	139/-	144/-	155/-	166/-	180/-	196/-
Solar	5/-	5/-	5/-	5/-	5/-	39/-	99/-
Battery	1/-	46/-	84/-	96/-	112/-	156/-	177/-
Hydro	1/-	1/-	1/-	1/-	1/-	1/-	1/-

Hawai'i Island Results

Table 62. Consumer Advocate Hawai'i Island No-RPS No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	58/49	58/49	58/49	58/49	58/49	58/-	-/-
Diesel	97/-	32/11	24/19	12/31	12/31	22/-	43/-
ULSD	30/-	30/-	30/-	30/-	30/-	17/-	17/-
LNG	-/-	55/-	55/-	55/-	55/-	55/-	113/-
Other	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Geothermal	38/-	38/-	38/-	38/-	38/-	38/-	38/-
Biodiesel	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	58/-	93/-	93/-	93/-	96/-	110/-	102/-
Wind Offshore	-/-	-/-	-/-	-/-	-/-	-/-	-/-
DGPV	113/-	119/-	127/-	140/-	152/-	166/-	184/-
Solar	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Battery	17/-	17/-	25/-	33/-	43/-	61/-	52/-
Hydro	17/-	17/-	17/-	17/-	17/-	17/-	17/-

DBEDT No Military Units on Oahu Installed Capacities

Oahu Results

Table 63. DBEDT Oahu No Military Unit No-LNG Market DGPV capacity results

Utilized Capacity (MW) / Unutilized Capacity (MW)							
	2020	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**
Coal	180/-	180/-	-/-	-/-	-/-	-/-	-/-
Fuel Oil	1137/150	598/94	598/-	598/-	598/-	598/-	-/-
Diesel	130/-	130/-	130/-	130/-	130/-	130/-	-/-
ULSD	-/-	-/-	-/-	-/-	-/-	-/-	-/-
LNG	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Other	69/-	69/-	69/-	69/-	69/-	69/-	69/-
Geothermal	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Biodiesel	57/-	57/-	57/-	57/-	57/-	57/-	534/-
Biomass	-/-	-/-	-/-	-/-	-/-	-/-	-/-
Wind Onshore	149/-	149/-	149/-	149/-	149/-	134/-	164/-
Wind Offshore	-/-	-/-	140/-	226/-	286/-	286/-	312/-
DGPV	606/-	680/-	745/-	869/-	1015/-	1163/-	1308/-
Solar	354/-	446/-	764/-	764/-	898/-	1229/-	2693/-
Battery	-/-	506/-	592/-	701/-	908/-	1279/-	2714/-
Hydro	-/-	-/-	-/-	-/-	-/-	-/-	-/-

APPENDIX C: PRM METHODOLOGY USED IN RESOLVE

Planning reserve margin (PRM) is designed to ensure that enough dependable generation capacity is available to meet expected demand in the planning horizon. It is defined as the differences between the resources available and the expected peak period loads. Under conventional conditions, a system planner can calculate expected peak load and ensure there are enough reliable dispatchable resources available to meet the expected peak load plus some margin for reserves, contingencies, planned maintenance, and unplanned events. Typically this process involves choosing a reliability standard based on an expected loss of load probability LOLP (e.g., 1 day in 10 years), and a corresponding PRM designed to maintain that LOLP over the planning horizon in each plan. However, for jurisdictions that are increasing their dependence on renewable or Variable Energy Resources (VERs) to meet their RPS requirements, the simple PRM calculation above needs to account for the specific VERs contributions to PRM at each stage in the plan.

Because VERs produce energy that is stochastic by nature, it is unreasonable to count their entire nameplate capacity in calculating the amount of resources available to meet PRM (i.e., a 20MW wind plant should not contribute 20MW to the PRM). Conversely, completely ignoring the renewable resources in the PRM calculation would result in an excessive thermal build that is unused for large amounts of time because of expensive fuel costs or RPS constraints. The RESOLVE methodology creates a simple metric representing the amount of capacity a planner can rely on to attribute to renewable resources in maintaining "dependable capacity."

Unlike a traditional PRM calculation which is focused on maintaining sufficient capacity to serve the expected peak load, the PRM methodology outlined below is calculated for every hour in the planning horizon. While only one of these hours is binding, we cannot identify that hour because it is determined by an interplay of energy demand, demand response, DGPV, and the "dependable capacity" produced for each renewable resource. For example, the binding hour for PRM in a system with only solar renewable resources will likely occur in the evening, and the binding hour for a system with a combination of wind and solar resources could easily occur much earlier in the day. Below, we describe the methodology used to value the PRM contribution of renewable resources in this planning study that incorporates that interplay.

We begin with normalized hourly generation shapes for each renewable resource. In this case, the normalized hourly generation shapes were produced by the National Renewable Energy Laboratory and are hourly forecasted generation for 2045.

CALCULATION STEPS:

1. Calculate the distribution of the hourly renewable output for each renewable resource for each season-hour (e.g., summer hours 1-24).
2. Calculate the 10^{th} percentile of each distribution above (10^{th} percentile to represent the energy a planner can rely on for the identified renewable resource to provide with a 90% confidence level).
3. Use the identified 10^{th} percentile calculated for each renewable resource in each season-hour and map it to the entire year (e.g., apply the 10^{th} percentile value for Summer Hr 12 to the 12^{th} hour of all summer days in the year in question in the plan on each island).
4. For each renewable resource, multiply the hourly 10^{th} percentile values calculated above in Step 3 by the installed nameplate capacity of the renewable resource to calculate the hourly "dependable capacity" MW contribution of that renewable resource to the PRM.
    a. For example: assume the 10^{th} percentile for solar Summer Hr 12 was 0.10, and the system had 110MW of nameplate solar installed. Then, the solar contribution to PRM during each Summer Hr 12 would be 0.10*110MW = 11MW.
5. For each hour, add together the PRM contributions from renewable resources, thermal resources, and batteries (thermal and battery contributions described below) to calculate the hourly PRM generation available.
6. Compare the available PRM generation with the PRM requirement, which is specified as a multiplier (greater than 1) of the hourly load.
7. If the generation side of the PRM constraint is greater than the load side for all hours, the PRM requirement has been met for the year in question. If there are one or more hours in which the PRM load requirement is greater than the generation resources available to meet PRM, the model must procure additional generation resources at least cost.

In this way, RESOLVE can rely on some level of renewable output for capacity instead of relying solely on an increasingly lower capacity factor thermal fleet in a high RPS world.

THERMAL AND BATTERY CONTRIBUTION TO PRM

Thermal resources contribute their maximum rated power output towards the PRM constraint.

In this planning study, we find that batteries are built more for energy purposes (i.e., absorbing high renewable output hours and shifting the energy to lower output hours) than for providing capacity. Nevertheless, we allow batteries to contribute to PRM. A battery's contribution to the PRM constraint is the power output a battery could discharge for 4 hours. For example, if a battery held 4kWh of energy in its pack, then its contribution to PRM would be 1kW as that is the power output the battery could maintain for 4 hours. This 4-hour cutoff is consistent with planning methodology used in the California market, which is one of the few markets with explicit formulations for how to evaluate the planning and capacity contributions of batteries.

Suitability of using a simple single hour and fixed PRM Number

The methodology described above is relatively simple and designed to determine the economic comparison of costs and benefits of a large number of cases over a relatively short period. It is largely unbiased towards different resources and is therefore suitable for comparing the costs of each plan.

Although the proposed process accounts for a VERs contribution to meeting a simple single PRM calculation for a single hour, the approach is too simple to assure that the reliability between each plan or over the course of each plan is maintained. For this reason, the companies have proposed using a number of other models to test the reliability of each of the studied plans; however, even that analysis is probably insufficient and limited by time, data and analytical tools. In particular, the simple single hour contribution of each VER and the fixed PRM percentage over the course of the expansion plan are simplifications that need to be tested.

In California, as part of their long term planning process, we are currently building a version of RESOLVE that incorporates information from our RECAP model that determines the amount specific LOLP and PRM needed for each plan over time and the Equivalent Load Carrying Capability (ELCC) of each VER over time in each plan as a more accurate way to counting VERs in their contribution to dependable capacity. A description of how RESOLVE is being adapted to incorporate a more detailed check on reliability in California can be found here:

http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451565

ASCEND ANALYTICS: ASCEND OPTIMAL RESOURCE ANALYSIS

ASCEND OPTIMAL RESOURCE ANALYSIS

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December 16, 2016

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Contents

Executive Summary

Ascend Analytics ("Ascend") of Boulder, Colorado, was selected by Hawaiian Electric Companies ("the Companies") to perform modeling analysis on the Post-April PSIP Plans developed in the Companies' December 2016 PSIP filing. Ascend performed modeling analysis using its PowerSimm software.

Ascend performed validation of resource plans developed by the Companies and the Companies' consultant Energy and Environmental Economics (E3). The following plans were validated by Ascend's PowerSimm software:

Oahu (OAHU)
Post-April PSIP Plan
E3 Plan – Least cost resource plan without LNG
E3 Plan with LNG – least cost resource plan with LNG
Hawaii (HELCO)
Post-April PSIP Plan developed by the Companies
E3 Plan – least cost resource plan without LNG
Maui (MECO)
Post-April PSIP Plan developed by the Companies
E3 Plan – least cost resource plan without LNG

Table 1: Summary of the plans developed by the Companies and E3, which Ascend evaluated through Powersimm.

PowerSimm's evaluation of the Post-April PSIP Plans and E3 Plans align with the general trends found in Companies' evaluation of these plans through their Plexos model. As in the Plexos evaluations, PowerSimm found there to be only a marginal difference between the Oahu E3 Plan and the Oahu Post-April PSIP Plan, while calculating a significant reduction in costs for the Oahu E3 Plan with LNG relative to the Post-April PSIP Plan. For the Maui E3 Plan, PowerSimm calculated an 8% reduction in costs when compared with the Maui Post-April PSIP Plan, while Plexos results show an 7% reduction. For Hawaii, PowerSimm calculated a 2% reduction in total costs, and Plexos calculated a 9% reduction in total costs.

Ascend also utilized PowerSimm to evaluate the merits of adding flexible thermal units to Oahu's thermal fleet. With Oahu's high renewable penetration rates, thermal generation's role shifts from meeting base load to complementing the increasing levels of intermittent renewable generation. Since wind and solar generation cannot be regulated to meet changes in load, thermal generation becomes a key asset in addressing the imbalances that arise between supply and load in a system with such variable outputs. To respond to these imbalances, thermal units have to be flexible, ramping up, ramping down, starting up and shutting off much more frequently than in the past. PowerSimm determined the optimal introduction of flexible thermal unit additions to Oahu's preexisting thermal fleet. Ascend then compared Oahu's forecasted costs with (1) its existing fleet, (2) the Post-April PSIP Plan's updated fleet, and (3) the updated fleet developed by Ascend. The results show that the addition of flexible thermal units to the preexisting fleet can provide significant savings.

In addition to validating the Post-April PSIP Plans and E3 Plans, Ascend has further optimized the Post-April PSIP Plans by utilizing PowerSimm software to systematically incorporate uncertainty into the planning process. By rigorously simulating the impact of weather on renewables and load, PowerSimm determined the need for substantial additions of batteries that can respond to the natural variability of high renewable penetration rates. Ascend has determined the economic and operational merit of adding a substantial volume of energy storage by 2045. PowerSimm also incorporated uncertainty in fuel prices that helped determine the economic merit of increased expansion of renewable generation in excess of the RPS standards. For example, the optimal mix of renewables for Oahu includes a 57% increase in forecasted utility solar introductions, a 21% increase in forecasted offshore wind introductions, and an optimized battery buildout plan that reaches 10,000 MWh by 2045. The results of PowerSimm's optimization of renewables and batteries for Oahu are presented below in Figure 1.

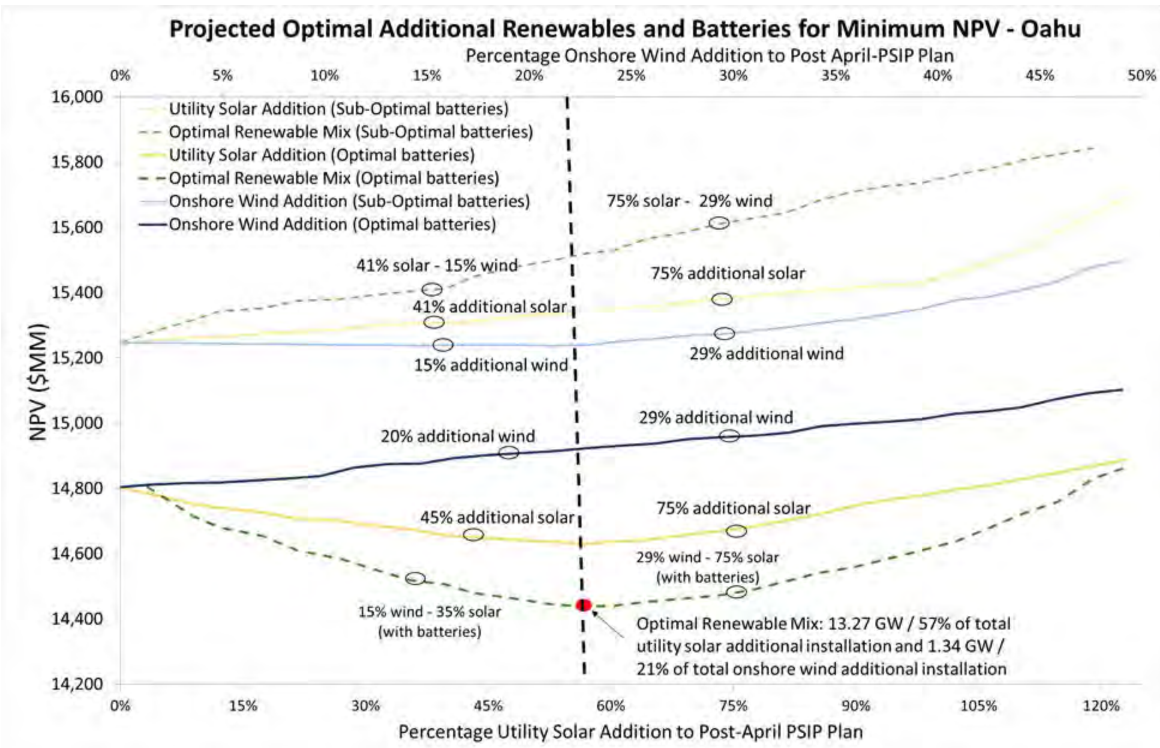


Figure 1: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries for Oahu's portfolio.

Ascend also optimized the Post-April PSIP Plans for Maui and Hawaii. The optimal resource mix for Maui includes a 74% increase in utility solar, a 34% increase in onshore wind, and the addition of 2,400 MWh batteries. The optimal resource mix for Hawaii includes an 87% increase in forecasted onshore wind introductions, and an optimized battery buildout plan that reaches 180 MWh by 2045.

For each of the islands, Ascend compares the net present value (NPV) of total portfolio costs from the present to 2045 for the original Post-April PSIP Plan, the two E3 Plans, as well as two Ascend-developed Plans. The two Ascend-developed plans are: 1) Ascend's optimization of the Post-April PSIP Plan with batteries (the Post-April PSIP Plan with Batteries), 2) Ascend's optimization of the Post-April PSIP Plan with renewables and batteries (the Ascend Plan). Relative to the original Post-April PSIP Plans, the Post-April PSIP Plans with Batteries provide a 1%-3% reduction in NPV portfolio costs for the Companies, while the Ascend Plans provide a slightly larger reduction of 3-5% in NPV portfolio costs for the Companies.

PowerSimm also analyzed resource adequacy under conditions of increasing intermittent renewable penetration. PowerSimm's analysis demonstrates that while intermittent renewables combined with batteries reduce the Companies' need for thermal generation, they do not nullify this need. Utilizing its ability to capture a wide range of possible future conditions, PowerSimm shows that a significant level of thermal generation capacity will still be necessary to reliably meet load by 2045, when the Companies' resource mix will be 100% renewable. Since there is always a possibility for extreme weather scenarios that severely reduce solar and wind generation, the Companies' thermal fleet has to have sufficient capacity to make up for substantial losses in intermittent renewable generation in order to ensure future resource adequacy. Ascend assessed the Loss of Load Probability (LOLP), or the probability of outages due to load exceeding supply, for the plans. The results indicate that the Oahu E3 Plan and the Maui E3 Plan would not be able to maintain the security of the energy supply, leading to higher chances of power outages. Both the Oahu and Maui E3 Plans accelerate the retirement of thermal generators without providing sufficient updates to the thermal fleet. These results suggest that upgradations of the thermal fleet would be an essential component of a viable integrated resource plan.

The analysis of all the plans and their optimized derivations was conducted on an hourly scale. To gain more insight into the sub-hourly dynamics of the Companies' power systems under conditions of higher renewable penetration, Ascend utilized PowerSimm's System Flexibility Software. System Flexibility Software uses historical renewable generation data to evaluate at the minutely level the Companies' flexible generation requirements (i.e. minutely, sub-hourly and hourly ramps and cycles) that accompany the integration of intermittent renewables. The results demonstrate that flexible generation requirements increase dramatically with the increasing levels of intermittent renewable generation, particularly with increasing solar. Batteries provide an excellent option for balancing out these sub-hourly and hourly fluctuations because of their ability to discharge energy precisely and extremely rapidly, with no additional production costs.

Ascend compared the costs of meeting these flexible generation requirements with batteries versus with conventional thermal generation. For this section, PowerSimm evaluates batteries that charge and discharge on an hourly scale (flexible batteries) and minutely scale (regulation batteries). Importantly, regulation batteries are not included in the optimized plans, which were developed and evaluated on an hourly-scale. The results support an introduction into Oahu's system of flexibility batteries by 2022 and an immediate introduction of regulation batteries. The savings provided by these two types of battery grow over time with the higher renewable penetration rates.

In sum, through the analysis of the given resource plans and the development of the Ascend-optimized resource plans, this report provides insight into: (1) the benefits of flexible thermal generation with higher renewable penetration, (2) the benefits of load-shifting batteries with higher renewable penetration, (3) the necessity for substantial dispatchable generation in order to maintain resource adequacy in a system with higher levels of intermittent renewables, and (4) the benefits of serving regulation with batteries instead of with conventional thermal generation in a system with higher levels of intermittent renewables.

1. Background

Following their April 2016 Power Supply Improvement Plan (PSIP) filing, Hawaiian Electric Companies ("the Companies") selected Ascend Analytics ("Ascend") of Boulder, Colorado, to perform modeling analysis on the plans developed for the December PSIP filing using Ascend's PowerSimm suite of products. PowerSimm is an analytics platform that systematically incorporates uncertainty into resource selection and capacity expansion planning.

This report's objective is to evaluate the Companies' Post-April PSIP Plans and E3's optimization of these plans, as well as to optimize the original Post-April PSIP Plans through the utilization of Ascend's PowerSimm model. In this report, Ascend will first provide PowerSimm's evaluation of the Post-April PSIP Plans and E3 plans for each island system. Second, this report will go over the benefits of flexible thermal generation for Oahu, presenting the optimal introduction of flexible thermal units into Oahu's thermal fleet. Third, this report will present PowerSimm's analysis on resource adequacy for the plans, highlighting the need to maintain sufficient dispatchable generation capacity to ensure the security of supply under all weather conditions. Fourth, this report will present the details on the resource plans created by Ascend for each of the three island systems, comparing them to the non-Ascend resource plans discussed earlier in the report. Fifth, this report will detail the sub-hourly and hourly flexible generation requirements that accompany high levels of intermittent renewable penetration, and additionally show the benefits of utilizing batteries to address these flexible generation requirements.

For each of the three island systems, Ascend analyzes and compares four plans, two that were not developed by Ascend, and two that were developed by Ascend. For Oahu, Ascend evaluates an additional non-Ascend Plan. The plans not created by Ascend (i.e., the original Post-April PSIP Plan, the E3 Plan and the E3 Plan with LNG) will be reviewed in Section 2. The two plans developed by Ascend (i.e., the Post April PSIP Plan optimized with batteries, and the Post-April PSIP Plan optimized with both renewables and batteries) will reviewed in Section 4, and then compared to the three other plans. A summary of all the plans included in this report are provided in Table 2 below.

	Name	Brief Description
Non-Ascend resource plans evaluated by Ascend (Detailed in Section 2)	Post-April PSIP Plan	Post-April PSIP Plan without modification
	E3 Plan[1]	Post-April PSIP plan optimized through E3's RESOLVE model; no LNG
	E3 Plan with LNG (only for Oahu)	Post-April PSIP plan optimized through E3's RESOLVE model; with LNG
Ascend-developed resource plans (Detailed and compared with non-Ascend plans in Section 4)	Post-April PSIP Plan with Batteries[2]	Original Post-April PSIP plan with an Ascend-optimized battery buildout plan
	Ascend Plan	Post-April PSIP plan with optimized levels of utility PV and offshore wind, and optimal battery buildout plan

Table 2: Plans included in this report.

Importantly, the Post-April PSIP Plans have slightly different assumptions in Section 2 and Section 4. As opposed to its "High" DGPV assumptions in the initial comparison with the E3 Plans in Section 2, the Post-

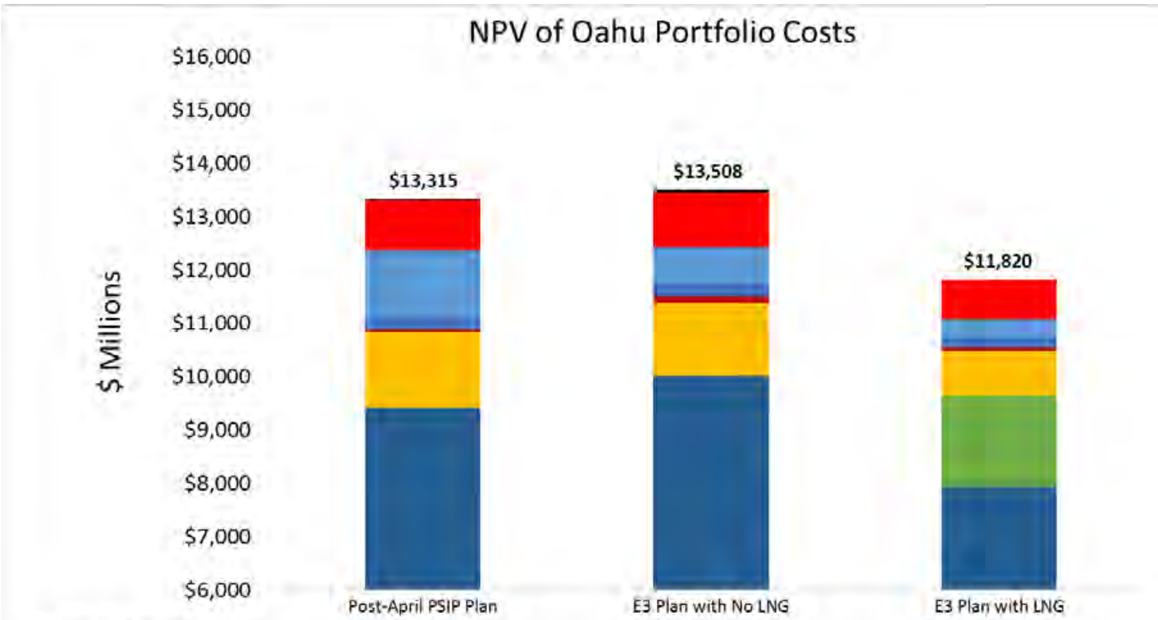
[1] In addition to the two plans, Ascend also evaluates the E3 Plan with LNG for Oahu.
[2] It is worth noting that the original Post-April PSIP Plans do include batteries, but at sub-optimal levels. Ascend uses the naming convention 'Post April Plan with Batteries' for the sake of expediency.

April PSIP Plans in Section 4 contain lower, "Market" DGPV assumptions in the comparison with the Ascend-developed plans, which also use the Market DGPV assumptions. The E3 Plans evaluated in Section 2 and Section 4 are identical, containing High DGPV assumptions.

Additionally, the costs of the plans are calculated in a slightly different manner in Section 2 and Section 4. In Section 2 the total costs of the plans are calculated without DGPV costs, while in Section 4 they are calculated with DGPV costs included.

2. Validation of Post-April PSIP Plans and E3 Plans

Ascend used PowerSimm to evaluate the total net present value (NPV) of portfolio costs for the Post-April PSIP Plan and the E3 Plan with no LNG for each island system. Additionally, PowerSimm analyzed the NPV Portfolio costs of the Oahu E3 Plan with LNG.



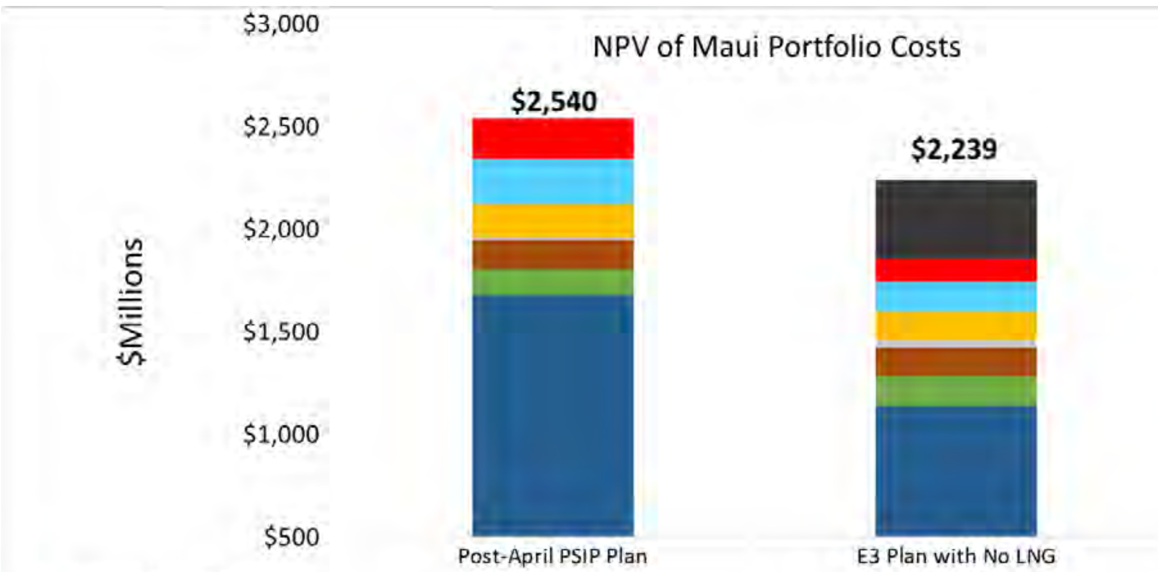
	Post-April PSIP Plan	E3 Plan with No LNG	E3 Plan with LNG
Unserved Energy Cost	$1	$54	$0
Risk Premium	$942	$1,016	$741
Capital Costs (Offshore Wind)	$1,251	$686	$354
Capital Costs (Onshore Wind)	$226	$240	$170
Capital Costs (Batteries)	$46	$131	$71
Capital Costs (Utility PV)	$1,436	$1,367	$843
Capital + Fixed Costs (LNG)	$0	$0	$1,704
Production Costs	$9,413	$10,015	$7,936

Figure 2: NPV Portfolio Costs for the Oahu Post-April PSIP Plan and E3 Plans.

According to PowerSimm's results, the E3 Plan has an NPV Portfolio cost that is $193 M higher than the original Post-April PSIP Plan. The E3 Plan installs less renewable capacity than the Post-April PSIP Plan. In particular, the offshore wind capital costs for the E3 Plan is 45% less than the offshore wind capital costs for the Post April-PSIP Plan. Thus more thermal generation must be utilized in the E3 plan, causing the E3 plan to have $602 M more in production costs than the Post-April PSIP Plan.

PowerSimm incorporates into its evaluation of NPV portfolio costs penalties for a resource plan's expected shortfalls in meeting load under the Unserved Energy Cost category. For each MWh short, PowerSimm provides a penalty of $10,000. Since the Oahu E3 Plan falls short in meeting resource adequacy standards, its portfolio costs rise by $50 M with the inclusion of these penalties. The results of PowerSimm's analysis of resource adequacy for the Oahu plans are discussed in section 4.3.1.

Compared to the original Post-April PSIP Plan, the E3 Plan reduces portfolio costs by 11%, or $1,495 M. The lower fuel prices of LNG are the chief contributor to the lower NPV costs. LNG conversion reduces total production costs by $1,477 dollars. Additionally, since LNG fuel prices are less volatile, the risk premium, which monetizes the risk of fuel exceeding the mean of its forecasted price, decreases significantly for the E3 Plan with LNG.



	Post-April PSIP Plan	E3 Plan with No LNG
Unserved Energy Cost	$0	$382
Risk Premium	$199	$113
Capital Costs (Onshore Wind)	$217	$146
Capital Costs (Utility Solar)	$162	$139
Capital Costs (Battery Storage)	$15	$37
Capital Costs (Geothermal)	$141	$134
Capital Costs (Biomass)	$124	$152
Production Costs	$1,683	$1,138

Figure 3: NPV Portfolio costs of the Maui Post-April PSIP Plan and E3 Plan.

Relative to the Maui Post-April PSIP Plan, the Maui E3 Plan reduces portfolio costs by $301 M. For intermittent renewables, the E3 Plan's capital costs are $94 M less than the Post April PSIP Plans' capital costs. Even more striking is the reduction of $545 M in production costs provided by the E3 Plan. However, the Maui E3 Plan fails to meet resource adequacy standards to an even greater degree than the Oahu E3

Plan, which adds $382 M to its portfolio costs. PowerSimm's analysis of resource adequacy for the Maui E3 Plan will be discussed in section 4.3.2.

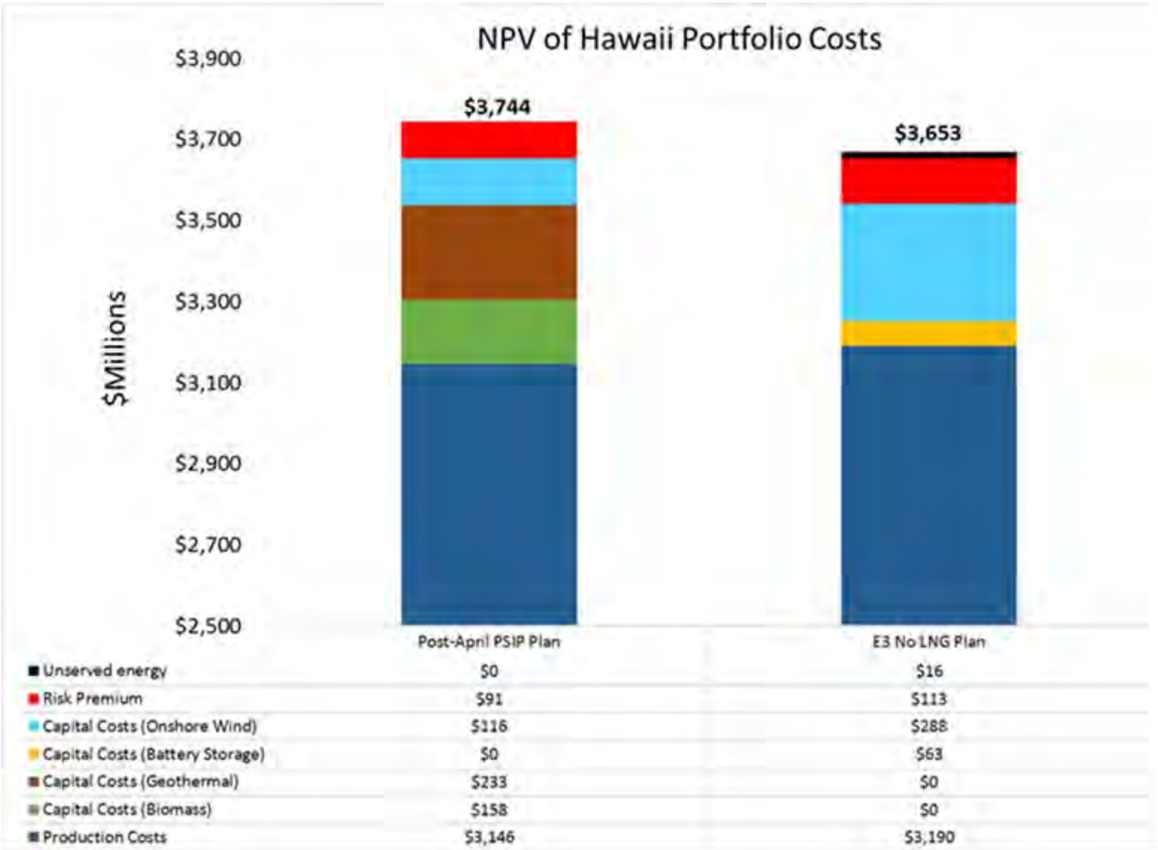


Figure 4: NPV Portfolio Costs the Hawaii Post-April PSIP Plan and E3 Plan.

Compared to the Hawaii Post-April PSIP Plan, the Hawaii E3 Plan lowers NPV Portfolio costs by $91 M.

Though Ascend's evaluation through PowerSimm and the Companies' evaluation through Plexos differ in their forecasted costs for the plans, the general trends of the results from the two models show a relative consistency. The table below shows the percent difference in total costs for each E3 Plan relative to the base Post-April PSIP Plan according to the two models.

Percent difference in costs of E3 Plan relative to Post-April PSIP Plan with Plexos and PowerSimm		
	Plexos Evaluation	**PowerSimm Evaluation**
Oahu E3 Plan	-0.1%	+1.4%
Oahu E3 Plan with LNG	-7.6%	-11.2%
Maui E3 Plan	-7.0%	-8.2%
Hawaii E3 Plan	-9.4%	-2.4%

Table 3: Comparison of evaluation of plans by Plexos and PowerSimm

3. Flexible Thermal Generation

The transition to a high renewable energy portfolio paradoxically requires the restructuring Oahu's thermal generation to a more flexible fleet. While at first blush one may see little merit in new thermal generation, this investment remains a critical component of the thermal transition to a 100% renewable portfolio. Even in 2045, variable meteorologies create conditions, which necessitate the use of thermal generation.

With high intermittent renewable penetration, the operating patterns of dispatchable generation alter significantly. Instead of providing power at steady rates throughout the day, thermal generation is expected to ramp up and down rapidly to address the imbalances between load and supply that comes from solar and wind generation's volatility. This section will elucidate the need for flexible thermal generation. Then this section will present Ascend's optimized additions to Oahu's thermal fleet, as well as a comparison between PowerSimm's calculations of the total costs for (1) Oahu's existing thermal fleet with no updates, (2) Oahu's Ascend-optimized flexible thermal fleet, and (3) the updated flexible thermal fleet contained in the Oahu Post-April PSIP Plan. Ascend will provide the total costs of these three thermal fleets under conditions of perfect and imperfect foresight.

3.1. The Need for Flexible Thermal Generation

Since the availability of wind and solar generation is contingent on weather patterns and their output is taken before thermal generation, the operating patterns of thermal generation have to undergo a shift in a system with high penetration rates of intermittent renewable generation. Thermal generation shifts from operating at base load to operating on a more flexible and irregular basis, serving load during the periods when wind and solar cannot provide sufficient generation to meet load.

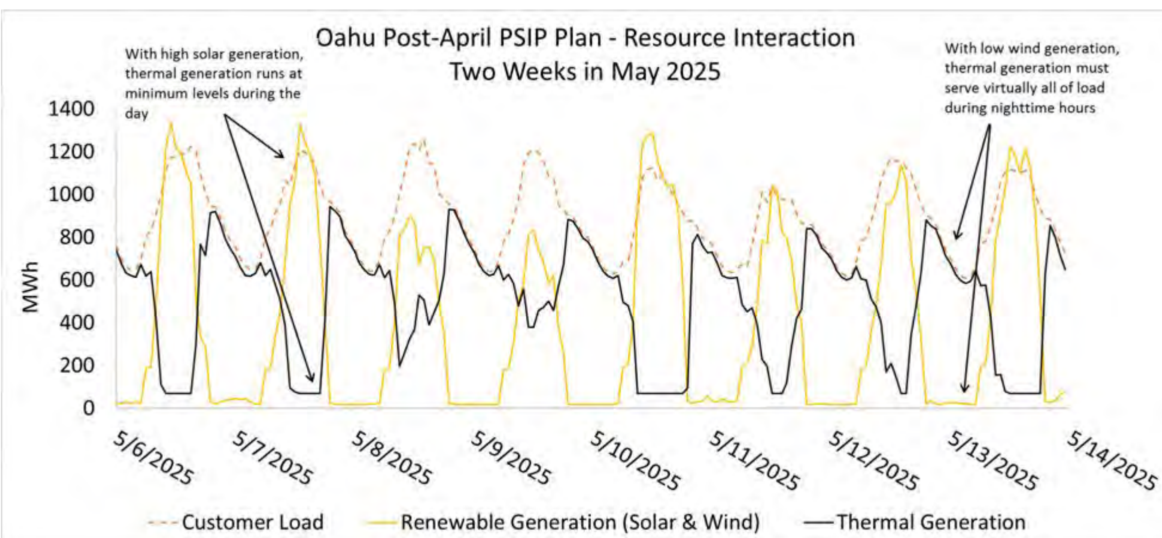


Figure 5: Resource interaction for two-week period in May, 2025.

Figure 5 presents a typical example of thermal generation operations under Oahu's growing levels of intermittent renewable penetration in 2025. Thermal generation is very low when solar generation peaks during the middle of the day and is thus able to serve the majority of load. Since, during solar's off-peak hours, there is very little wind generation, thermal generation must ramp up to meet load, virtually serving all of load for the majority of the evening and night-time hours.

Under such operating conditions, having thermal generation units that are relatively inflexible can incur significant production costs. With higher intermittent renewable penetration, the production costs with an inflexible thermal fleet are higher than with a flexible fleet because inflexible generators, such as steam generators, will be required to come online to serve load for relatively short durations during peaking conditions. Steam units have long minimum-run times, usually around 12 hours. Thus, if additional thermal generation is only necessary for 4 hours, steam units will have to continue to run for 8 more hours at minimum generation. Since steam units run much more inefficiently at minimum generation than at maximum generation, production costs rise in such scenarios. On the other hand, a flexible thermal unit such as a combined cycle generator (CC) has a minimum run time of 1-hour. Thus, if additional thermal generation is only necessary for 4 hours, CCs can shut off immediately thereafter, incurring no additional costs.

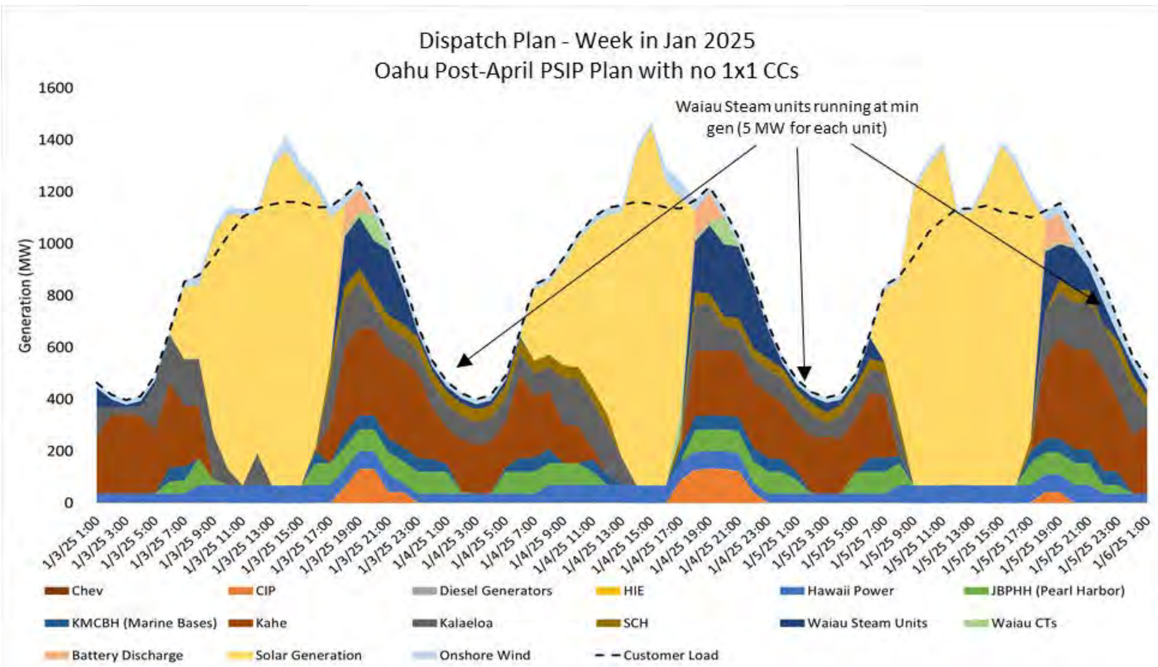


Figure 6: Dispatch Plan without 1x1 combined cycle generators, January, 2025.

Figure 6 provides an example of rising production costs without flexible thermal generation. The most important aspect to note in this dispatch plan is the thermal generation of the Waiau steam units (shaded dark blue). On January 23rd, the Waiau units come online at approximately 5:00 p.m., when solar generation (shaded yellow) declines, in order to meet load. After 11:00 p.m. the Waiau units' generation is no longer necessary to meet load, but, since they have a minimum run-time of 12 hours, they have to continue to run at minimum generation (5 MW per unit) until 5:00 am. At these must-run generation levels, the steam units operate at a relatively inefficient heat rate (21 MBtu/MWh) compared to when they operate at maximum capacity (10-11 MMBt/MWh). Thus, keeping these units running at minimum generation incurs significant costs.

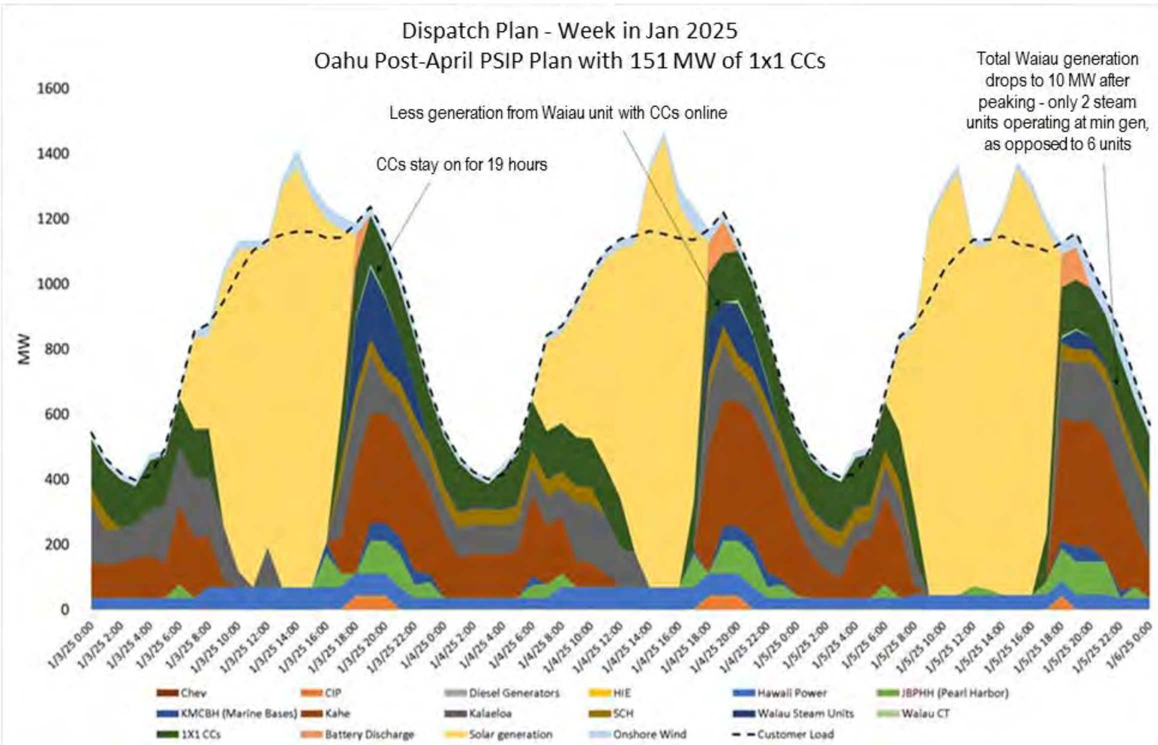


Figure 7: Dispatch plan with 151 MW of 1x1 combined cycle generators, January, 2025.

Figure 7 shows the dispatch plan for the same week with 151 MW of 1x1 CCs included (shaded dark green). Compared to the plan without the CCs, the utilization rate of the Waiu steam units drops considerably. The Waiau steam units do come online for peaking hours, but less of them do; thus they incur less heat rate penalties. Moreover, the CCs displace the generation of the Waiau combustion turbine (CT) generator (represented by the light green sliver above the Waiau steam units) during peak conditions, as they are more efficient than CTs in providing flexible generation.

In sum, there is a compelling need to have a more flexible fleet to address the imbalance between supply and load that comes with high intermittent renewable penetration. Without the flexible thermal fleet, production costs will be significantly higher because a considerable amount of steam generators will be compelled to come online for a relatively short duration during peaking conditions, and then remain running at minimum generation for a substantial block of hours when their generation is no longer necessary.

3.2. Optimal Thermal Generation Mix

Figure 8 compares the total costs for thermal generation of three thermal mixes for Oahu: (1) the optimized thermal mix plan developed by Ascend, (2) a thermal mix that does not upgrade Oahu's thermal fleet, (3) the Post-April PSIP Plan thermal mix. Ascend's optimal thermal mix calls for the addition of 1 CC in 2025, 1 internal combustion engine (ICE) in 2025, 2 ICEs in 2026, 1 CC in 2027, 1 ICE in 2030, and 1 ICE in 2035. The Oahu Post-April PSIP Plan adds 5 151 MW CCs in 2025, 2027, 2030, 2032, and 2035 respectively. The CC capacities are 151 MW, while the ICE capacities are 16.8 MW.

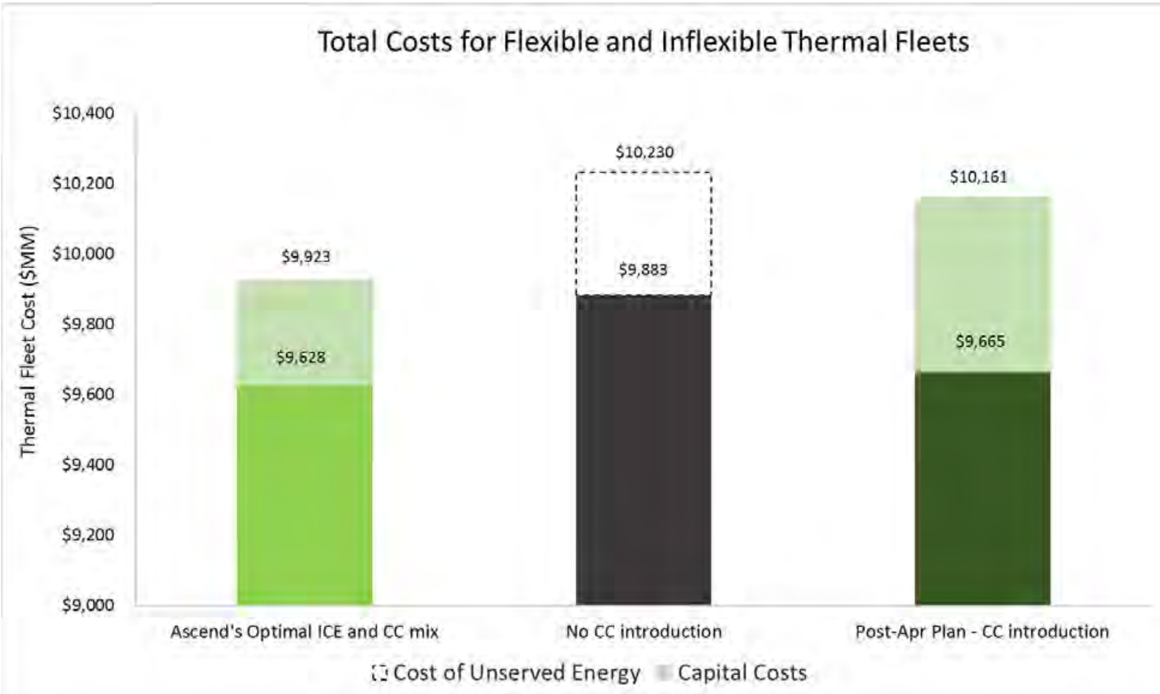


Figure 8: Total costs for flexible and inflexible fleets.

The lower bar in each plan represents the total production costs of each thermal mix. Since there are additions to the thermal fleet in both the Post-April PSIP Plan thermal mix and the Ascend thermal mix, the capital costs for those additions are included as well in the total costs, as indicated by the light green bar stacked on top of production costs. Ascend also analyzed the level of resource adequacy provided by each of these thermal mixes, and though the thermal mix without upgrades (represented by the middle bar) has no capital costs, such a thermal mix fails to meet resource adequacy standards, placing Oahu at substantial risk for power outages. Thus, penalties of $10,000 per forecasted MWh short were added to the total costs. Relative to the thermal mix with no upgrades to the fleet, the Ascend thermal mix provides $342 M less in total costs, while Post-April PSIP Plan's thermal mix provides $69 M less in total costs.

3.3. Introducing Imperfect Foresight

The thermal generation costs presented in the prior section were calculated under conditions of perfect foresight. Perfect foresight entails that the production cost model can see the future states of load, solar generation and wind generation, and decide accordingly how to employ thermal generation units. In reality, however, operators do not have this information; thus, to be prepared for any sudden dips in renewable generation or spikes in load, operators tend to leave thermal generators online at minimum generation for longer stretches. PowerSimm's modeling of imperfect foresight accounts for such operating practices. Figure 9 below compares the results of each thermal mix with perfect and imperfect foresight.

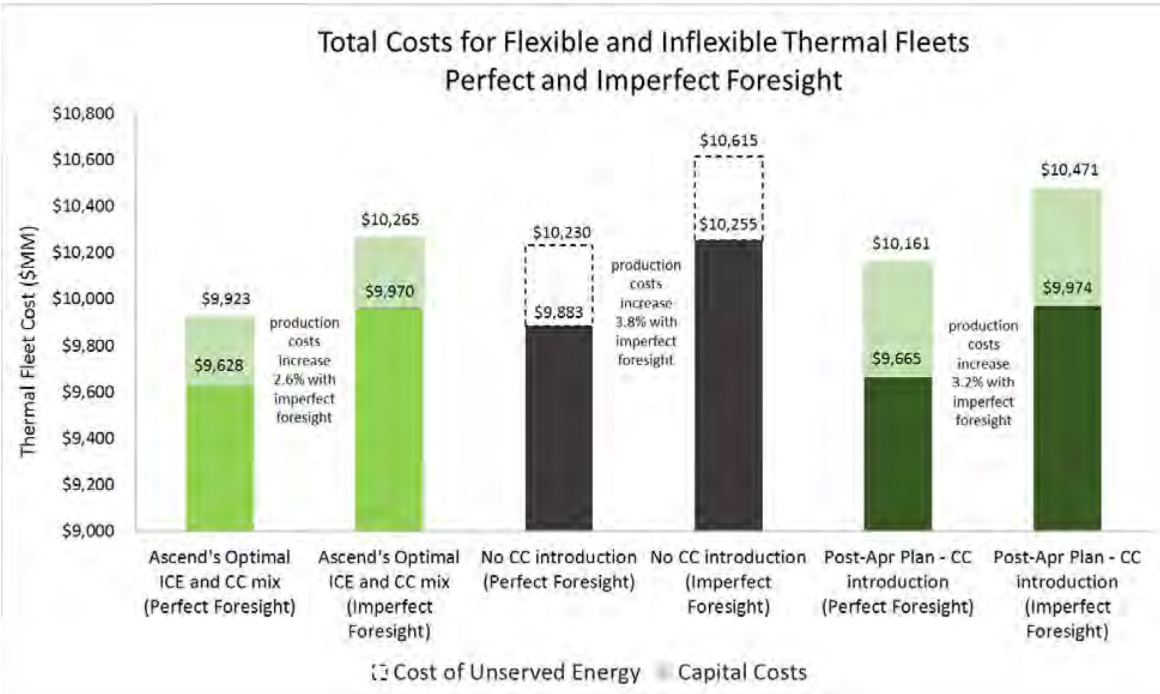


Figure 9: Total costs for flexible and inflexible fleets with perfect and imperfect foresight.

With imperfect foresight, costs increased by the greatest percentage for the thermal mix with no upgrades. The thermal fleet without any introduction of ICEs or CCs incurs the most additional costs with imperfect foresight because its relatively inflexible generators must stay online at minimum generation for longer periods of time. On the other hand, the flexible fleets are able to start up and shut down, and ramp up and ramp down at much faster rates, enabling them to run at more efficient heat rates under conditions of imperfect foresight.

Ascend's optimal thermal mix has a smaller increase in costs with imperfect foresight (2.6%) compared with the Post-April PSIP Plan's thermal mix (3.2%). Ascend's optimal thermal mix contains two CCs and 5 ICEs, while the Post-April PSIP Plan's mix contains 5 CCs. ICEs are the more flexible generator; thus the prevalence of them in Ascend's fleet causes the lower increase in costs with imperfect foresight.

4. Ascend-Developed Plans and Final Comparisons of Each Island's Plans

To update and improve upon the three Post-April PSIP Plans, Ascend used PowerSimm to develop new, optimized plans. In the new plans developed by Ascend, one of the main features is the inclusion of load-shifting batteries. Thus, this section will first demonstrate the benefits of including load-shifting batteries in energy portfolios with high levels of renewables. Second, this section will discuss resource adequacy, highlighting the need to maintain adequate thermal reserves in the case of an extreme event. Third, this section will present the details of PowerSimm's analysis of the Ascend-developed plans for each island system, as well as a comparison of these plans to the non-Ascend plans.

4.1. Load-Shifting Batteries

One of the main challenges of shifting to a 100% renewable portfolio is the intermittent nature of renewable generation. For instance, a renewable portfolio with a large amount of solar will generate excess power during the day, but too little at night. Load-shifting batteries provide a means to store that excess day-time generation and discharge the power at night. In this way, when shifting to a 100% renewable portfolio, batteries become a crucial and cost-effective tool for meeting load. This subsection will further elucidate the advantages of utilizing load-shifting batteries; then it will present the assumptions Ascend made regarding the inclusion of load-shifting batteries in the PowerSimm model.

4.1.1. The Case for Batteries

To demonstrate the advantages of including load-shifting batteries in portfolios with a large percentage of renewables, the following figures show PowerSimm simulation results of battery charge/discharge cycles in relation to customer load, renewable generation, and thermal generation for two different time periods for a single stochastic simulation. These two time periods were specifically chosen to demonstrate times when there are sufficient renewables and battery capacity to minimize the need for thermal generation. However, even at these levels of renewables and batteries, there are still times when there is insufficient renewable energy (due to, for example, extended periods of light winds or cloudy weather) to eliminate the need for thermal generation.

Figure 10 shows a time (May 2045) when there is more than adequate renewable generation. In this figure, there are prolonged periods where renewable generation far exceeds the customer load. During these times, batteries can be charged to minimize dump energy. However, once the batteries reach their capacity, charging stops and any additional renewable energy is "dumped", or not utilized. PowerSimm modeling recognizes that capturing all dump energy is not the optimal solution. Building excessive battery capacity at some point will cost more than the value of the energy it is designed to store.

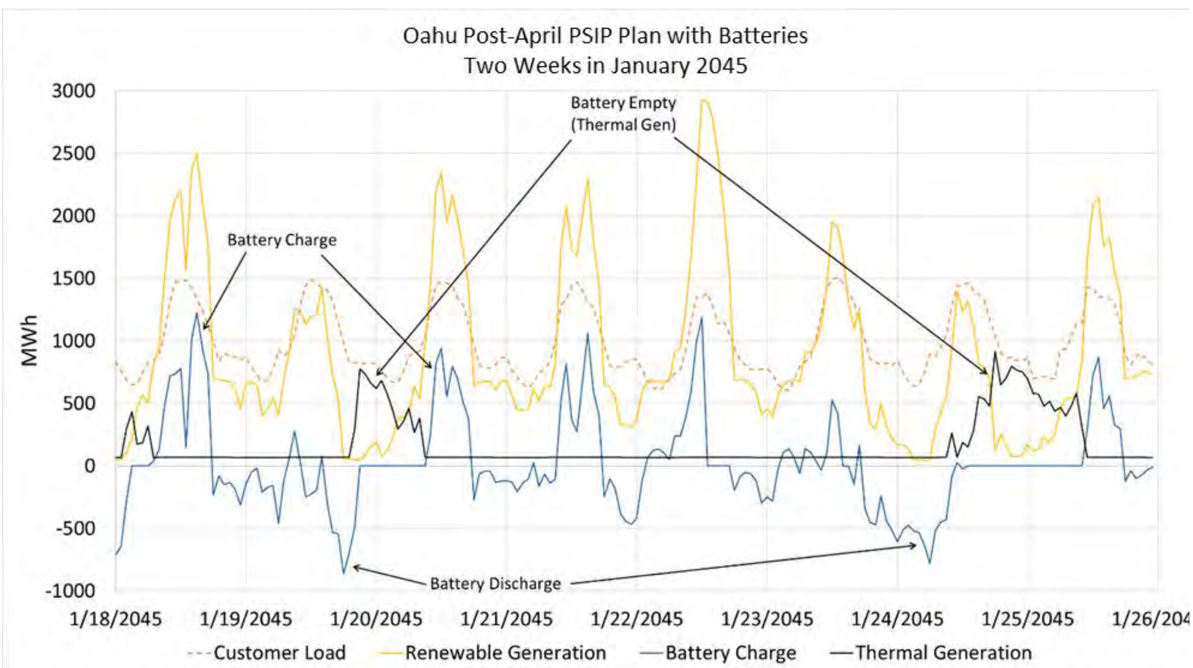


Figure 10: One stochastic simulation for a two-week May 2045 with 7,000 MWh batteries.

If it were not for the load-shifting batteries added to this portfolio, a significant amount of the energy generated by solar renewables during the day would be wasted since there would be no mechanism to store this energy. Moreover, the stored energy is then utilized when solar generation is not sufficient to meet load. This is indicated in Figure 10 when the battery charge is negative, that is, discharging its stored energy in order to meet net-load. Without load-shifting batteries, there would be insufficient renewable energy resources whenever solar stops generating at night, thus requiring thermal generation to meet customer demand. Not only would this thermal generation in 2045 require burning expensive biofuels, but it would also require expensive plant startups or running power plants at a sub-optimal generation level to prevent startups and shutdowns.

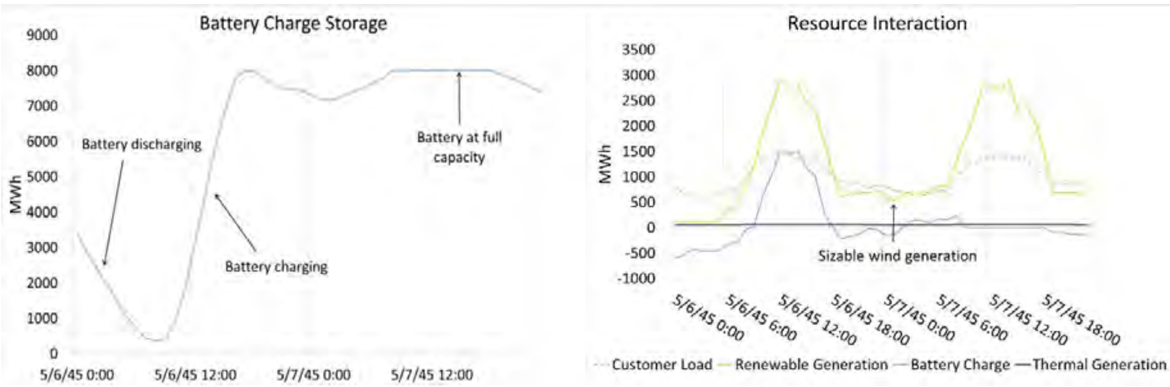


Figure 11: Comparison of battery dynamics for May 6th and 7th, 2045. The diagram to the left indicates the battery state of charge. The diagram to the right indicates the resource interactions between renewable energy (yellow line), customer load (red dashed line), thermal generation (black line) and batteries (blue line).

Figure 11 provides a more in-depth look at battery dynamics on May 5th and 6th, 2045. As seen in the right diagram, renewable generation is very low from midnight to sunrise on May 6th; thus the battery has to discharge. In the left diagram, the battery discharge is presented by the decreasing slope, indicating that the battery discharged around 3,000 MW. When solar generation begins to exceed customer load at approximately 10:00 a.m. (see right diagram), the battery starts to charge up to its full capacity of 8,000 MWh. There is more wind generation during the night of the 6th and 7th than the prior night. Thus the battery has to discharge relatively little of its stored energy, and even before sunrise it begins to recharge to full capacity. As a result, when solar generation comes online on May 7th, the battery absorbs only a minimal amount of the generation in excess of load, and then ceases to charge during the period in which solar generates the most dump energy. The left diagram confirms that the battery barely charges because it is already at full capacity.

Figure 12 shows the resource interactions between thermal generation, renewables, and batteries in a winter month (January, 2045). When renewable generation exceeds load, batteries are able to absorb the excess energy by charging. When renewable generation is less than load, batteries can help meet load by discharging. However, there are periods when batteries are totally depleted and thermal generation must ramp up to meet load. These scenarios are typically attributable to weather conditions that are either cloudy (minimal solar generation) or still (minimal wind generation). During such time periods, biodiesel must be consumed to provide adequate generation to meet load.

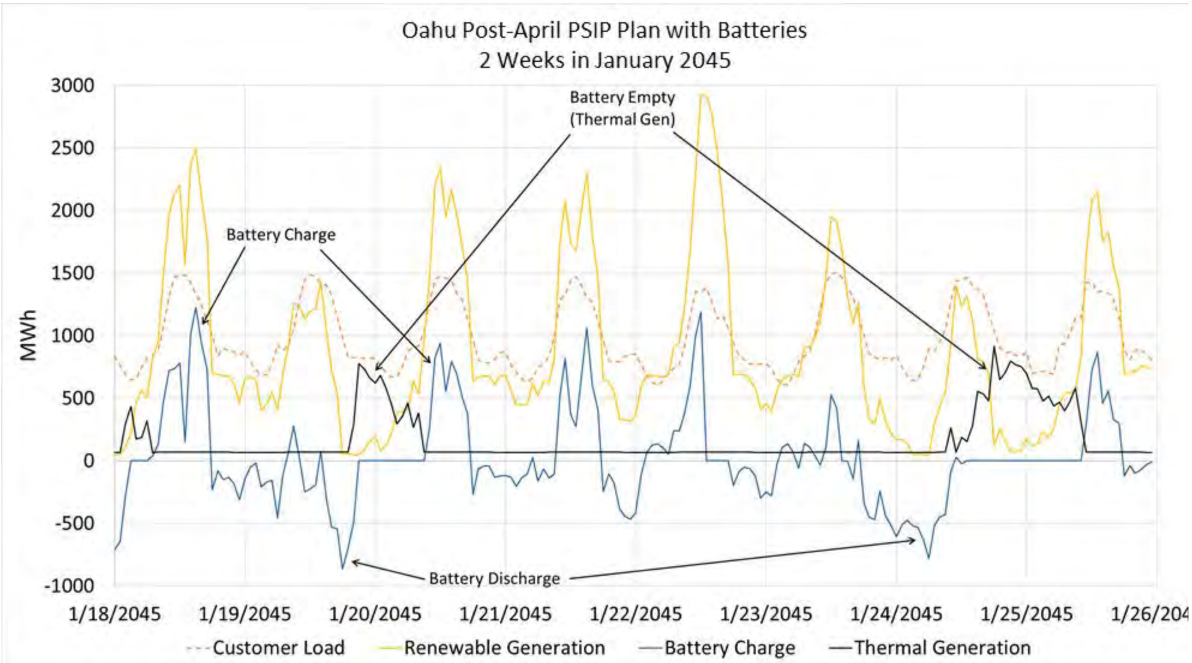


Figure 12: One stochastic simulation for January 2045 with 8,000 MWh batteries.

Figure 13 provides a more detailed view of the dynamics between renewables, batteries and thermal generation for January 24th and 25th, 2045. On January 24th, there is not enough solar generation to meet load, and very little wind generation during the night. Thus the load-shifting battery must discharge the rest of its stored energy early in the day, and thermal generation must come online, eventually serving over 80% of the load during the night of the 24th and 25th. However, during the day of the 25th, renewables exceed customer load, enabling batteries to charge.

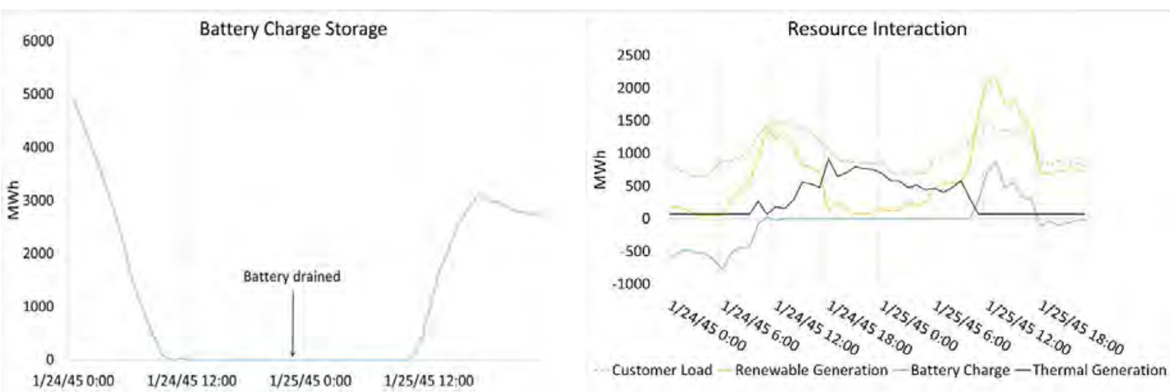


Figure 13: Comparison of battery dynamics for January 24th and 25th, 2045. The diagram to the left indicates the battery state of charge. The diagram to the right indicates the resource interactions between renewable energy (yellow line), customer load (red dashed line), thermal generation (black line) and batteries (blue line).

Thus, by 2045 load-shifting batteries do not eliminate thermal generation, but they do minimize the need for it. Thermal generation will be especially crucial during extended periods of low renewable generation (e.g. during a series of cloudy days where batteries are not able to recharge with adequate solar generation). Moreover, even during periods where there is sufficient renewable generation to meet load, thermal generation is always running at a steady, though minimal level. To economically meet the thermal generation requirements under conditions of higher intermittent renewable penetration, Oahu would have to (1) update its existing thermal fleet with flexible thermal units, as detailed earlier in section 3, and (2) maintain sufficient thermal generation capacity in order to ensure resource adequacy. This second component will be gone over in section 4.3.

Load-shifting batteries provide a cost-effective way to smooth over the variability of intermittent renewable generation by storing excess energy, also referred to as dump energy, that would otherwise be lost. Below, Figure 14 addresses this point directly by showing the amount of dump energy per year with and without batteries. The Oahu Post-April PSIP Plan optimized with batteries reduces dump energy by approximately 120 GWh in 2025, and by over 400 GWh in 2040.

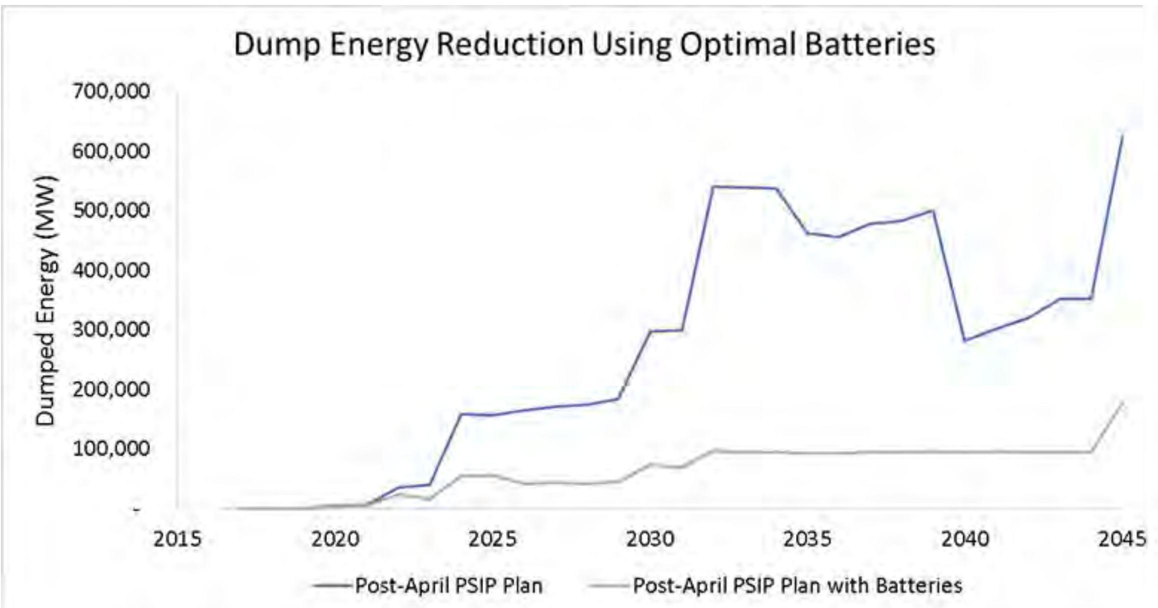


Figure 14: Dump energy for the Oahu Post-April PSIP Plan without batteries vs. with batteries

To summarize, the inclusion of load-shifting batteries in portfolios with high levels of renewables has substantial advantages. Load-shifting batteries can store large amounts of excess renewable energy generated during the day (dump energy that would otherwise be lost) and discharge that energy to meet load at times when renewable generation cannot meet load. However, though load-shifting batteries mitigate the need for thermal generation, they do not entirely eradicate this need.

4.1.2. Battery Assumptions

While including batteries in the PowerSimm modeling framework, Ascend made a series of assumptions about load-shifting batteries. First, Ascend assumed a 15-year lifetime for load-shifting batteries. Second, because batteries can be refurbished, Ascend assumed that the value of a battery at the end of its lifetime is 50% of the install cost at that time. Third, assuming an 8% interest rate and that battery installation costs from 2045 and beyond remain unchanged at $306/KWh, Ascend calculated the effective installation cost as follows:

$$EIC_t = IC_t - \frac{1}{2} PV(IC_{t+15}, 8\%)$$

Where EIC is the effective installation cost for a particular year, IC is the installation cost for a particular year, and PV is the present value function in Excel. Using this method, Ascend calculated the effective installation cost (EIC) for each year using battery installation costs (IC) provided by the Companies in the April 2016 PSIP filing. These costs for each year are shown in Table 4 below:

Year	Install Cost ($/KWh)	Effective Install Cost ($/KWh)	Year	Install Cost ($/KWh)	Effective Install Cost ($/KWh)
2016	660	607	2031	343	295
2017	615	562	2032	338	290
2018	565	513	2033	333	286
2019	524	472	2034	329	282
2020	487	436	2035	326	278
2021	461	411	2036	323	275
2022	440	390	2037	320	272
2023	422	372	2038	317	270
2024	406	357	2039	315	268
2025	393	344	2040	313	266
2026	382	333	2041	312	264
2027	372	323	2042	310	262
2028	363	315	2043	309	261
2029	355	308	2044	307	260
2030	349	301	2045	306	258

Table 4: Cost and Effective Cost of battery installation by year

Ascend also assumed that, to prevent damage from occurring, load-shifting batteries will never discharge below 20% of their capacity. To account for this assumption, there was a 20% adder included in the capital costs of batteries. However, it is important to note that the battery buildout plans shown in the following subsections show the *functional* battery capacity, that is, the battery capacity that can fully discharge. The *actual* battery capacities, which determine the capital costs, are always 20% greater than the *functional* battery capacities, which are shown in the figures below.

All of these battery assumptions were used across all new plans that include load-shifting batteries.

4.2. Marginal Renewable Resource Analysis

PowerSimm was also used to conduct a marginal analysis of an additional MW of renewable generation for the Oahu Post-April PSIP Plan. For these calculations, 1 MW of renewable generation was added to the Oahu portfolio to determine the effective cost of the additional power from each 1 MW addition. The resulting levelized cost of power (i.e. cost of power inclusive of both variable and capital costs over the lifetime of the generation unit) was then compared to the levelized cost of power from traditional thermal generation assets available in the Oahu portfolio. The results from this analysis are shown in Figure 15.

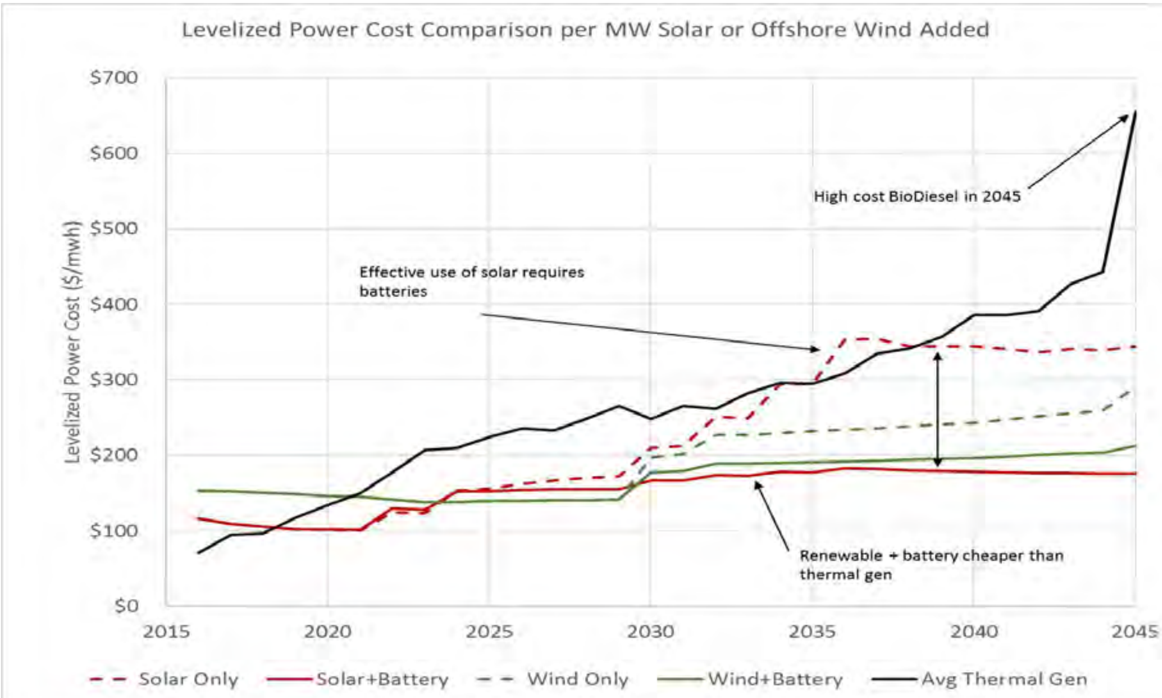


Figure 15: Compares levelized cost of different types of generation with and without batteries

Figure 15 shows that renewables become more cost-effective early on relative to the variable cost of thermal generation, excluding all fixed costs. Load-shifting batteries combined with solar start adding significant value in 2025, by capturing dump renewable generation and serving to reduce the cycle demand on thermal generation. Load-shifting batteries combined with wind generation begin to add value by 2030, when offshore wind generation comes online. That being said, load-shifting batteries only account for battery benefits on an hourly scale. On the other hand, regulation batteries, which incorporate battery usage on a minutely scale, provide cost savings much earlier on.[3] By 2035, adding renewables without adding battery capacity for storage does not make economic sense, especially for solar. Large differences upwards of $100 per MWh can be realized by simply adding sufficient battery storage along with solar. Thus the ability of Oahu to realize high renewable generation rates become a function of battery costs continuing to decline.

Additionally, Figure 15 shows that solar combined with batteries and wind combined batteries provide similar costs through time. Ascend's analysis has solar becoming slightly cheaper than wind after 2030; yet which resource will actually provide cheaper power in the future is an open question. If there is a steeper decline in the costs of offshore wind, then it could be more cost-effective to opt for further wind generation, diminishing to some extent the need for batteries, as a MW of wind generation requires about half the storage level as a MW of solar generation. If there is a steeper decline in the costs for batteries, the combination of solar generation and batteries would become even more appealing.

[3] See section 5.2.2 for more on regulation batteries.

4.3. Resource Adequacy

Due to the intermittency of renewable resources, there is always the potential for extended periods of still and/or cloudy weather that severely curtails solar and wind generation. Under such extreme weather conditions, the energy system has to be able to continue to meet load reliably. Central to maintaining resource adequacy under all weather conditions is recourse to sufficient dispatchable generation capacity.

This section will present probability distributions of thermal generation in 2045, as produced over numerous weather simulations, for both the Oahu Post-April PSIP Plan and the Oahu Post-April PSIP Plan with Batteries. Then, this section will assess the Loss of Load Probability (LOLP) (i.e. the probability of outages due to load exceeding supply) for both Oahu and Maui under the Post-April PSIP Plan, the Ascend Plan, and the E3 Plan.

Figure 16 displays the probability distribution of thermal generation in 2045 under the Oahu Post-April PSIP Plan.

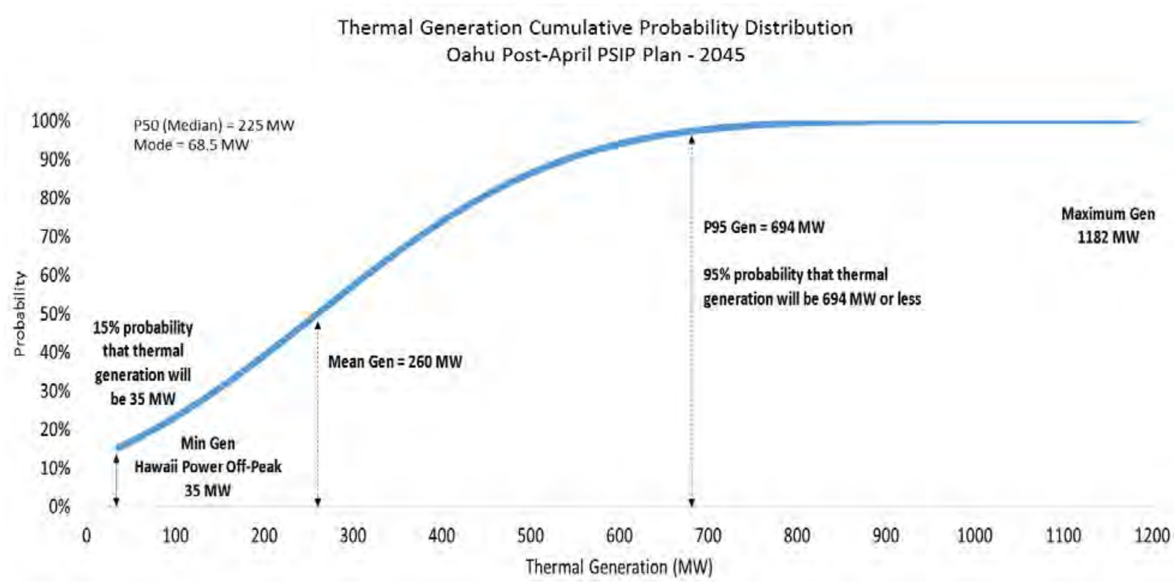


Figure 16: Probability distribution of thermal generation requirements over distinct weather simulations for the Oahu Post-April PSIP Plan (without optimized batteries).

In 2045, the amount of thermal generation most often required (i.e. the mode) is forecasted to be 68.5 MW. There is, however, also 1% chance in 2045 that Oahu will confront weather conditions requiring 924 MW of thermal generation, and the maximum amount generation Oahu will be expected to serve is 1182 MW, which is 116% of average load for the year. Such extreme scenarios are outliers, but nevertheless Oahu would have to be prepared to meet such scenarios.

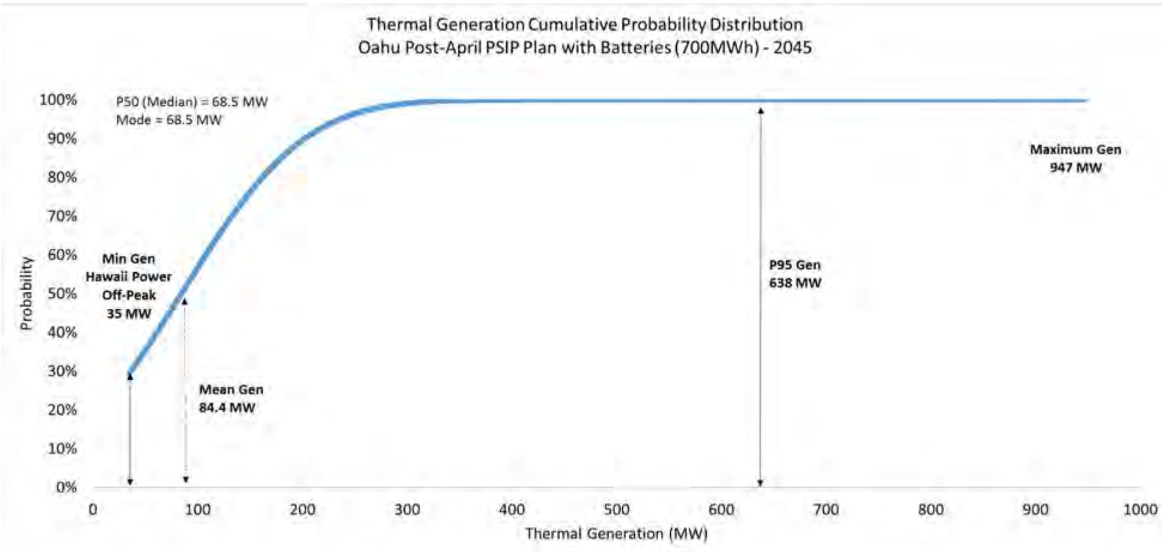


Figure 17: Probability distribution of thermal generation requirements over distinct weather simulations for the Oahu Post-April PSIP Plan optimized with 7000 MWh of batteries.

As Figure 17 shows, the addition of 7000 MWh of batteries to the Oahu Post-April PSIP Plan shifts the probability distribution of thermal generation to lower values. With 7000 MWh of batteries, the average amount of thermal generation required in 2045 drops by 68%, from 260 MW to 84.4 MW. The maximum thermal generation required also shrinks from 1182 MW to 947 MW. However, compared to the shrinkage in the average amount of thermal generation required (68%), the reduction in the maximum amount of thermal generation required is not as dramatic (20%). The limited reduction of maximum thermal generation under the Post-April PSIP Plan with Batteries alludes to the limitations of batteries in extreme weather scenarios. If there is an extended weather period with extremely low wind and solar generation, batteries would be unable to recharge from renewable sources. If batteries were to charge, they would do so from thermal generation in excess of load. Thus in such scenarios sufficient thermal reserves would have to be in place to serve the overwhelming majority of load.

Figure 18 and

Figure 19 further emphasize the variability of thermal generation requirements. Ascend ran 20 simulations of thermal generation requirements over a two-week period in May, 2045. Figure 18 and

Figure 19 display the 5th percentile, average, and 95th percentile of the forecasted amount of thermal generation required for the Oahu Post-April Plan and the Oahu Post-April Plan with Batteries (7000 MWh) respectively.

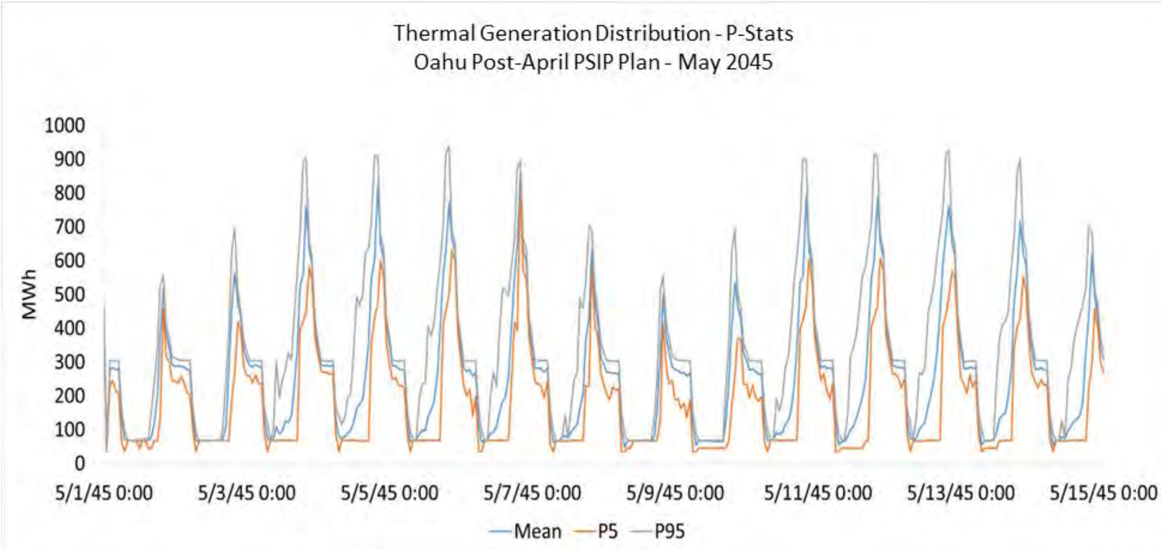


Figure 18: Thermal generation disitribution over distinct weather simulations for two-week period in May, 2045 for the Oahu Post-April PSIP Plan (without optimized batteries).

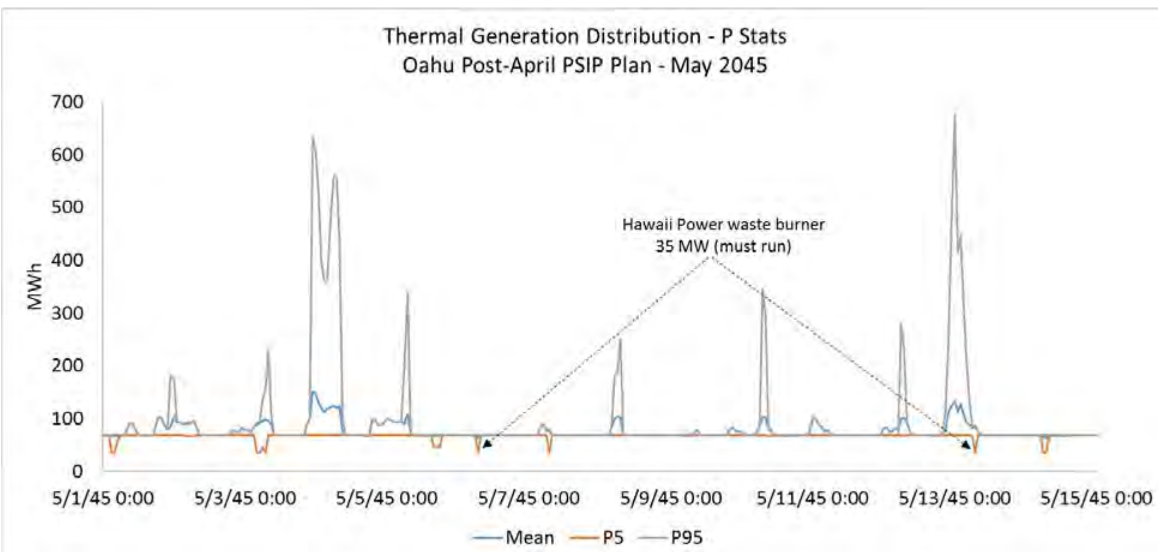


Figure 19: Thermal generation distribution over distinct weather simulations for two-week period in May, 2045 for the Oahu Post-April PSIP Plan optimized with 7000 MWh of batteries.

The blue line signifies the average thermal generation requirements when accounting for all the weather scenarios analyzed. The orange P5 line represents the mild weather scenarios that are more favorable to renewable generation (i.e., 5% of the scenarios evaluated have less thermal generation required). The gray P95 line represents extreme weather scenarios that are unfavorable to renewable generation (i.e., 95% of the scenarios examined require less thermal generation). A comparison of Figure 18 and

Figure 19 reveals that batteries substantially reduce the amount of additional thermal generation. Without batteries, large amounts of thermal generation are required on a daily basis, irrespective of the weather scenario. On the other hand, with 7000 MWh of batteries, the average amount of thermal generation required remains for the majority of the time around 68.5 MW.

Nevertheless, though the need for a significant amount of thermal generation is curtailed by batteries, there are still extreme weather scenarios to be found in May 2045 where the majority of load will have to be served by thermal generation. In Figure 19, the gray P95 line represents these scenarios, spiking up to 750 MW in some instances.

Figure 20 shows that in a winter month such as January the potential for such spikes in thermal generation increases in frequency and magnitude. For this two-week period in January 2045, there are 5 instances where the extremes scenarios require thermal generation to ramp up to 500 MWh or more, compared to the two-week period in May 2045 found in Figure 19, where there were only 2 such instances. The increase in the frequency and magnitude of price spikes follows from the variability in solar generation during winter months.

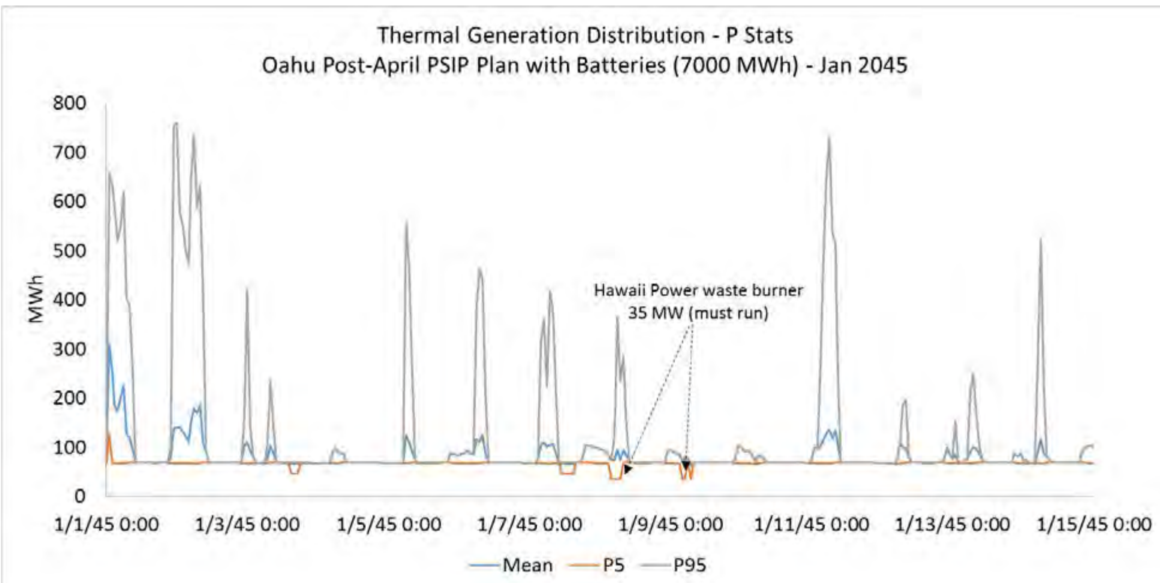


Figure 20: Thermal generation distribution over distinct weather simulation for two-week period in January, 2045 for the Oahu Post-April PSIP Plan optimized with 7000 MWh of batteries.

In sum, even with high levels of wind and solar generation, Oahu must maintain thermal generation capacity at levels where it can serve the majority of load in order to maintain resource adequacy. Even if thermal generation is rarely utilized at high capacities, the guarantee of dispatchable energy in periods with low intermittent renewable generation is essential for meeting load reliably. Though load-shifting batteries significantly curtail the need for thermal generation, they do not completely eliminate this need.

4.3.1. Loss of Load Probability: Oahu

Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE) calculates the expected duration of outages and the expected shortfall in generation per year given a system's available resource capacity and forecasted load. LOLP provides an important indicator of a system's level of resource adequacy.

Ascend assessed LOLP for the Oahu Post-April PSIP Plan, Ascend Plan, and E3 Plan. To measure LOLP, Ascend calculated under each plan the expected Loss of Load Hours (LOLH) per year, i.e., the amount of hours when load exceeds supply. Ascend also calculated the shortfall of MW per year. The LOLP analysis uses an advanced integrated simulation framework that captures the joint probability of load and intermittent renewable generation over numerous simulated weather conditions. Because Ascend applies an integrated simulation framework of renewables, load and thermal generation outages, resource deficits can be examined at the 5th, mean and 95th.

NERC's reliability standard for planning in a large integrated power grid is an LOLH of 2.4 hours per year, which corresponds with a total of 24 hours of outages over 10 years.

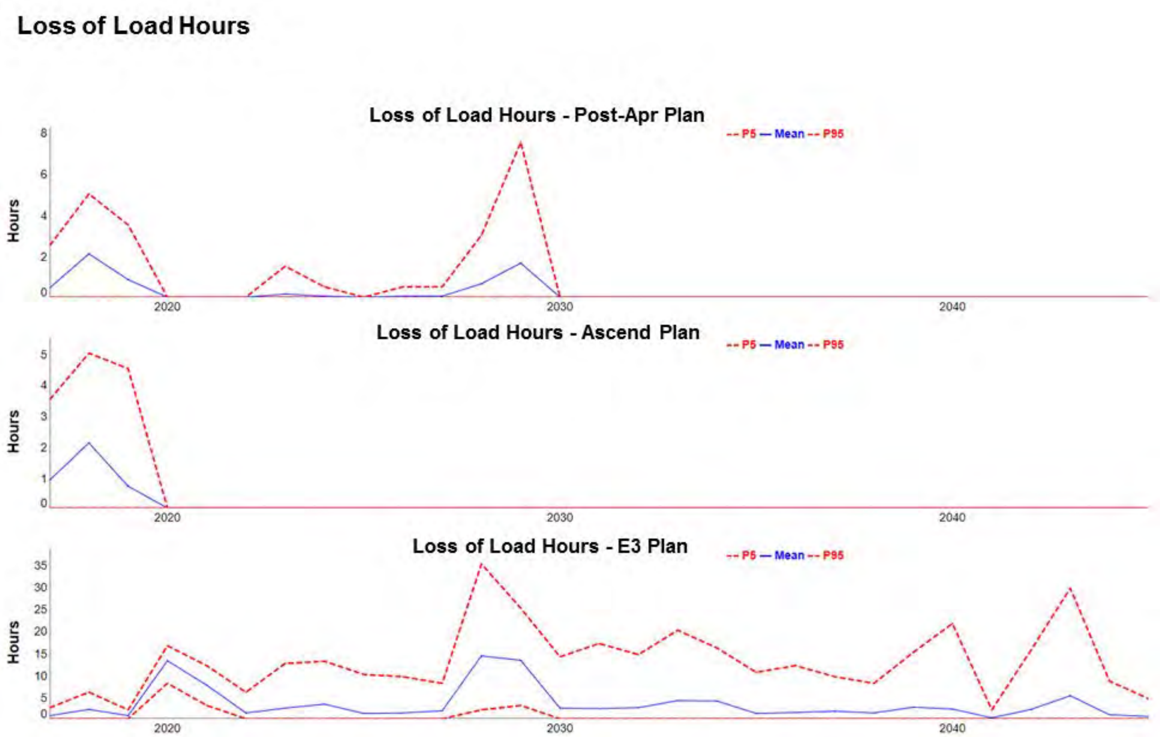


Figure 21: Loss of load hours from 2017 to 2045 for the Oahu Post-April PSIP Plan, Ascend Plan, and E3 Plan.

Figure 21 presents a comparison of the Loss of Load Hours for Oahu under the Post-April PSIP Plan, the Ascend Plan, and the E3 Plan. The mean represents the average hours of outages per year from all the simulations examined. The confidence interval specified by the P5 and P95 endpoints indicate the range of possible hours the portfolio could be short in a given year with a 90% confidence that the true value is within this range.

For the Oahu Post-April PSIP Plan, the average LOLH never exceeds 2.4 hours. However, the P95th bound indicates 3 hours for 2028 and 7.5 hours for 2029 where load exceeds capacity. The increase in expected LOLH results from the retirement of the Kahe 5 and 6 units in 2028. With the introduction of offshore wind in 2030, the LOLH drops to 0 hours from 2030 onwards.

For the Oahu Ascend Plan, the LOLH is relatively similar to the Post-April Plan through 2020. After 2020, however, the Ascend Plan has no expected LOLH. The Ascend Plan adds significantly more renewable generation and batteries than the Post-April PSIP Plan, placing Oahu in a better position to ensure a reliable power supply.

Out of all the plans evaluated, the Oahu E3 Plan has the lowest degree of resource adequacy. From 2017 to 2045 the mean LOLH exceeds 2.4 hours for 40% of the years, and the P95th exceeds 2.4 hours for 96% of the years. The E3 Plan assumes that all steam units will be retired by 2022, and the only update of the thermal fleet contained in the plan is in 2045. The E3 Plan calls for significant levels of batteries, which does assist in providing a secure supply; yet batteries cannot make up for such low levels of thermal generation, which undermine Oahu's ability to furnish enough capacity to meet load under all conditions.

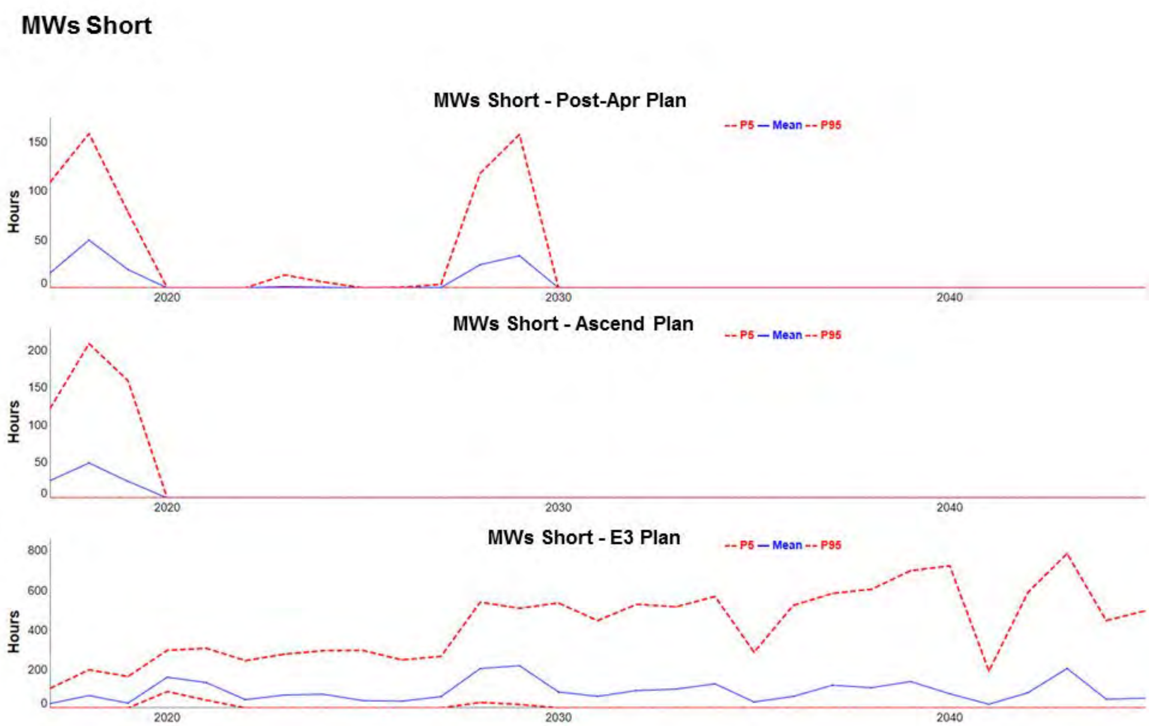


Figure 22: MWs short for Oahu's Post-April PSIP Plan, Ascend Plan, and E3 Plan.

Figure 22 indicates resource adequacy by displaying the expected shortfall of MW per year for each plan. For the Oahu Post-April PSIP Plan, from 2017 to 2019 and from 2028 to 2030 the 95th confidence bound for the shortfall in generation reaches 150 MW, while for the rest of the years there is no or only a negligible expected shortfall in generation. For the Oahu Ascend Plan, from 2020 onwards there is no expected shortfall in generation. For the Oahu E3 Plan, there are no years evaluated without expected shortages. The Oahu E3 Plan's highest mean value for MWs short over the years is 213 MW, which is over 4 times higher than the highest mean values for the Post-April PSIP Plan and the Ascend Plan.

Thus the LOLP results further bolster the conclusion that Oahu will continue to need thermal generation to serve load reliably. A plan such as the Oahu E3 Plan, which proposes early retirement of steam units and no significant updates of the thermal fleet, falls short in providing the necessary resource capacity to maintain the security of the power supply.

4.3.2. Loss of Load Probability: Maui

PowerSimm's analysis of the Maui Post-April PSIP Plan and the Maui Ascend Plan found no expected loss of load from 2017 to 2045 for these two plans. PowerSimm's analysis of the Maui E3 Plan, however, reveals the plan to fall short in meeting resource adequacy standards by considerable margins.

As shown in Figure 23 and Figure 24, the E3 Plan's average LOLH over the weather simulations examined ranges from 22 hours to 36 hours from 2020 onwards. Correspondingly, the E3 Plan's mean shortfall in MWs range from 150 MW to 170 MW from 2020 to 2045.

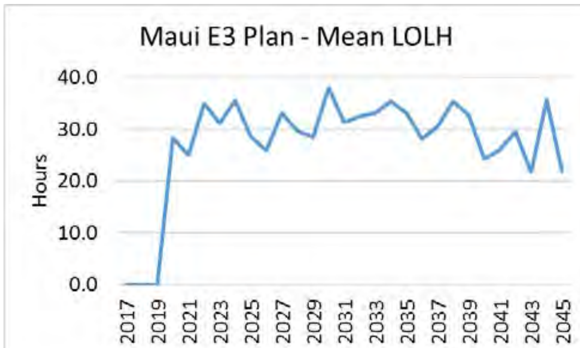


Figure 23: Average LOLH of Maui E3 Plan

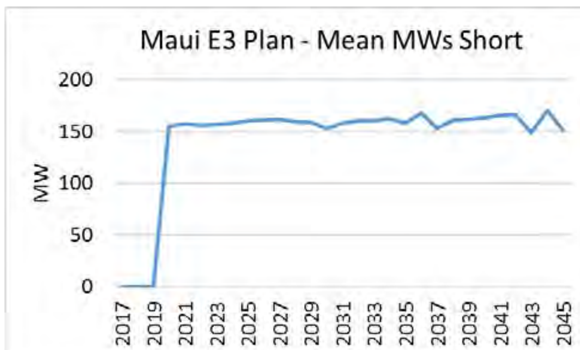


Figure 24: Average MWs short for Maui E3 Plan.

The E3 Plan's drastic increase in LOLH and MWs short in 2020 has two chief causes. Firstly, relative to the Maui Post-April PSIP Plan, the E3 Plan installs 75 MW less of solar capacity and 10 MW less of onshore wind capacity in 2020. Secondly, the E3 Plan retires the 106 MW Maalea CC plant in 2022. The Maalea plant is Maui's primary oil-based generation unit, and retiring this unit puts Maui in a position with very little thermal reserves, causing the island to be heavily dependent on renewable based generation. Thus, under weather conditions unfavorable to renewable generation, the Maui E3 Plan risks significant shortages.

4.4. Oahu Results and Optimized Plans

This subsection will detail the two new plans created by Ascend, the Post-April PSIP Plan with Batteries and the Ascend Plan. The Oahu Post-April PSIP Plan with Batteries was developed by optimizing the levels of batteries in the original plan. The Oahu Ascend Plan was developed by jointly optimizing solar generation, wind generation and batteries in the Post-April PSIP Plan. The end of this subsection will provide a comparison of the NPV portfolio costs of the two Ascend-optimized plans, as well as the Post-April PSIP Plan and the E3 Plan.

4.4.1. The Optimization of Batteries: Post-April PSIP Plan with Batteries

This plan is based on Oahu's Post-April PSIP Plan, from which Ascend has developed an optimized battery buildout plan for load-shifting batteries. The optimized battery buildout plan is indicated by the dashed green line in Figure 25 below.

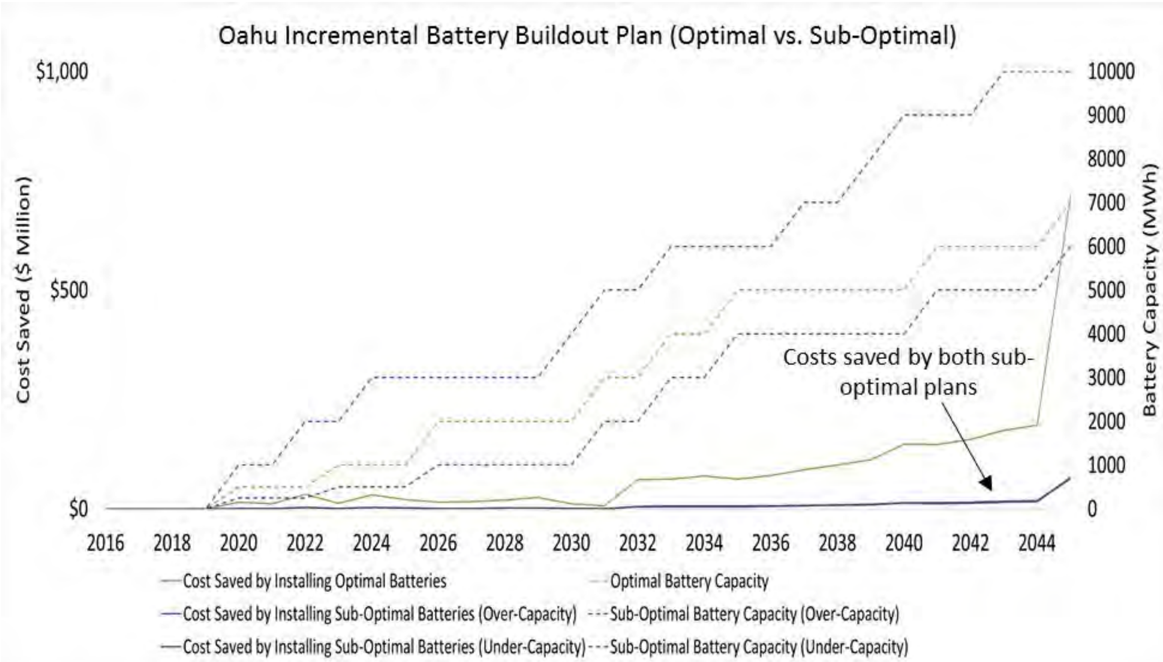


Figure 25: Comparison of two suboptimal battery buildout plans with optimal buildout plan for the Oahu Post-April PSIP Plan.

In Figure 25, three battery buildout plans are presented: the optimal plan, a plan with an over-installation of batteries and a plan with an under-installation of batteries. The dashed lines signify the battery capacity, while the solid lines signify the savings provided by each plan. Beginning in 2032, savings offered by the optimal plan grows steadily. In 2036, while the cost saved by the optimal buildout plan is around $100 M, the cost saved by the two suboptimal plans, which have lines stacked on top of each, are negligible. A comparison between the optimal installation of batteries and sub-optimal under-installation of batteries illustrates that by installing 1000 MWh less of battery capacity, savings drop drastically.

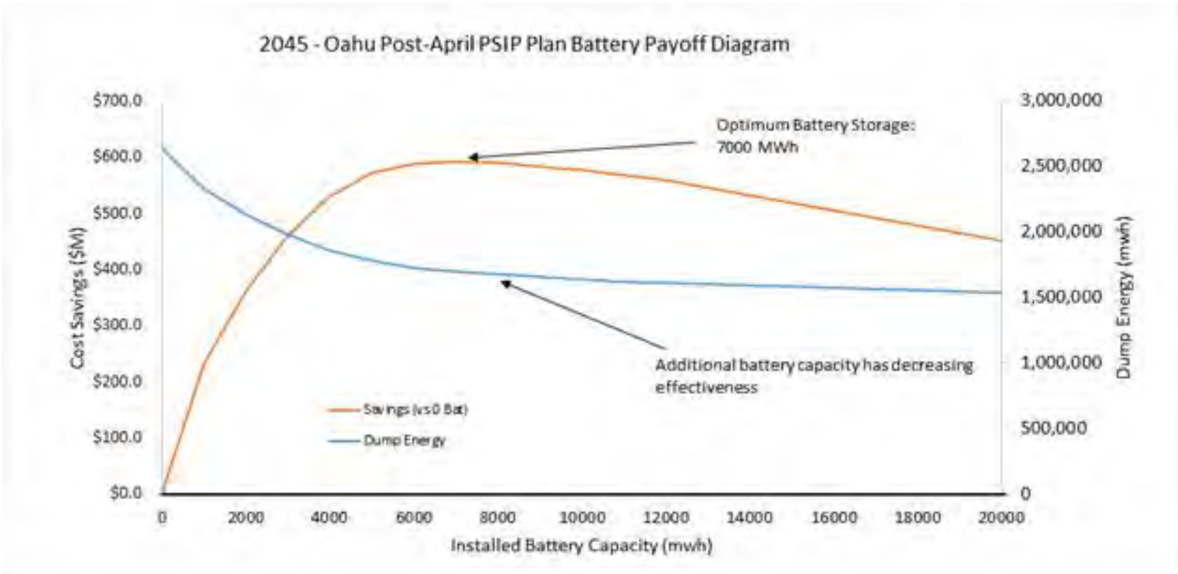


Figure 26: Battery Payoff Diagram for the Oahu Post-April PSIP Plan.

Figure 26 illustrates that additional battery capacity maintains positive marginal economic effectiveness until 7000 MWh. Beyond a capacity of 7000 MWh, the decreasing effectiveness of additional battery capacity in capturing additional dump energy causes savings to decrease.

4.4.2. The Optimization of Renewables and Batteries: The Ascend Plan

Ascend utilized the PowerSimm software to evaluate the concurrent changes needed to jointly optimize solar, wind, and batteries to come up with the renewable plus battery additions that would minimize the overall NPV of the selected portfolio. Sufficient PowerSimm analyses were performed to ensure the optimal mix of solar, wind, and batteries was identified. The existing renewable forecasts from the Oahu Post-April PSIP plan were designated as a starting point to determine how much additional wind, and solar, with corresponding battery storage, would be warranted to minimize overall theme costs.

Figure 27 displays the results from the co-optimization process that Ascend carried out to find the combination of offshore wind, utility solar, and batteries that minimize the NPV of Oahu's portfolio costs.

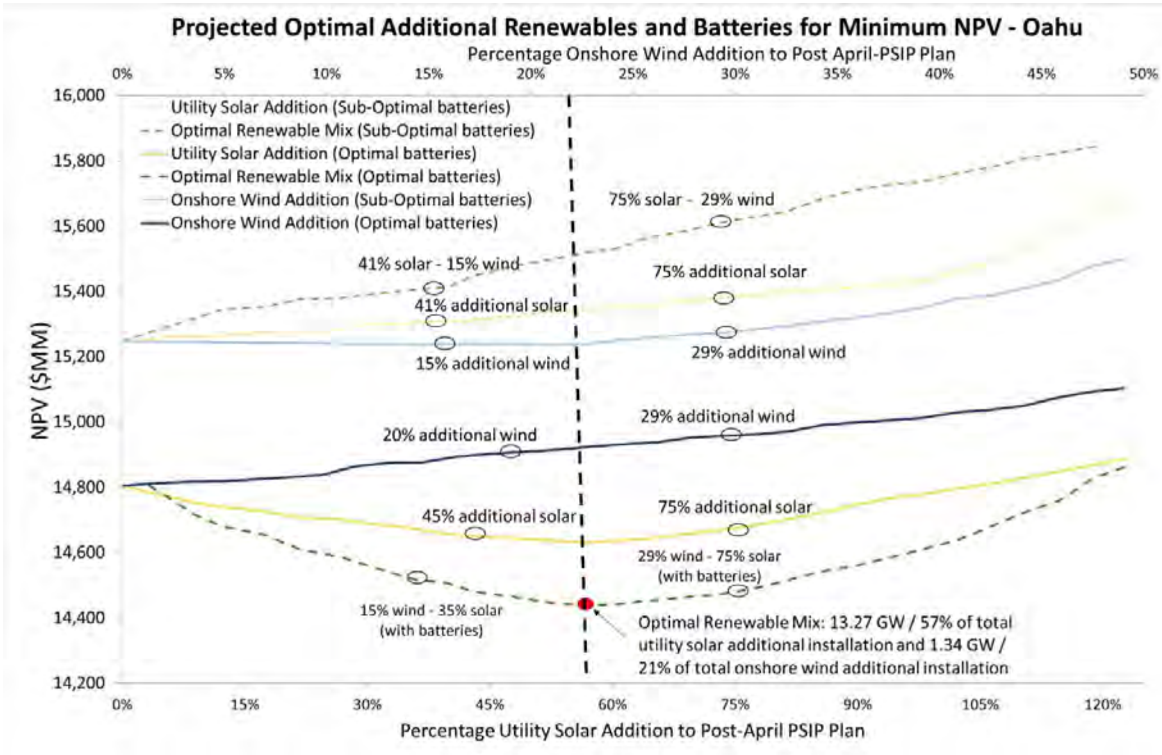


Figure 27: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries.

As shown in Figure 27, the "sweet spot" in the renewable plus battery additions was determined by analyzing a host of paths towards the 100% renewable goal by 2045. This "sweet spot" corresponds to the acceleration of the Post-April PSIP Plan utility PV buildout by 57% and the offshore wind buildout by 21%, in addition to an optimized battery buildout plan. This combination, which is Ascend's optimized plan, results in a NPV reduction of $809 M. It is important to note that to realize this optimal renewable plan, the addition of load-shifting batteries is *required*. Without batteries, as discussed earlier in this report, far too much energy is dumped at times of peak renewable generation, and far too little energy is available during the evening when solar renewables stop generating. Thus, accelerating the introduction of renewables goes hand in hand with the incorporation of load-shifting batteries. If batteries are not included in the plan, the additional renewable generation will actually substantially increase the NPV of Oahu's portfolio costs. With this in mind, the optimal battery buildout plan for the Ascend Plan is displayed below.

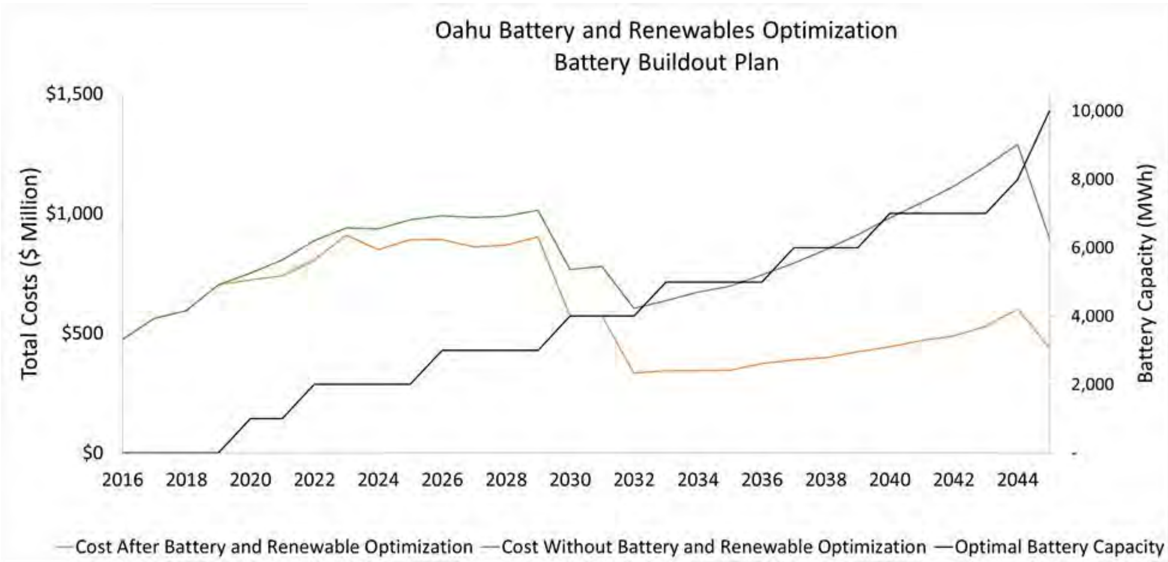


Figure 28: Battery buildout plan for the Oahu Ascend Plan. Battery capacities on the figure do not reflect the additional 20% required to prevent battery damage.

Compared to the Oahu Post-April PSIP Plan with Batteries, the Oahu Ascend Plan has a more aggressive battery buildout plan, calling for 3,000 MWh of battery capacity more than the Oahu Post-April PSIP Plan with Batteries. The higher level of renewables introduced by the Ascend Plan render higher battery capacity levels more economical.

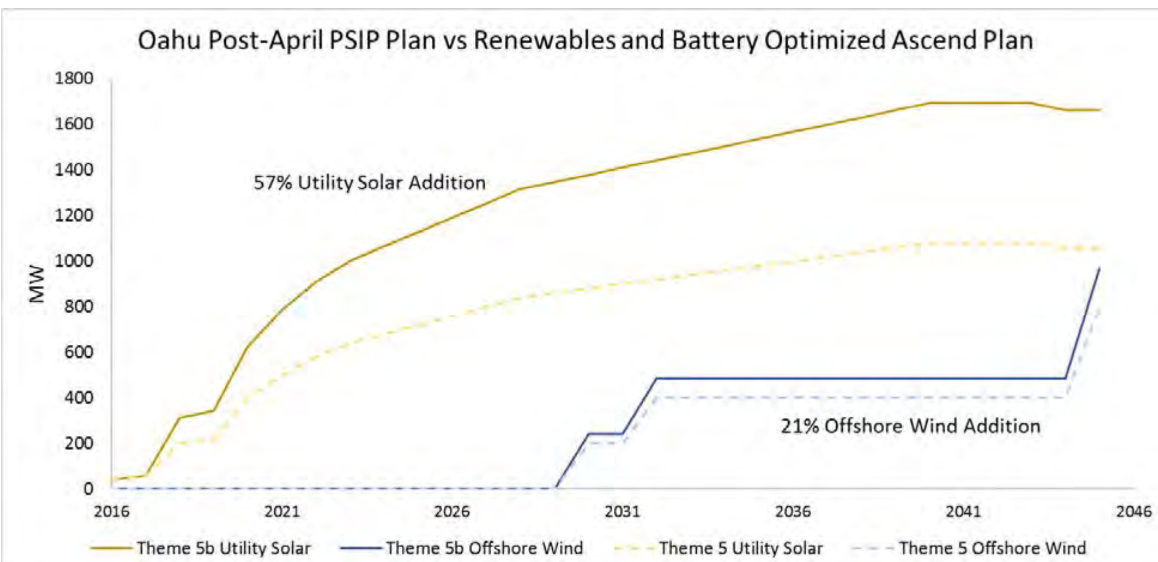


Figure 29: Comparison of renewable generation capacity between the Oahu Post-April PSIP Plan and the Oahu Ascend Plan.

Figure 29 presents the renewable additions of the Ascend Plan relative to the Post-April PSIP Plan. The Ascend Plan contains a 57% increase in utility solar and 21% increase in offshore wind. The marked additions of intermittent renewable generation in the optimized plan stem from the utilization of batteries. Batteries are crucial in rendering the additional intermittent renewable capacity economically beneficial. Solar generation, in particular, has a concentration effect during hours when the sun is shining most directly, resulting in significant amounts of excess energy, off which batteries are able to capitalize.

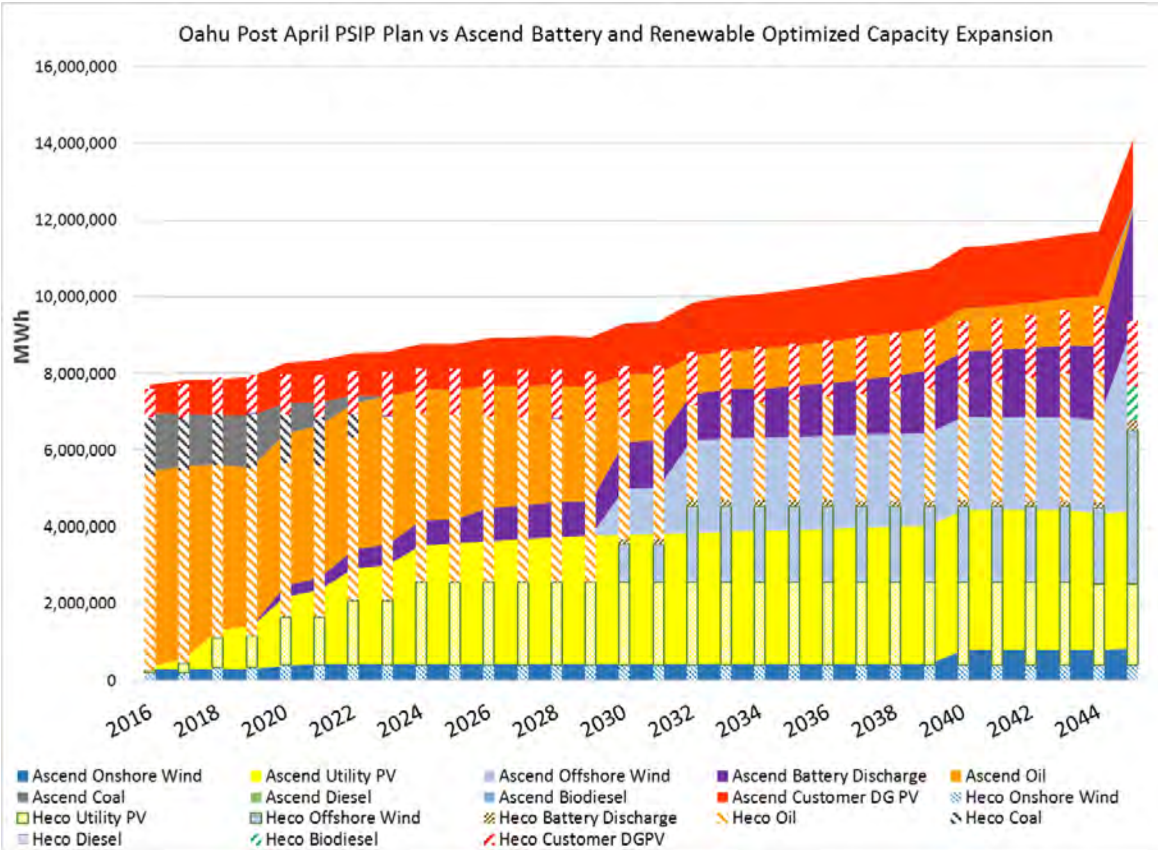
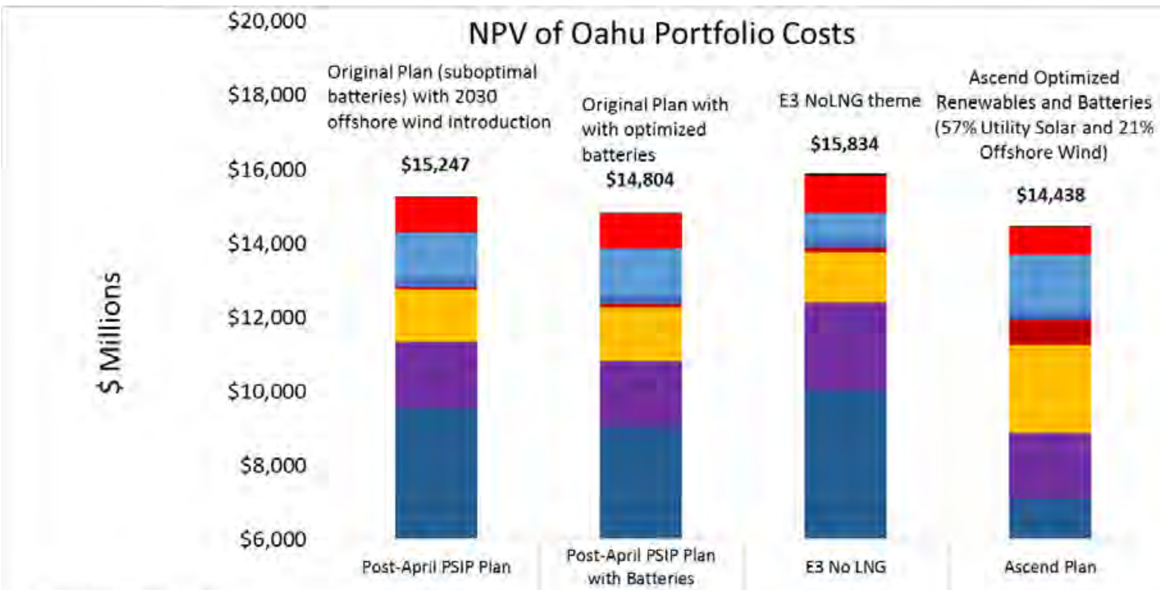


Figure 30: Comparison of the Oahu Post-April PSIP Plan and the Oahu Ascend Plan by resource.

Figure 30 provides a comparison over time of the distinct types of resource generation contained in the Post-April PSIP Plan and the Ascend Plan. The generation from the installed resource capacities for the Post-April PSIP Plan are represented by the bars, while the generation from the installed resource capacities for the Ascend Plan are represented by the shaded areas behind the bars. The two plans start off with identical levels of resource generation. However, by 2020 the overall generation of the Ascend Plan begins to exceed the total generation of the Post-April PSIP Plan, due largely to the accelerated growth of solar generation and the introduction of batteries. With the accelerated growth of solar generation and batteries, the amount oil-based generation by 2032 is two and half times smaller for the Ascend Plan than the Post-April PSIP Plan. By 2040, with additional installations of wind for the Ascend Plan, the amount oil-based generation for the Ascend Plan is nearly three times less than the oil-based generation in the Post-April PSIP Plan.



	Post-April PSIP Plan	Post-April PSIP Plan with Batteries	E3 No LNG	Ascend Plan
Unserved Energy Costs	$1	$1	$50	$1
Risk Premium	$956	$944	$1,016	$759
Capital Costs (Offshore Wind)	$1,251	$1,251	$686	$1,513
Capital Costs (Onshore Wind)	$226	$226	$240	$226
Capital Costs (Batteries)	$46	$113	$131	$703
Capital Costs (Utility PV)	$1,436	$1,436	$1,367	$2,354
New DGPV and DER Integration Costs	$1,787	$1,787	$2,380	$1,787
Capital + Fixed Costs (LNG)	$0	$0	$0	$0
Production Costs	$9,545	$9,048	$10,015	$7,095

Figure 31: NPV of Portfolio Costs for Oahu's four plans.

As Figure 31 shows, adding an optimized battery buildout plan to the Post-April PSIP Plan results in a $443 M reduction in Oahu's NPV of portfolio costs from the original Post-April PSIP Plan. Ascend's optimization of both batteries and renewables, yielding the Ascend Plan, occasions a $809 M reduction in portfolio costs. On the other hand, the E3 Plan increases NPV portfolio costs by $587 M. The increase in costs relative to the original Post-April PSIP Plan results from the lack of development of flexible thermal generation, which causes the E3 Plan to have the highest production costs out of the four plans examined, and incur a $50 M penalty for its nonfulfillment of resource adequacy standards.

4.5. Maui Results and Optimized Plans

In this subsection, Ascend evaluates the Maui Post-April PSIP Plan with Batteries, and then the Maui Ascend Plan. At the end of this subsection, Ascend compares the two Ascend-developed plans with the original Post-April PSIP Plan and the E3 plan.

4.5.1. The Optimization of Batteries: Post-April PSIP Plan with Batteries

The Maui Post-April PSIP Plan with Batteries was created through PowerSimm's optimization of batteries for the original Post-April PSIP Plan. The optimal battery buildout plan is depicted in Figure 32 below.

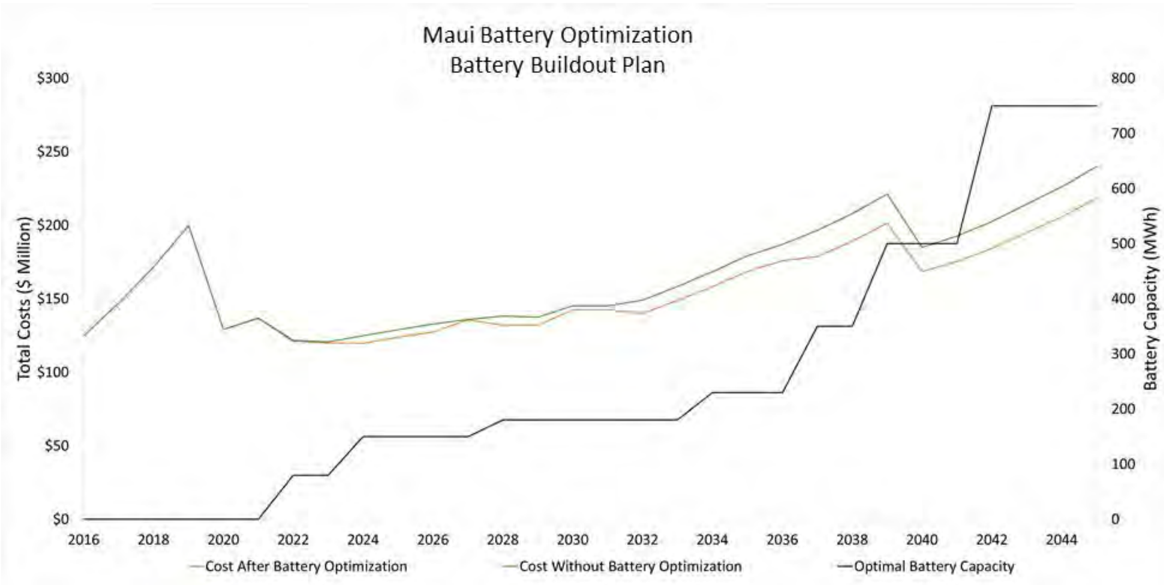


Figure 32: Battery buildout plan for the Maui Post-April PSIP Plan with Batteries.

The black line denotes battery capacity over the years; the green line represents the costs without batteries; and the orange line represents the costs with batteries. It is interesting to note that the production costs drop considerably by 2020. The installation of solar and onshore wind in the Maui Post-April PSIP Plan causes this drop in costs. After the installation of solar and wind, batteries begin to be built out by 2021. Load-shifting batteries begin to provide a notable level of savings by 2032.

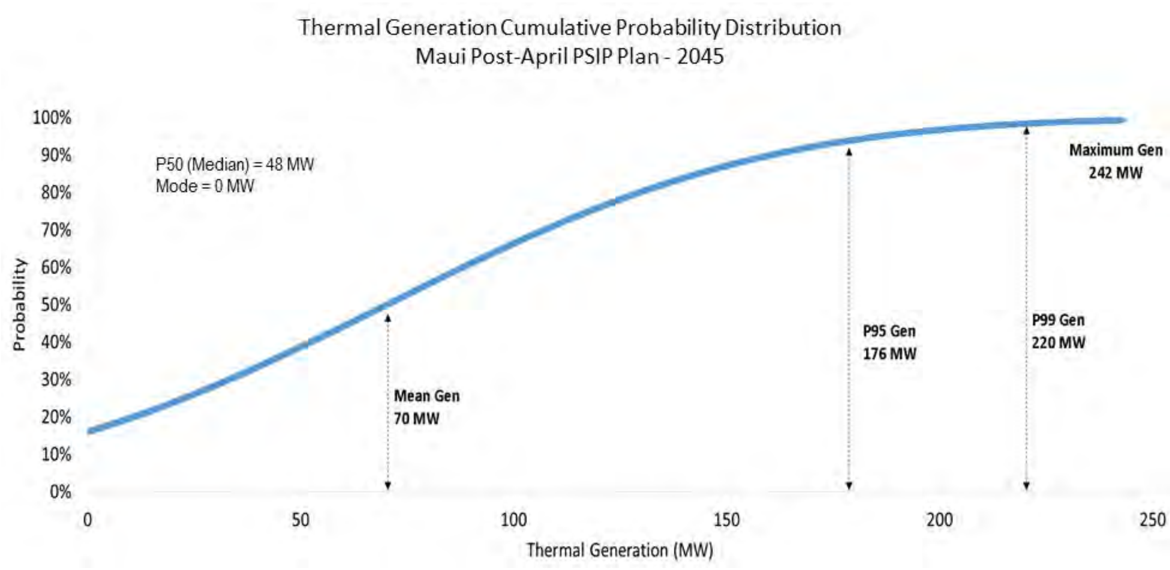


Figure 33: Cumulative probability distribution of thermal generation over distinct weather simulations for the Maui Post-April PSIP Plan (without batteries) in 2045.

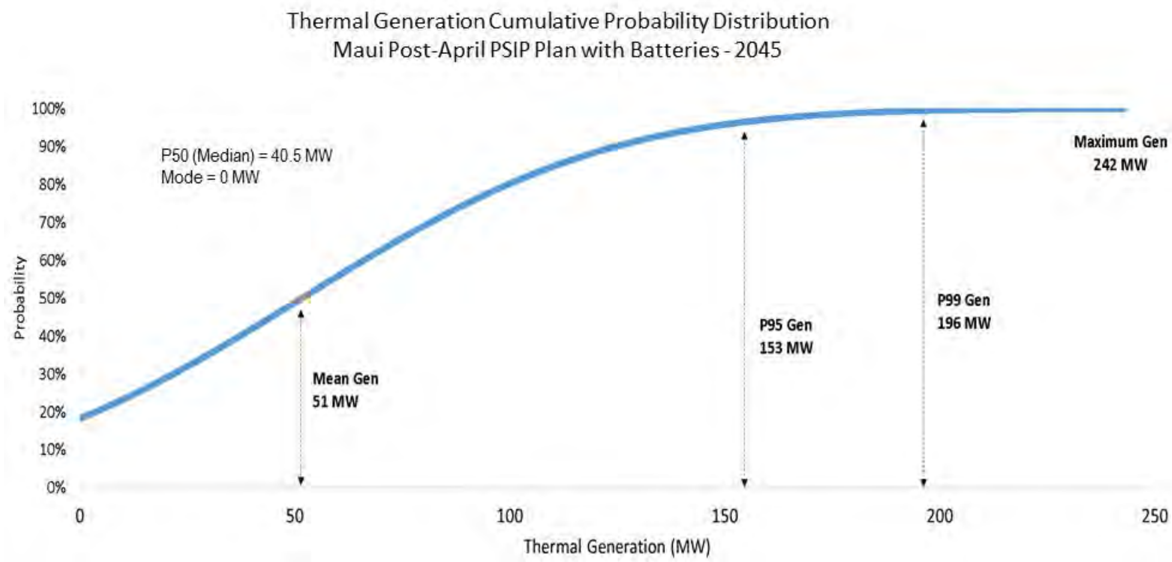


Figure 34: Cumulative probability distribution of thermal generation over distinct weather simulations for the Maui Post-April PSIP Plan with optimized batteries in 2045.

Figure 33 and Figure 34 provide a comparison of the probability distribution of thermal generation in 2045 without batteries and with optimized batteries. Since Maui's energy system is renewable dominant, the mode, or the amount of thermal generation most often required, is 0 MW, with or without batteries. Nevertheless, there are ample instances when thermal generation will be required, as indicated by the average amount of thermal generation for 2045 reaching 70 MW under the Maui Post-April PSIP Plan and 51 MW under the Maui Post-April PSIP Plan with Batteries. Though the average amount of thermal generation decreases by 27% with the addition of optimized batteries, the P95th confidence interval (i.e. the value of which there is 95% chance that the amount of thermal generation required will be less than this value) only decreases by 13% with optimized batteries, and the maximum amount of thermal generation remains at 242 MW, or 124% of average load for the year, for both of the plans. Thus battery additions lessen the need for thermal generation, but the same amount of thermal generation capacity will be needed under both plans to ensure security of supply under the most extreme weather scenarios.

4.5.2. The Optimization of Renewables and Batteries: The Ascend Plan

Ascend jointly optimized solar, wind and batteries to determine the resource plan that would provide the lowest portfolio costs for Maui. Due to the small size of the island, Ascend constrained the optimization of renewables to 100% of its present generation capacity. The results from this co-optimization process of renewables and batteries is presented in Figure 35 below.

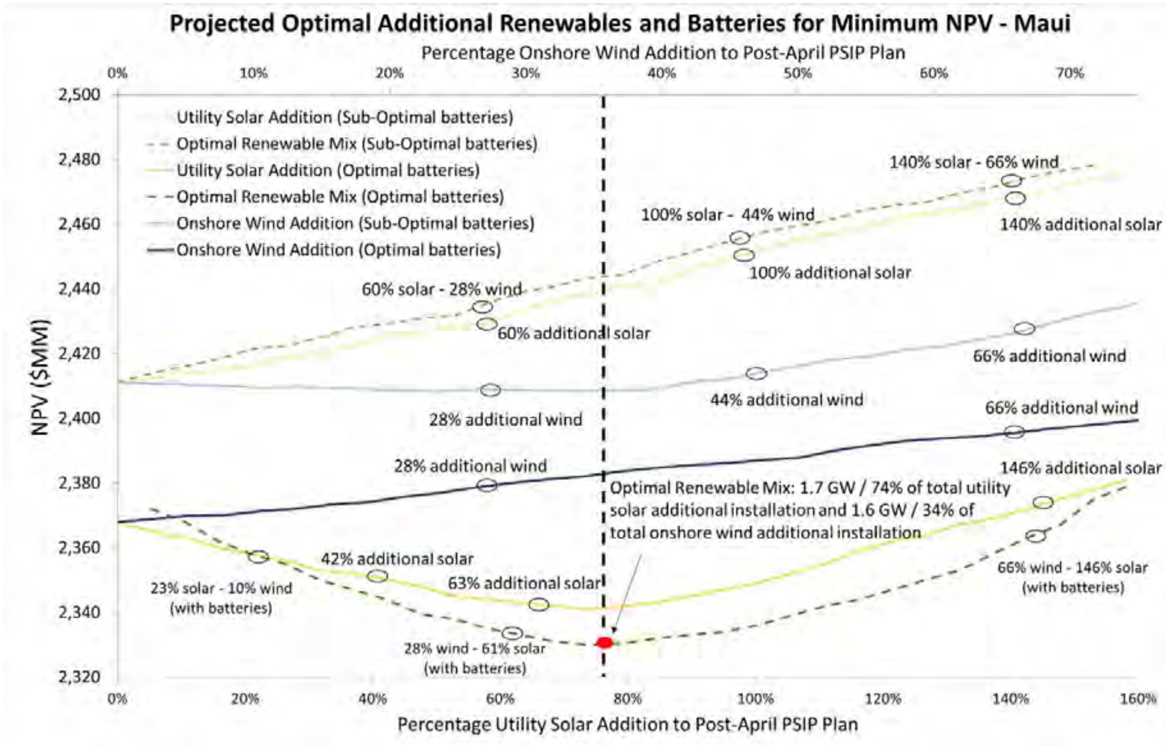


Figure 35: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries for Maui.

Figure 35 illustrates that the mix of renewables and batteries that provided the lowest NPV costs corresponds to, relative to the original Maui Post-April PSIP Plan, a total additional installation of 74% of utility solar and a total additional installation of 34% of onshore wind. Furthermore, Figure 35 conveys that without optimal levels of batteries additional renewables, instead of providing a reduction in costs, generate an increase in production costs.

Figure 36 shows the battery buildout plan under the Maui Ascend Plan, further highlighting the production cost savings that optimal batteries provide.

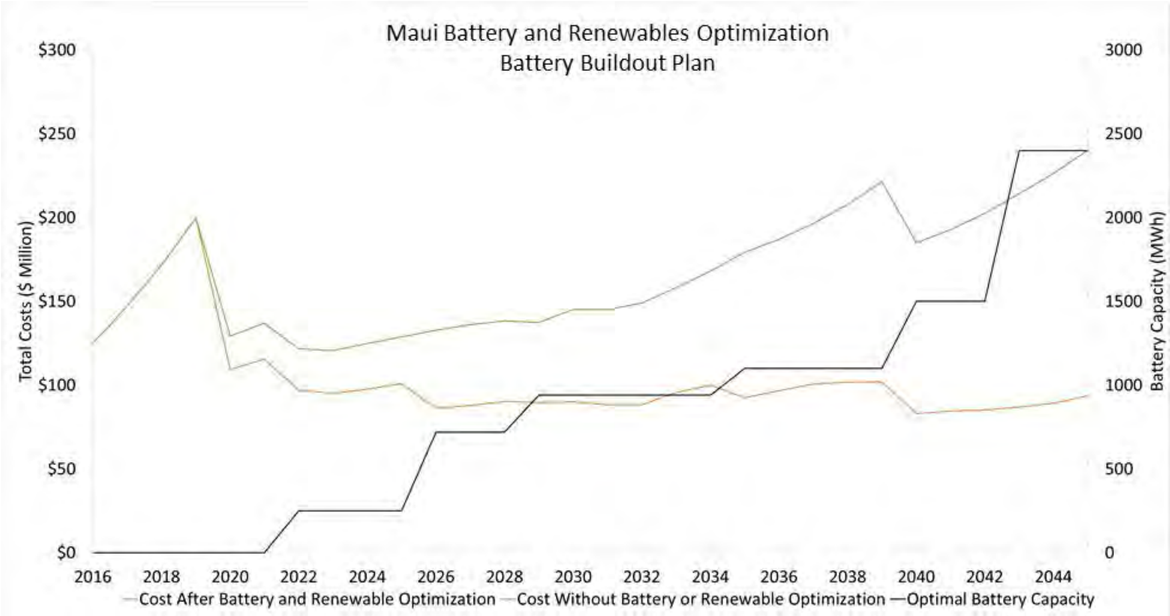


Figure 36: Battery buildout plan for the Maui Ascend Plan.

The battery capacity for the Maui Ascend Plan exceeds the 2045 battery capacity of the Post-April PSIP Plan with batteries by 2026, and by 2045 the former plan's battery capacity is approximately three times higher than the latter. The production cost savings decrease significantly, as the increased renewable capacity makes greater use of the economic potential of batteries.

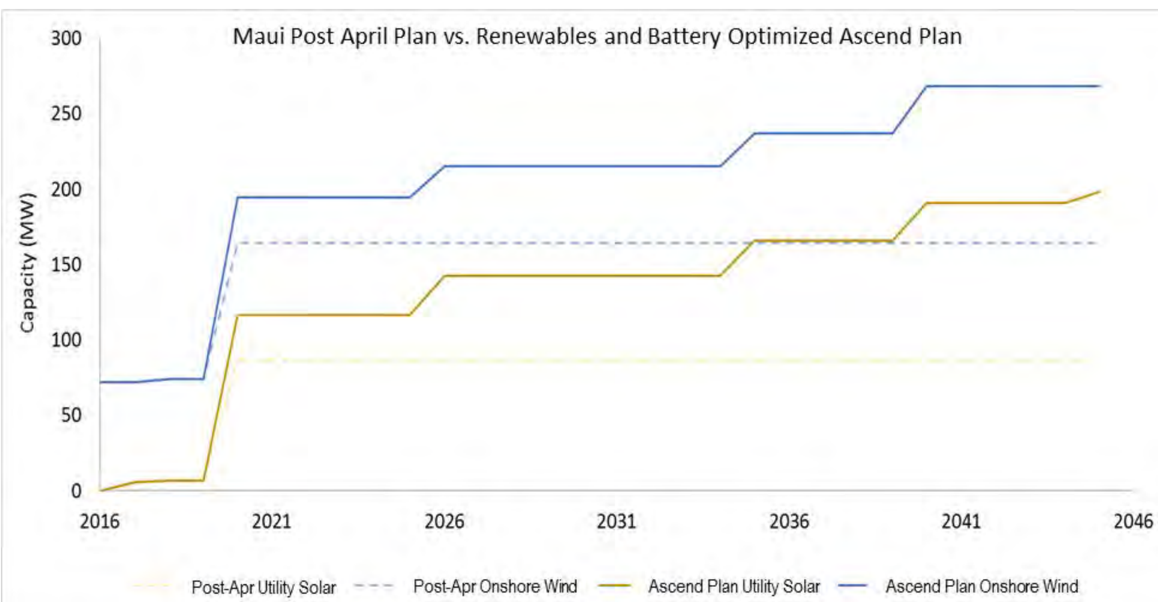
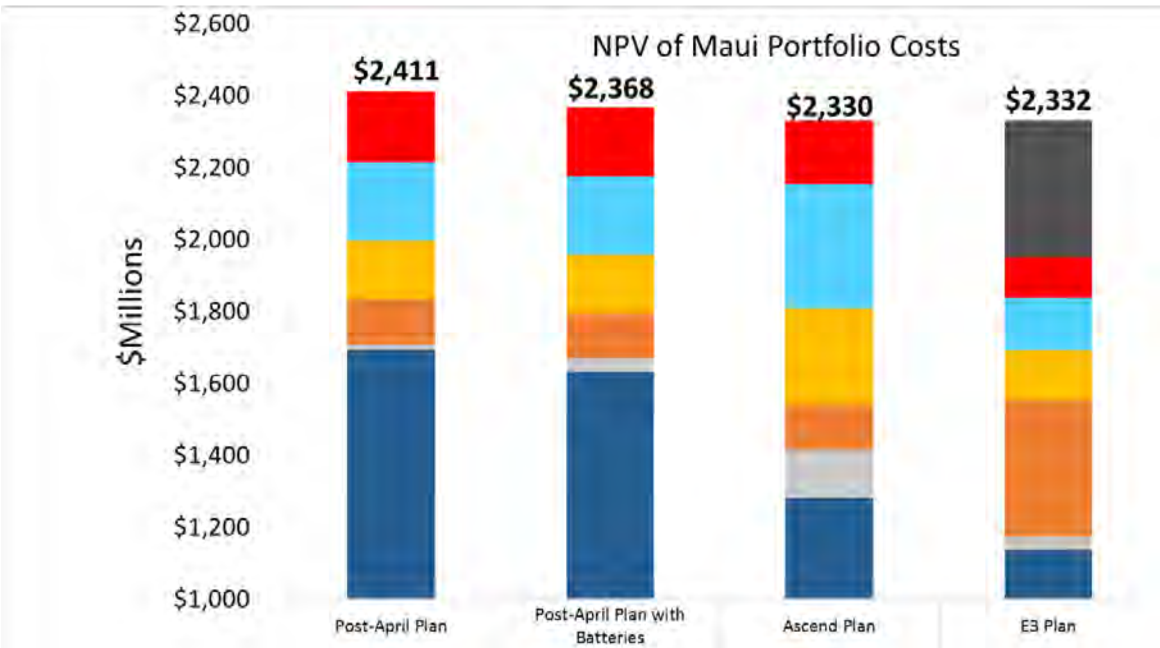


Figure 37: Comparision of renewable capacity additions between the Maui Post-April PSIP Plan and Ascend Plan.

Figure 36 illustrates the capacity additions to the Maui Post-April PSIP Plan that generates the optimal Maui Ascend Plan. The base assumption of the Post-April PSIP Plan consists of one-time additions in 2020 of 80 MW of solar and 90 MW of onshore wind. Ascend's optimized plan introduces an additional 30 MW of solar and wind in 2020, and continues to gradually increase renewable capacities over time. The Maui Ascend Plan does not, as in the case of the Oahu Ascend Plan, increase renewables at the same rate each year. For Maui, seventy-four percent additional solar and 34% additional onshore wind capacities over the entire study timeframe, i.e. from 2017 to 2045, provide the least cost plan, when combined with optimal levels of batteries.



	Post-April Plan	Post-April Plan with Batteries	Ascend Plan	E3 Plan
Unserved Energy Cost	$0	$0	$0	$382
Risk Premium	$198	$194	$175	$113
Capital Costs (Onshore Wind)	$217	$217	$347	$146
Capital Costs (Utility Solar)	$162	$162	$267	$139
New DGPV	$126	$126	$126	$378
Capital Costs (Battery Storage)	$15	$37	$132	$37
Production Costs	$1,693	$1,632	$1,282	$1,138

Figure 38: Comparison of NPV of Maui Portfolio costs for the Post-April PSIP Plan, the Post-April PSIP Plan with Batteries, the Ascend Plan, and the E3 Plan.

When the Post-April PSIP Plan is optimized with batteries, Maui portfolio costs decrease by $43 M, while when PowerSimm optimizes the Plan with batteries and renewables, portfolio costs decline by $81 M. The E3 Plan provides dramatically lower NPV costs when penalties for unserved energy are not included. However, due to the E3 Plan's failure to meet resource adequacy standards, as presented in section 4.3.2., PowerSimm adds an additional $382 M in portfolio costs to the plan, bringing the NPV portfolio costs to $2,332 M, or $79 M less than the Post-April PSIP Plan.

4.6. Hawaii Results and Optimized Plans

In this section, Ascend analyzes the Hawaii Post-April PSIP Plan and its optimized counterparts. Due to favorable wind conditions on the Big Island, virtually all of its renewable generation installations are of onshore wind. Thus Hawaii provides an interesting study of the potential savings provided when batteries are coupled with on-shore wind generation. In this subsection Ascend analyzes the Hawaii Post-April PSIP Plan optimized with load-shifting batteries (the Post-April PSIP Plan with Batteries), and then the Hawaii Post-April PSIP Plan optimized with batteries and renewables (the Ascend Plan).

4.6.1. The Optimization of Batteries: Post-April PSIP Plan with Batteries

Hawaii's Ascend-optimized battery buildout plan is shown in Figure 39 below. By 2045, the battery capacity is 135 MWh, which is significantly more than the 15 MWh of batteries that the original Hawaii Post-April PSIP Plan proposes. The reduction in costs provided by batteries, however, is minimal. Wind generation and DGPV at the Post-April PSIP Plan's levels do not reap substantial savings from battery utilization.

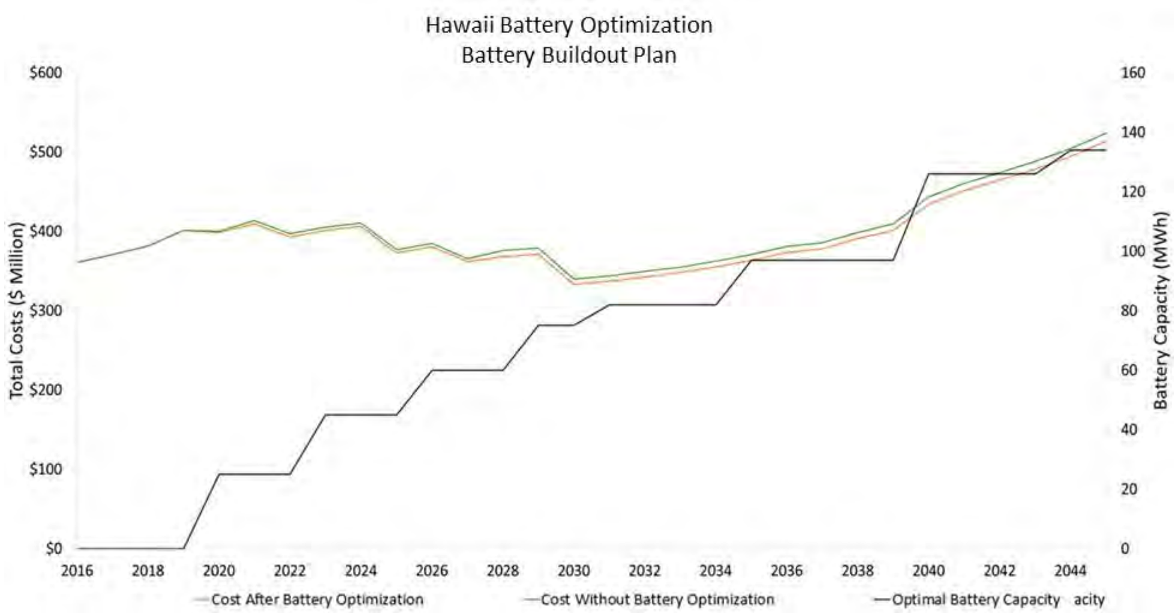


Figure 39: Battery buildout plan for HELCO's Post-April PSIP Plan with Batteries.

Figure 40 and Figure 41 provide a comparison of the cumulative probability distribution of thermal generation requirements for Hawaii in 2045 with and without optimized batteries. For the Post-April PSIP Plan with Batteries, the average thermal generation for 2045 decreases by 37% and the P95th by 15%. However, as in the case of Maui, the maximum thermal generation required to ensure security of supply for the most extreme weather scenarios stays the same between the plans with and without batteries.

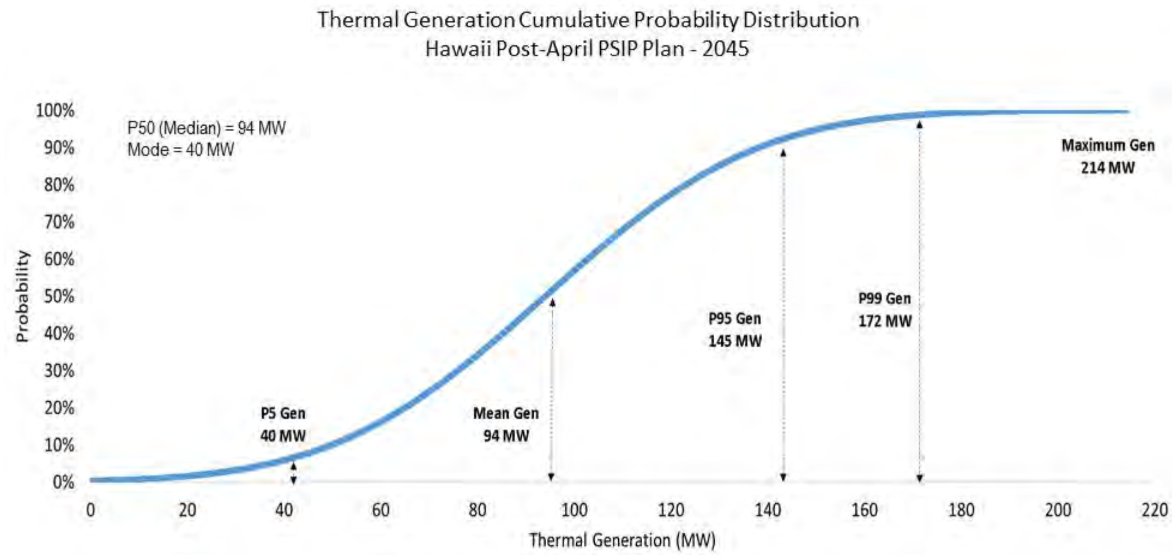


Figure 40: Cumulative probability distribution of thermal generation over distinct weather simulations for HELCO's Post-April PSIP Plan (without batteries) in 2045.

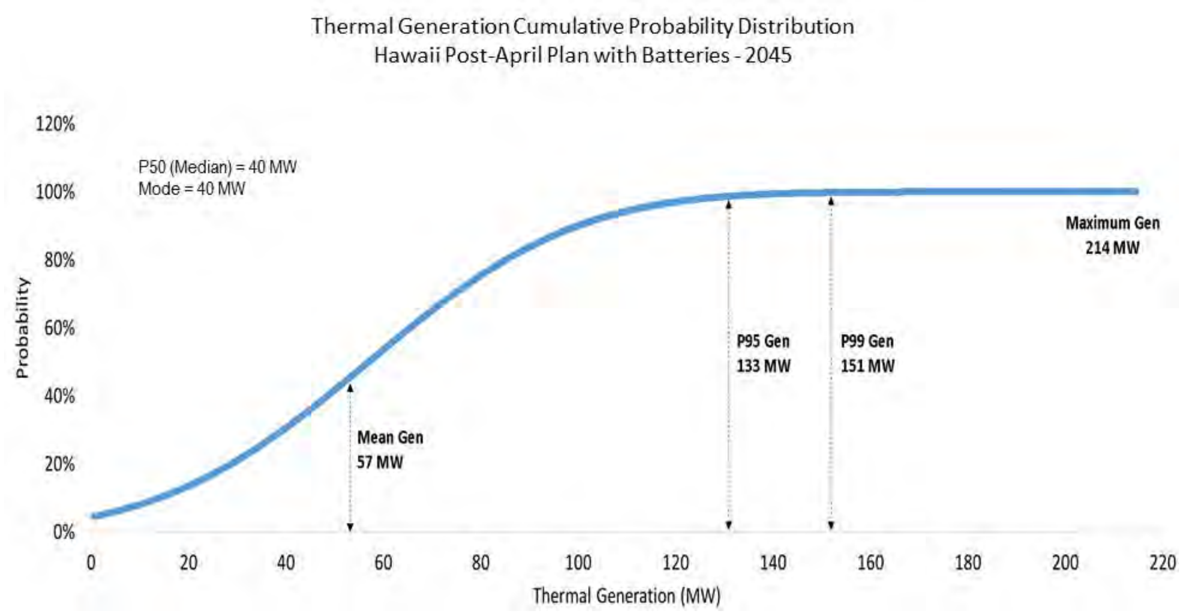


Figure 41: Cumulative probability distribution of thermal generation over distinct weather simulations for HELCO's Post-April PSIP Plan with Batteries in 2045.

4.6.2. The Optimization of Renewables and Batteries: The Ascend Plan

Unlike for the other islands, Ascend's joint optimization of renewables and batteries contains no utility solar additions for Hawaii. The capacity factors on the Big Island are much higher for wind than solar, rendering additional wind without solar the optimal path forward for lowering Hawaii's NPV portfolio costs.

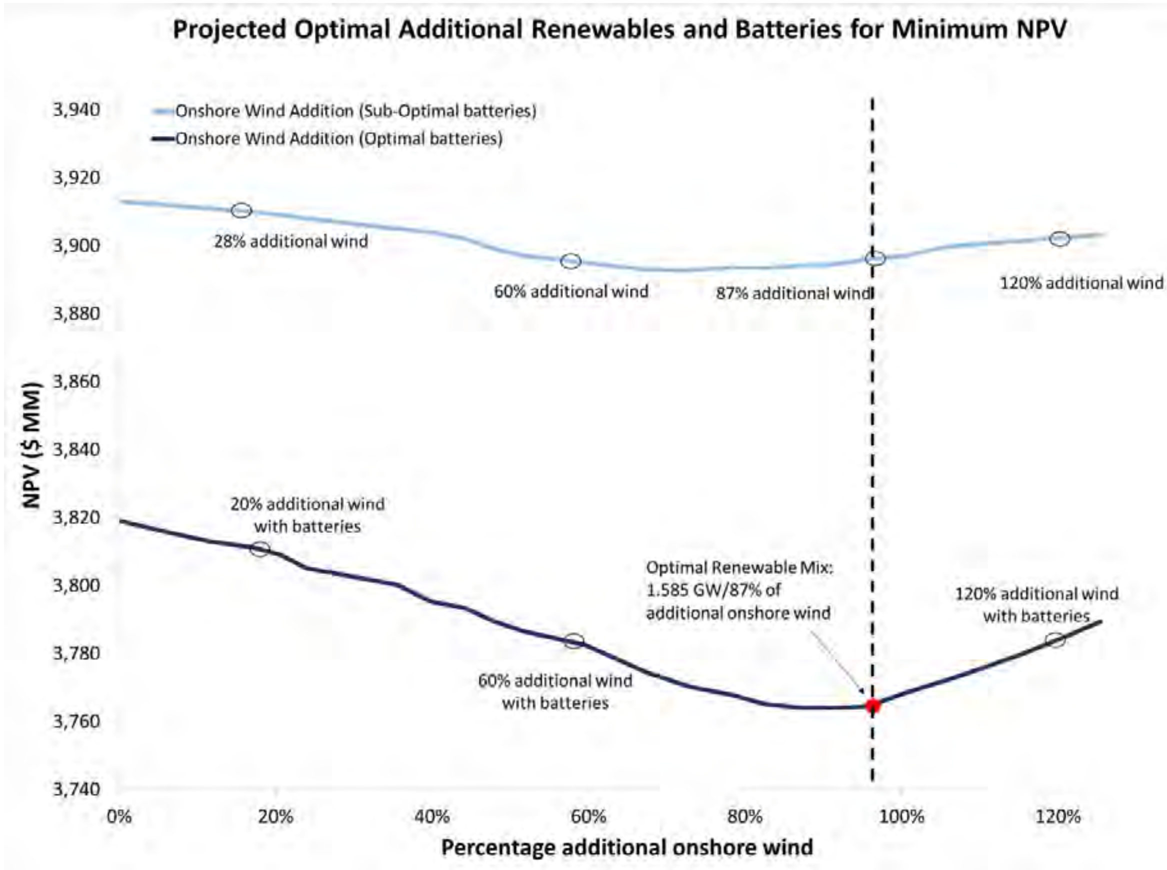


Figure 42: Results of Ascend's co-optimization of offshore wind, utility solar, and batteries for Maui.

Figure 42 presents that the optimal renewable mix for Hawaii contains 87% MW of additional onshore wind relative to the Hawaii Post-April PSIP Plan, combined with batteries. Figure 42 further presents that there is indeed a portfolio effect between batteries and the additional wind generation, confirming that batteries are essential for minimizing the NPV costs of Hawaii's wind optimization plan.

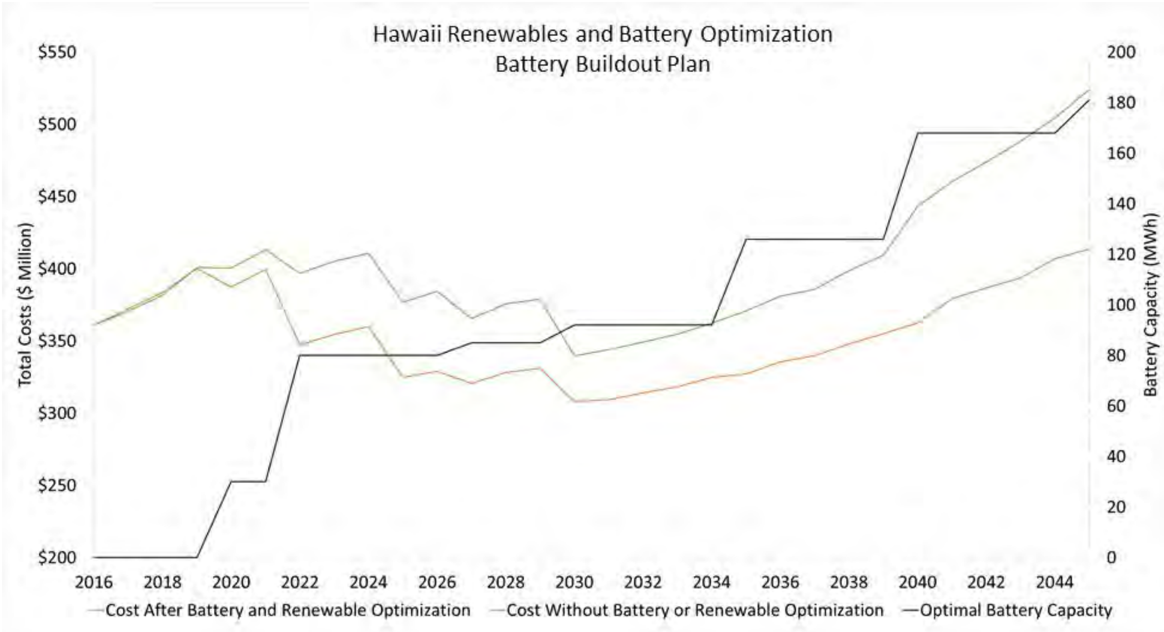


Figure 43: Battery buildout plan for HELCO's Ascend Plan.

Figure 43 presents the optimal levels of batteries for the Hawaii Ascend Plan, further driving home the economic benefits of the wind combined with batteries for Hawaii. The Hawaii Ascend Plan builds out battery capacity to 180 MWh, which is 35 MWh more battery capacity than in the Hawaii Post-April PSIP Plan with Batteries. Due to the absence of solar, the percent increase in battery installations from the Post-April PSIP Plan with Batteries to the Ascend Plan is lower for Hawaii relative to the two other islands. Nevertheless, with the additional battery capacity and wind generation, production costs begin to drop as early as 2022, revealing a pronounced portfolio effect between batteries and wind generation.

Figure 44 compares the difference in renewable capacities between the original Hawaii Post-April PSIP Plan and Ascend's optimization of the plan (the Hawaii Ascend Plan). The Hawaii Post-April PSIP Plan has two 20-MW increases in onshore wind capacity, the first in 2020 and the second in 2030. Unlike the Oahu Ascend Plan, the Hawaii Ascend Plan does not increase the amount of renewable capacity at the same, fixed rate each year. The Hawaii Ascend Plan provides and 87% increase in onshore wind capacity over the entire study timeframe. Compared to the Post-April PSIP Plan, the Ascend Plan has installed an additional 125 MW of onshore wind capacity by 2045.

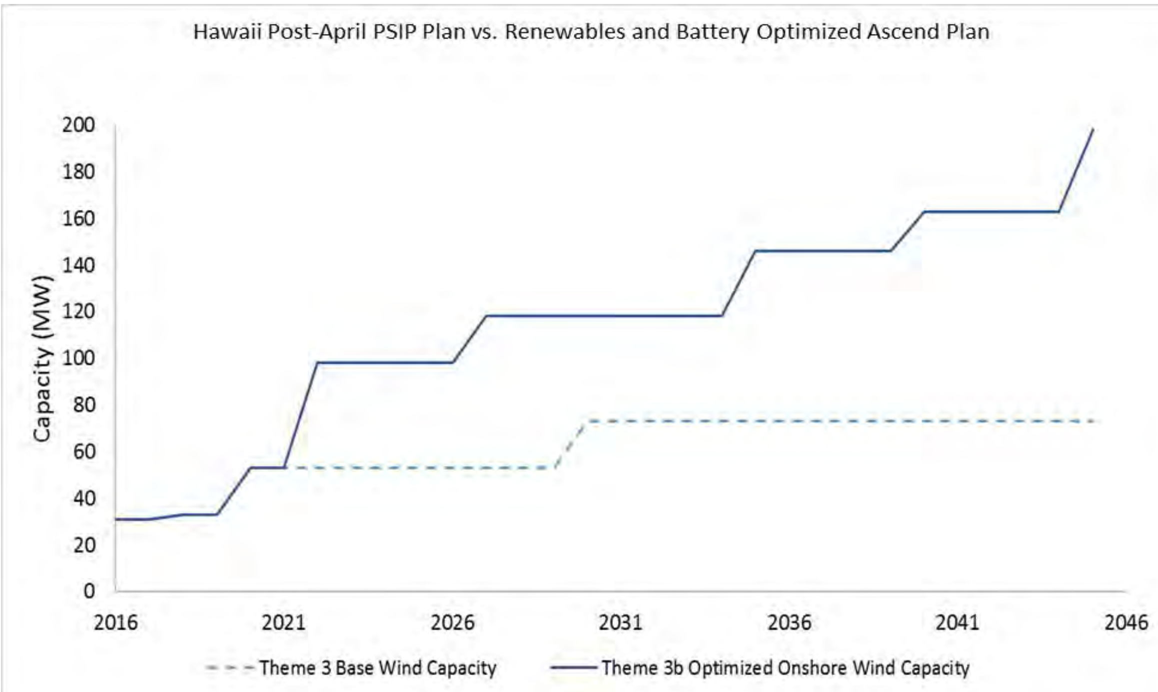
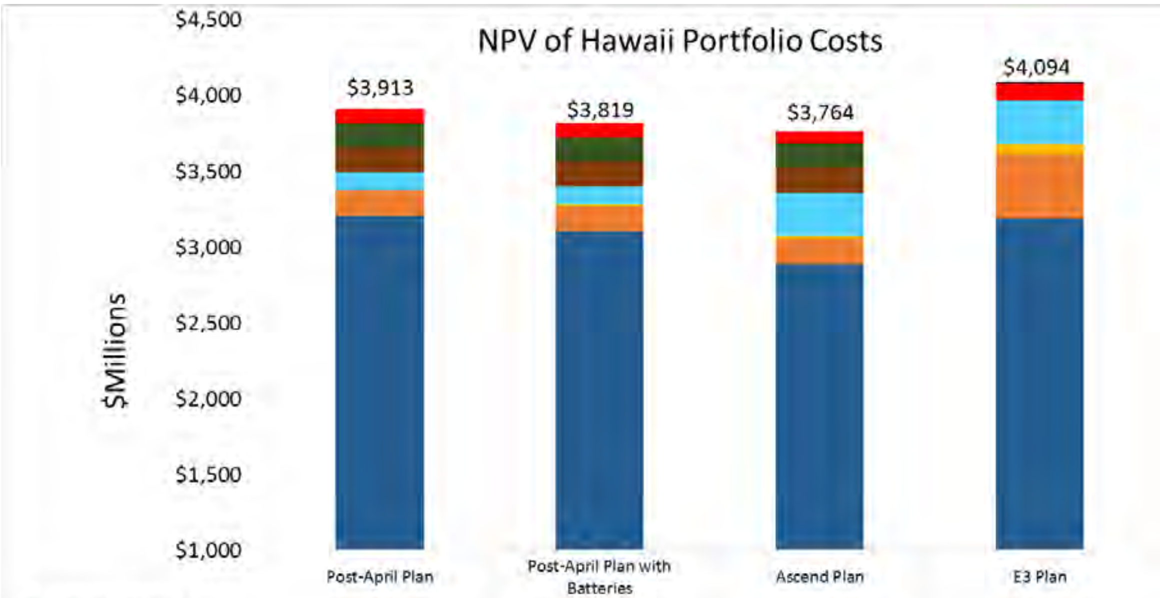


Figure 44: Comparison of renewable capacity additions between HELCO's Post-April PSIP Plan and Ascend Plan.



	Post-April Plan	Post-April Plan with Batteries	Ascend Plan	E3 Plan
Unserved Energy Cost	$0	$0	$0	$16
Risk Premium	$96	$96	$81	$113
Operating Cost (Hydro)	$0	$0	$0	$0
Capital Costs (Biomass)	$158	$158	$158	$0
Capital Costs (Geothermal)	$166	$166	$166	$0
Capital Costs (Onshore Wind)	$116	$116	$285	$288
Capital Costs (Battery Storage)	$0	$14	$19	$63
New DGPV	$169	$169	$169	$425
Production Costs	$3,208	$3,101	$2,886	$3,190

Figure 45: NPV of HELCO portfolio costs for the four HELCO Plans.

When the Post-April PSIP Plan is optimized with batteries, Hawaii portfolio costs decrease by $94 M; when the original is optimized with batteries and renewables, yielding the Ascend Plan, Hawaii portfolio costs fall by 4%, or $149 M. The E3 Plan, however, increases portfolio costs by $181 M.

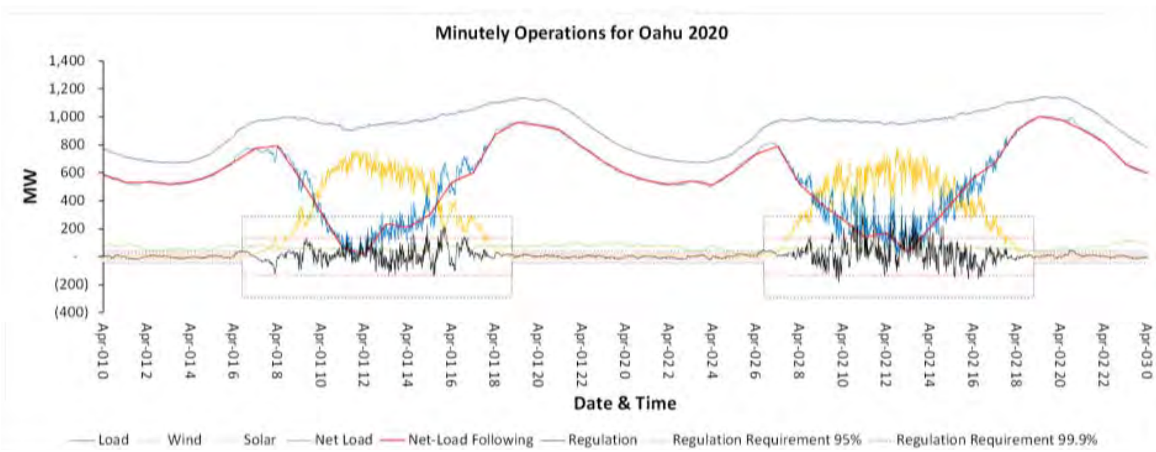
5. Flexibility Analysis

While most planning models assume perfect foresight in dispatch decision-making, such perfect decisions are impossible to make in the real world. On a minutely level, not only is load unpredictable, but with an energy portfolio containing a high level of renewables, generation can be unpredictable as well. Due to the unpredictable nature of both load and generation, batteries are an excellent option for flexible generation because of their very fast and precise charge/discharge capabilities in comparison to thermal generation units with its significant ramp-up times and high costs.

Ascend utilized the PowerSimm module, System Flexibility Software, to help the Companies determine future regulation requirements and the most cost effective ways of meeting those requirements. This section will first discuss Ascend's System Flexibility Software, which calculates the Companies' flexible generation requirements, such as regulation requirements, 15-minute ramps and 1-hour ramps. Then the section will consider PowerSimm's determinations of the most cost-effective way to meet these flexible generation requirements.

5.1. System Flexibility Software

The objective of Ascend's System Flexibility Software is to determine the amount of flexible generation capacity required when planning to integrate intermittent renewable energy sources into an energy system. Flexibility requirements are estimated in terms of (1) regulation requirements necessary to maintain CPS2 scores at 95 and 99.9, (2) ramping requirements at both 15-minute and 1-hour time steps, and 3) changes in ramping direction of net load. Due to the large proportion of solar generation, these requirements are estimated by day-time and night-time requirements. The software determines flexible generation requirements by estimating the variability of historical minutely data for load and renewable generation.



Year	2020	
Day-Time Regulation Requirement 95%	167	MW
Day-Time Regulation Requirement 99.9%	372	MW
Day-Time 15 minute Physical Ramp Up	445	MW
Day-Time 15 Minute Physical Ramp Down	352	MW
Day-Time 1 hour Physical Ramp Up	688	MW
Day-Time 1 hour Physical Ramp Down	475	MW
Night-Time Regulation Requirement 95%	36	MW
Night-Time Regulation Requirement 99.9%	105	MW
Night-Time 15 Minute Physical Ramp Up	187	MW
Night-Time 15 Minute Physical Ramp Down	37	MW
Night-Time 1 Hour Physical Ramp Up	359	MW
Night-Time 1 Hour Physical Ramp Down	203	MW

Figure 46: Oahu forecasted load, renewable generation and regulation for April 15th and 16th, 2020, with accompanying chart.

Figure 46 shows the central results provided by System Flexibility Analysis. The upper dark blue line indicates the load, which has relatively little variation, following the pattern of a muted sine wave. The light blue line denotes net load. Net load is calculated by subtracting solar (indicated by the yellow line), wind (indicated by the green line) and must-run thermal generation (not visually indicated in graphic) from system load. One of the aspects of intermittent renewables, especially solar, is significant, rapid fluctuations in generation, which causes parallel fluctuations in net-load, disrupting the originally quiescent sine wave pattern of system load. Thus, volatility in renewable generation by extension renders net load volatile. Regulation (indicated by the black line) is tasked with balancing out these fluctuations at a minutely level. These fluctuations are the difference between net-load following and minutely generation. Net load following, indicated by the red line, is measured as the linear hourly ramps based on the hourly average of net load. The regulation requirement necessary to maintain CPS2 scores at 95 and 99.9 are signified by the red dotted line and blue dotted line respectively. CPS2 scores are a monthly cumulative measure of the area control error (ACE) that measure the divergence between energy supply and load. A large ACE would result in an increase or decrease in system frequency.

The intermittency of renewable generation largely determines the extent of regulation required. The regulation associated with load for 2020 is 167 MW, or approximately 18% of load. However, the higher renewable generation capacity in 2030 increases the amount of regulation to 313 MW, or 34% of load. As mentioned in the previous paragraph, regulation balances out the uneven generation in renewables. The off-peak (night-time) hours in Figure 46 reflects the joint variability in load and wind generation, which yield 18 MW of regulation requirements in 2020. On the other hand, the on-peak hours, when solar generation is active, result in a regulation requirement of 167 MW.

Change in Solar Generation (MW)	Regulation Requirement (MW)	Percentage Increase of Regulation Requirement	Max 1-Hour Ramp (MW)	Percentage Increase of Max 1-Hour Ramp
0	167	--	688	--
+20	170	1.7%	691	0.4%
+40	174	4.2%	695	1.0 %
+100	184	10.2%	706	2.6%
+200	202	21.0%	720	5.2%
+300	222	32.9%	741	7.7%

Table 5: Oahu, 2020 – flexible generation requirements with additions of solar capacity.

Change in Onshore Wind Generation (MW)	Regulation Requirement (MW)	Percentage Increase of Regulation Requirement	Max 1-Hour Ramp (MW)	Percentage Increase of Max 1-Hour Ramp
0	167	--	688	--
+20	168	0.6%	687	-0.1%
+40	169	1.1%	686	-0.3 %
+100	171	2.3%	685	-0.4%
+200	176	5.3%	685	-0.4%
+300	181	8.4%	686	-0.3%

Table 6: Oahu, 2020 – flexible generation requirements with additions of onshore wind capacity.

A comparison of Table 5 and Table 6 illustrate the effect of increasing solar and onshore wind capacity on flexible generation requirements. As these results suggest, solar tends to have a more considerable effect on flexible generation requirements than wind. Solar has capacity factors of about 20% with the preponderance of generation in the six hours from 9 am to 3 PM. This concentration of solar generation leads to high ramps and the potential for curtailed energy. Moreover, the high spatial concentration of solar contributes to an even higher increase in regulation requirements per MW of added solar, relative to what is seen on the mainland. Complementing solar with wind mitigates the concentration effect with wind generating relatively uniformly over the day. As Table 6 shows, additional onshore wind capacity has a very limited effect on maximum 1-hour ramps, and even marginally lowers these ramps caused by solar, due to its steadier rates of generation relative to solar. Wind has capacity factors in the state of Hawai'i ranging from 40 to 70%.

Moreover, additional intermittent renewables increase the frequency of changes in the gradient for load following. Figure 47 shows how intermittent renewable generation can cause a sawtooth pattern in the red, net-load following line. In the morning hours of April 1st, 2032, the gradient of the net-load following changes 7 times.

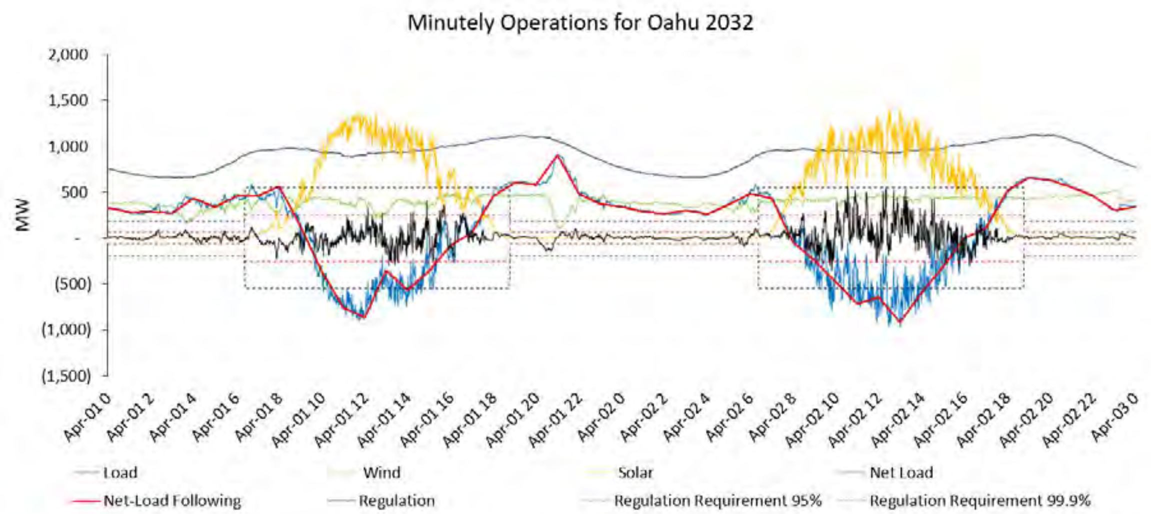


Figure 47: Oahu forecasted load, renewable generation and regulation for April 1st and 2nd, 2032.

5.1.1. Oahu Results

The Daytime Regulation in Table 5 below is the regulation requirement necessary for maintaining a CPS2 score of 95. The Contingent Reserve is the power the energy system should be able to provide in the event of unusual load requirements. It is determined as 6% of peak load for the year. The Max 15-Minute Ramp and 1-Hour Ramp are the largest absolute values from Ramp Up and Ramp Down for their respective time steps, as found in the System Flexibility Software chart. On-Peak Total Flexible Generation is the total power capacity of the ancillary services in peaking conditions for that year. It is determined by summing Day-Time Regulation, Contingent Reserve and the Max 1-Hour Ramp for each year.

Year	Day-Time Regulation (95%) (A)	Contingent Reserve (B)	Max 15- Minute Ramp	Max 1-Hour Ramp (C)	On-Peak Total Flexible Generation (A+B+C)
2017	103	74	400	584	761
2018	127	76	420	633	836
2019	134	78	427	650	862
2020	167	78	445	688	933
2021	188	79	456	706	973
2025	262	81	474	738	1081
2030	313	83	502	798	1194
2035	367	91	543	854	1312
2040	400	96	584	924	1420
2045	479	103	642	1,013	1595

Table 7: Oahu renewable integration requirements for flexible generation. All results are unitized in MW.

As Table 5 indicates, Oahu's flexible generation requirements grow considerably with the higher penetration of intermittent renewables over the years. The regulation requirements that Oahu will have to meet more than double in size from 2017 to 2025. Batteries and an updated flexible thermal fleet become crucial and cost-effective assets in meeting these requirements.

Figure 48 provides a visual, side-by-side comparison of renewable generation and flexible generation requirements for the same historic window (April 4th) in 2017 and 2025. The increase in solar generation appears to be the main driver of the increasing flexible generation requirements. In this time period, solar generation capacity (inclusive of DGPV) increases by 152%, from 629 MW to 1,587 MW. Flexible generation requirements in turn increase by 42%, from 761 MW to 1,081 MW.

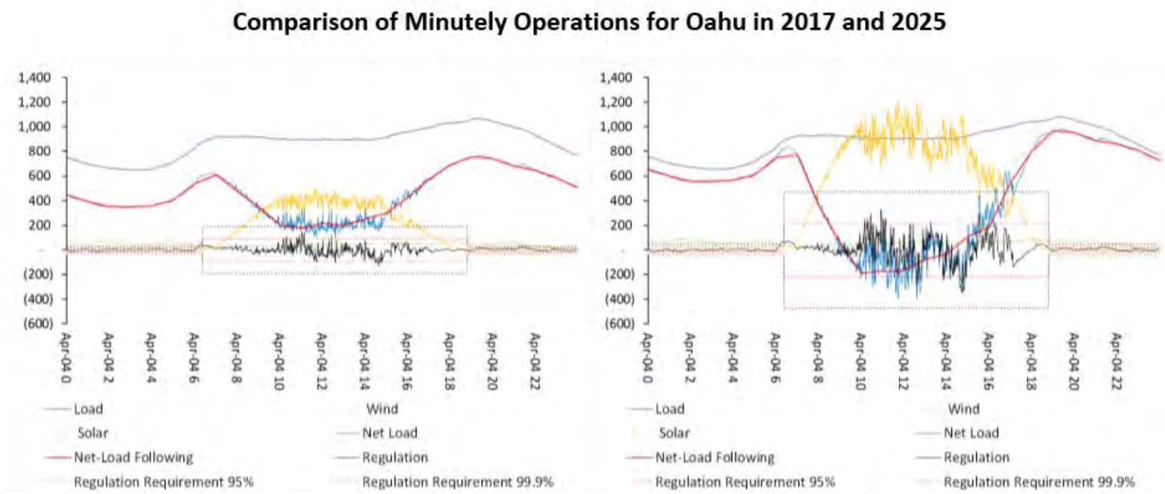


Figure 48: Side-by-Side comparison of renewable generation, load and regulation requirements on April 4th, 2017 and 2025. April 4th, 2017 is depicted on the left and April 4th, 2025 is depicted on the right.

5.1.2. Maui Results

The Maui Post-April PSIP Plan contains an installation of 80 MW of utility solar, and 90 MW of onshore wind in 2020, while in the other years there is no significant installation of renewables. Thus, flexible generation requirements for Maui grow at relatively conservative levels, with the exception of 2020, during which the flexible generation requirements increase by 61%.

Year	Day-Time Regulation (95%)	Day-Time Regulation (99.9%) (A)	Contingent Reserve (B)	Max 15-Minute Ramp	Max 1-Hour Ramp (C)	On-Peak Total Flexible Generation (A+B+C)
2017	38	76	12	88	111	199
2018	39	77	12	88	112	201
2019	39	79	13	90	113	205
2020	64	129	13	147	188	330
2021	64	129	13	147	188	330
2025	65	130	14	149	189	333
2030	66	132	13	150	191	336
2035	66	133	14	83	192	339
2040	71	142	15	165	215	372
2045	76	153	16	177	238	407

Table 8: Maui - Renewable integration requirements for flexible generation. Unlike for Oahu, On-Peak Total Flexible Generation is calculated using Day-Time Regulation Requirement necessary to maintain a CPS2 score of 99.9, as opposed to 95.

Figure 49 shows the effect of the additional renewable capacity in 2020 by providing a side-by-side comparison of forecasted renewable generation for April 13th, 2019 and 2020. With the additional onshore wind capacity, wind generation provides 50 to 60 MW of power throughout the day, as opposed to the negligible amount of power its provides during 2019. Solar generation levels also increase, peaking at around 200 MW in 2020 compared with 140 MW in 2019. The additional renewable generation causes the net-load to be negative for the day, indicating that there is excess dump energy which batteries can capture.

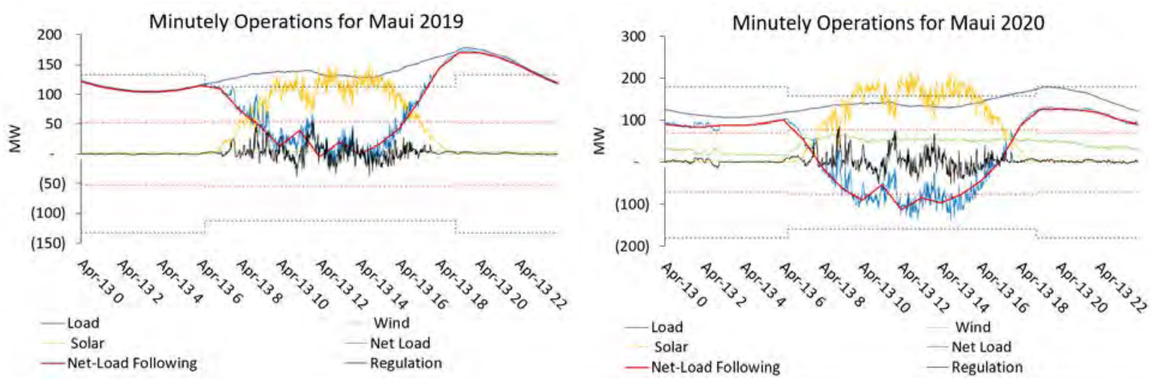


Figure 49: Side-by-side comparison of renewable generation, load and regulation requirements on April 13th, 2029 and 2030.

5.1.3. Hawaii Results

Since the Hawaii Post-April PSIP Plan only installs onshore wind, the percent increase of flexible generation requirements for Hawaii is the lowest of all the islands.

Year	Day-Time Regulation (95%)	Day-Time Regulation (99.9%) (A)	Contingent Reserve (B)	Max 15-Minute Ramp	Max 1-Hour Ramp (C)	On-Peak Total Flexible Generation (A+B+C)
2017	18	43	11	63	108	136
2018	19	44	12	63	109	139
2019	19	45	12	64	111	141
2020	20	48	12	62	111	142
2021	21	49	12	63	112	144
2025	21	50	12	63	113	145
2030	22	52	12	60	110	142[4]
2035	23	54	12	64	116	148

[4] The lower flexible generation requirements in 2030 relative to 2025 is a function of decreasing load.

2040	24	56	13	68	124	158
2045	25	59	14	73	132	172

Table 9: Hawai'i - renewable integration requirements for flexible generation. Unlike for Oahu, On-Peak Total Flexible Generation is calculated using Day-Time Regulation Requirement necessary to maintain a CPS2 score of 99.9, as opposed to 95.

In 2028, Hawaii plans to increase its on-shore wind capacity by 20 MW. Figure 50 offers a comparison of the difference in wind generation between 2029 and 2030.

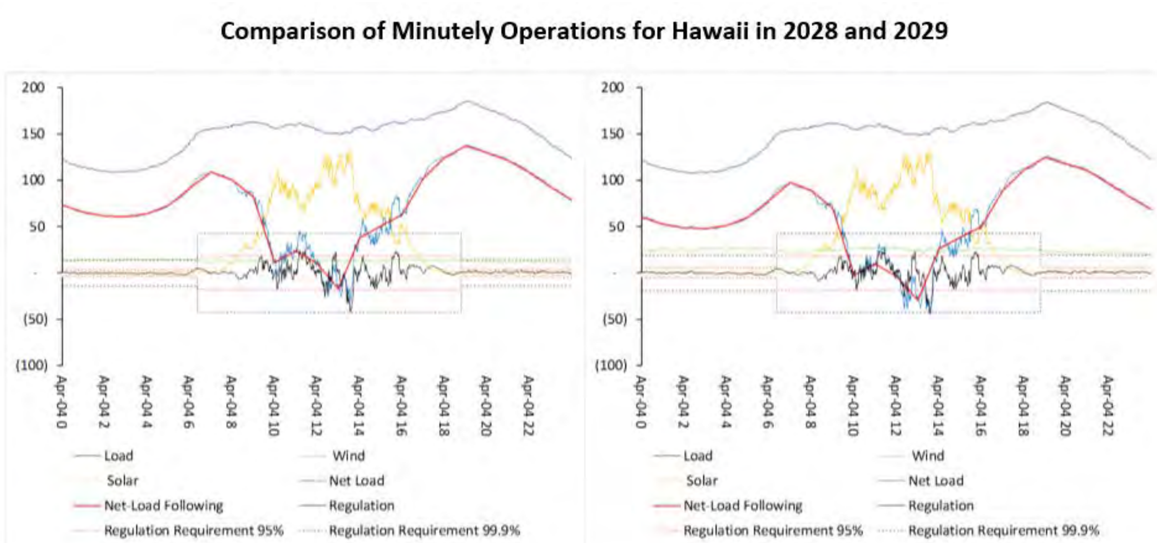


Figure 50: Side-by-side comparison of renewable generation, load and regulation requirements on April 4th, 2027 and 2028. April 4th, 2027 is depicted on the right and April 4th, 2028 is depicted on the left.

Figure 50 indicates that the expansion in wind capacity causes a slight increase in wind generation. This wind expansion does not have a drastic effect on regulation requirements: The regulation requirements from 2029 to 2030 increase by 1 MW.

5.2. Flexible Generation and Batteries

PowerSimm compares thermal generation to batteries and calculates the savings that could be realized through the use of batteries. PowerSimm takes regulation requirements, as determined by System Flexibility Software, as input and determines the most cost-effective way to meet those requirements. PowerSimm calculates not only the savings from using batteries to meet regulation requirements, but it also calculates the savings that can be realized by using flexible batteries to smooth out the sawtooth changes in the net-load gradient induced by renewable generation contributions and daily ramps.

First, this section will define the three different types of batteries presented in this report. Then, this section will discuss the use of batteries to meet regulation requirements. Lastly, this section will discuss the use of flexible batteries.

5.2.1. Three Types of Batteries

This report discusses three different types of batteries:

1) **Regulation batteries** are batteries that are used to meet regulation requirements, discharging and charging on a minutely scale to respond to minor fluctuations in load and generation. Ascend has assumed that regulation batteries have a seven-year lifetime due to their extremely frequent charging/discharging.
2) **Flexible batteries** are used to respond to daily cycles and ramps, discharging and charging on an hourly scale to smooth out changes in the net-load gradient induced by high levels of renewable generation. Ascend assumed that flexible batteries have a twelve-year lifetime due to their less frequent charging/discharging.
3) **Load-shifting batteries**, which have already been discussed in the larger report, are used to absorb excess renewable generation during the day and discharge that energy at night. Thus, load-shifting batteries charge/discharge on a daily scale. Ascend assumed that load-shifting batteries have a fifteen-year lifetime due to their rather infrequent charging/discharging.

While the advantages of load-shifting batteries were discussed in Section 4, this section focuses on the advantages of batteries to furnish flexible regulation and smooth out rapid changes in load following cycles.

5.2.2. Regulation Batteries

The benefits derived from regulation batteries consists of two key elements. The first is the avoided fuel cost that comes from using batteries to provide regulation services. Below, Figure 51 shows thermal units have a declining heat rate as generation increases. Thus, thermal units operate more efficiently as they run closer to full load capacity. When thermal units serve regulation, they operate below their full load capacity, at a heat rate close to the midpoint. Using batteries to provide regulation enables thermal generators to avoid operating at these inefficient levels and save fuel costs. Additionally, batteries have the potential to eliminate costly start-ups from thermal generation. For example, the start-up costs for a combustion turbine of 100 MW is approximately $8,000 dollars. Using batteries to furnish regulation instead can avoid these start-up costs.

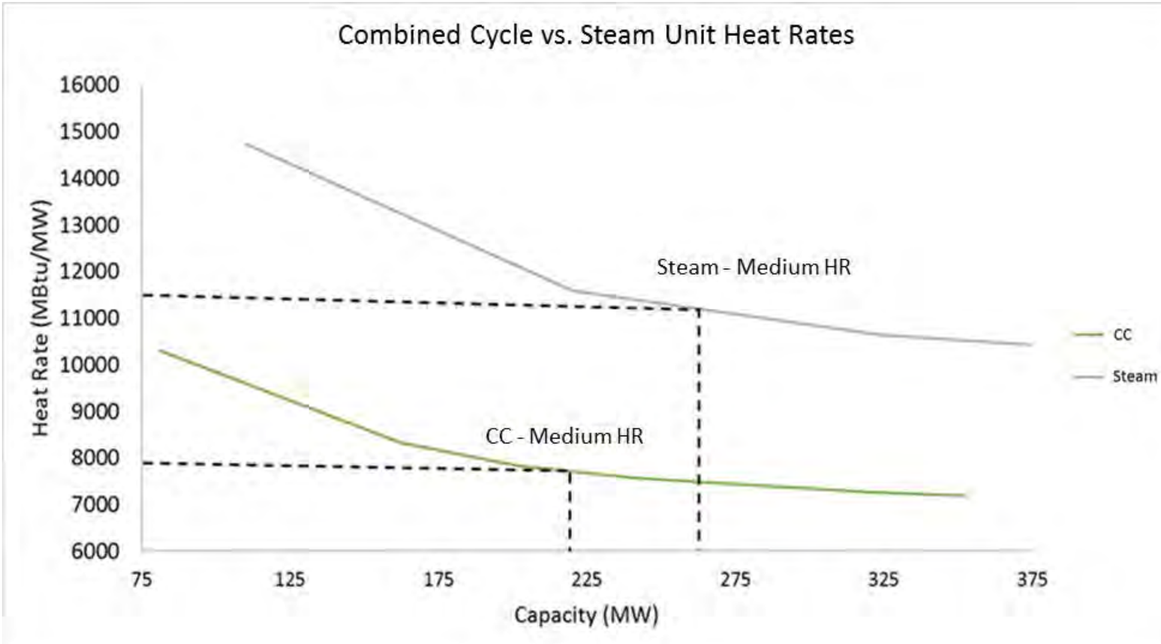


Figure 51: Typical heat-rate curve for combined-cycle and coal generators.

The second element of battery benefits is capacity savings. When batteries furnish regulation, they effectively free up thermal generation that would otherwise be used to serve regulation. This freed up thermal generation can then be diverted to serve capacity, and, in turn, run at more efficient levels.

To compare the supply cost of thermal regulation to the cost of installing regulation batteries for Oahu, the cost-savings calculations consider the levelized cost of regulation batteries. This calculation multiplies the required battery capacity by the effective capital cost of battery installation. This calculation assumes a seven-year lifetime for regulation batteries, and it also assumes that, after seven years, the batteries are worth 50% of the cost of installation at that time. The levelized cost calculation spreads the capital costs of batteries over a seven-year period with an eight percent interest rate. These calculations ultimately show that the supply cost of thermal regulation is consistently much greater than the levelized capital costs for installing regulation batteries. These results are shown below in Table 10 and Figure 52.

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Thermal Fuel Cost - ULSD ($/MMBtu)	$17.81	$19.55	$21.01	$22.25	$23.24	$24.14	$25.17	$26.39	$27.53	$28.61	$29.93	$31.02	$32.55
Regulation Requirements													
On-peak Regulation Requirement (GWh/yr)	392	499	506	640	652	824	838	850	860	873	886	903	916
Off-peak Regulation Requirement (GWh/yr)	80	88	88	88	88	88	88	88	88	88	88	166	166
Regulation Battery Capacity Requirements (MWh)	25	31	32	40	41	52	53	53	54	55	56	57	58
Regulation Costs and Savings													
Thermal Supply Costs to Provide Regulation ($M/yr)	($13)	($17)	($19)	($24)	($26)	($33)	($35)	($37)	($39)	($41)	($44)	($50)	($53)
Levelized Battery Costs - Regulation ($M/yr)	($2)	($2)	($2)	($3)	($3)	($4)	($4)	($3)	($3)	($3)	($3)	($3)	($3)
Savings From Batteries for Regulation ($M/yr)	$11	$15	$16	$21	$23	$29	$31	$34	$36	$38	$41	$47	$50

Table 10: PowerSimm calculation results for regulation battery savings for Oahu.

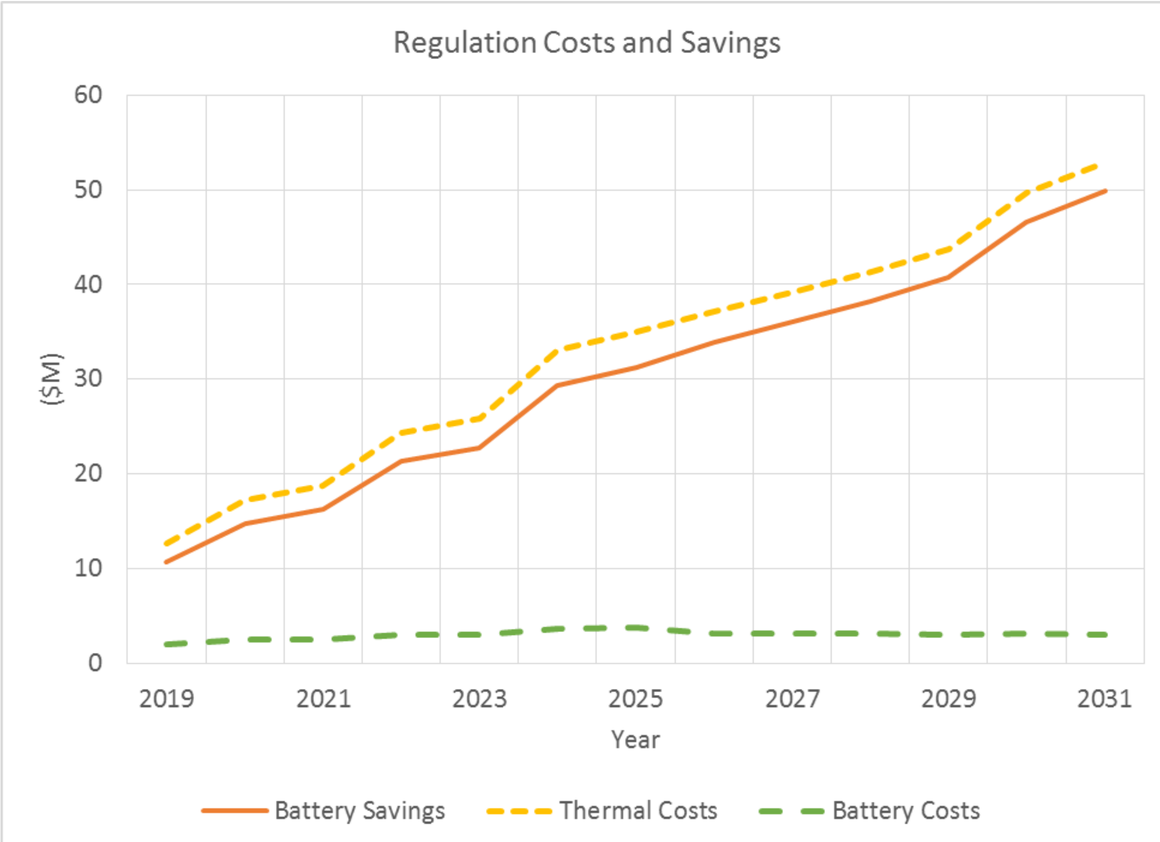


Figure 52: Early savings from using batteries for regulation instead of ULSD thermal generation.

As the above figure shows, regulation batteries offer a prompt reduction in costs upon the first year of their introduction. Over the course of six years, with their capacity approximately doubling, savings from regulation batteries nearly triples.

5.2.3. Flexible Batteries

While regulation batteries provide high-frequency and short-duration charges and discharges to balance the difference between generation and load, flexible batteries serve longer-duration but less frequent cycles. Flexible batteries are usually of a duration of a couple hours and geared toward smoothing out the sawtooth pattern in hourly net load, as well as meeting daily ramps. Flexible batteries provide cost savings by preventing thermal units from running at inefficient heat rates. These savings are further aided through utilizing free dump energy to meet ramps and cycles, instead of producing that energy with thermal generation.

To compare the supply cost of thermal generation to flexible batteries for Oahu, the fuel cost and start-up cost savings of flexible batteries are measured against the capital costs of flexible batteries. The levelized cost of flexible batteries are measured over an assumed life of twelve years with an eight percent interest rate. PowerSimm's calculations show that, starting in the year 2022, flexible batteries provide substantial savings over thermal generation. These results are presented below in Table 11 and Figure 53.

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Thermal Fuel Cost - ULSD ($/MMBtu)	$22.25	$23.24	$24.14	$25.17	$26.39	$27.53	$28.61	$29.93	$31.02	$32.55
Flexible Generation Requirements										
Ramp/Cycle Mgmt Energy Requirement (GWh/yr)	36	40	154	173	196	213	241	255	253	256
Dumped Energy (available for battery storage) (GWh/yr)	67	87	185	214	251	289	331	377	620	663
Battery Capacity Required for Ramp/Cycle Mgmt (MWh)	117	130	508	570	646	702	792	839	832	841
Flexible Generation Costs and Savings										
Thermal Supply Costs to Provide Ramps/Cycle Mgmt ($M/yr)	($2)	($2)	($7)	($9)	($10)	($12)	($14)	($15)	($16)	($16)
Thermal Gen Costs to Produce Dumped Energy ($M/yr)	($7)	($8)	($34)	($39)	($47)	($53)	($62)	($69)	($71)	($75)
Total Thermal Costs (Dump Energy Generation + Ramp/Cycle Mgmt) ($M/yr)	($9)	($10)	($41)	($48)	($57)	($65)	($76)	($84)	($86)	($91)
Levelized Battery Costs - Ramp/Cycle Mgmt ($M/yr)	($5)	($6)	($22)	($25)	($28)	($30)	($34)	($34)	($34)	($34)
Savings From Batteries for Flexible Generation ($M/yr)	$4	$4	$19	$23	$29	$34	$42	$50	$52	$57

Table 11: PowerSimm calculation results for flexible battery savings for Oahu.

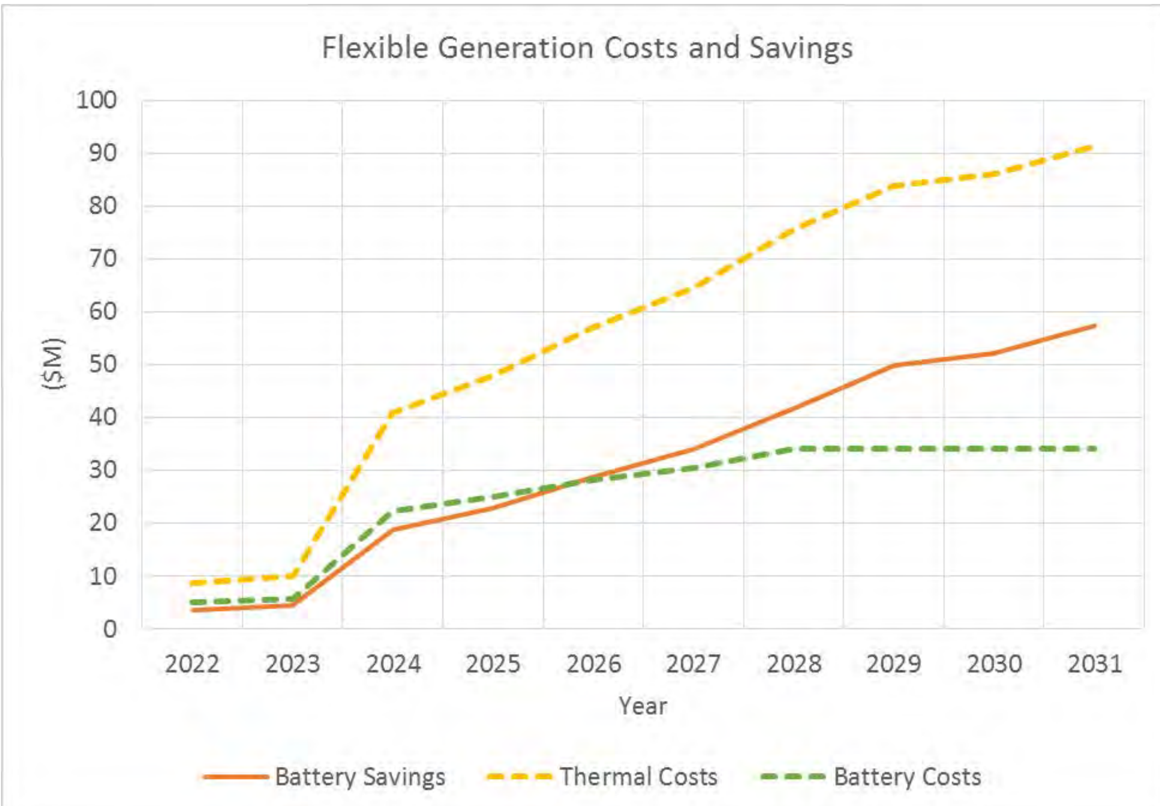


Figure 53: Yearly savings from using batteries for flexible generation instead of ULSD thermal generation.

Figure 15 indicates that, upon an introduction of flexible batteries into the energy system by 2022, flexible batteries provides an immediate reduction in costs, though not to the same extent as regulation batteries. By 9 years after their introduction, increased use of flexible batteries can save $57 million per year.

6. Addendum A: Incorporating Uncertainty in Resource Selection

Since the Companies have an obligation to minimize future costs, it is essential to analyze different energy supply options under many possible future conditions. While traditional modeling approaches utilize "normal" weather years and smooth fuel price trajectories, evaluating energy supply options under this single set of future conditions will almost certainly not reveal the lowest-cost energy supply portfolio over *all* future conditions. PowerSimm stochastically simulates future conditions, including market fuel prices and weather conditions, which drive renewable generation and load. Thus, PowerSimm provides a systematic approach for selecting the lowest-cost energy supply option over a broad range of future conditions. In addition, by simulating a range of future conditions, PowerSimm is able to quantify the risk associated with a particular energy supply option. This section will, first, elucidate the way in which PowerSimm simulations can be utilized to select the best energy supply option over all future conditions, and second, how PowerSimm quantifies the risk associated with a particular energy supply portfolio.

6.1. Stochastic Modeling and Optimal Resource Selection

The PowerSimm capacity expansion logic selects from an array of thermal and renewable assets to provide an evaluation of the optimal mix of these two types of assets. To perform this optimization, the

PowerSimm modeling framework probabilistically envelopes future conditions to aid in optimal resource selection over all future states. Although Ascend could utilize deterministic runs with a single set of future conditions to assess the value of different supply portfolios, such an approach would ignore volatility and uncertainty in crucial variables, such as weather and fuel prices. For example, Figure 54 displays five PowerSimm-simulated Oil price trajectories through 2028. This figure demonstrates how Ascend's PowerSimm software uses multiple simulations of driving variables to probabilistically envelope future conditions.

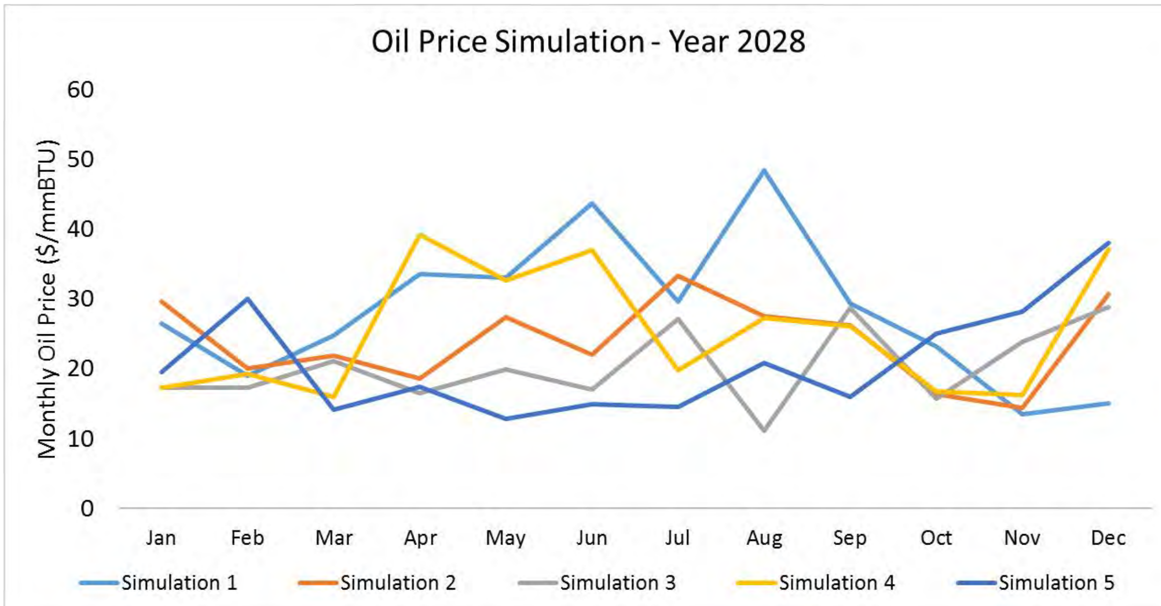


Figure 54: Five PowerSimm simulations of oil prices through 2028.

Thus, Ascend has found that deterministic runs can bias modeling results because of their limited path into the future. Instead, by simulating these variables, Ascend can assess the value of supply portfolios over a broad range of future conditions, and in turn, Ascend can determine which supply portfolios perform the best over all future conditions. Below, Figure 55 illustrates the difference in results between a deterministic run and a stochastic simulation that envelopes a range of future states.

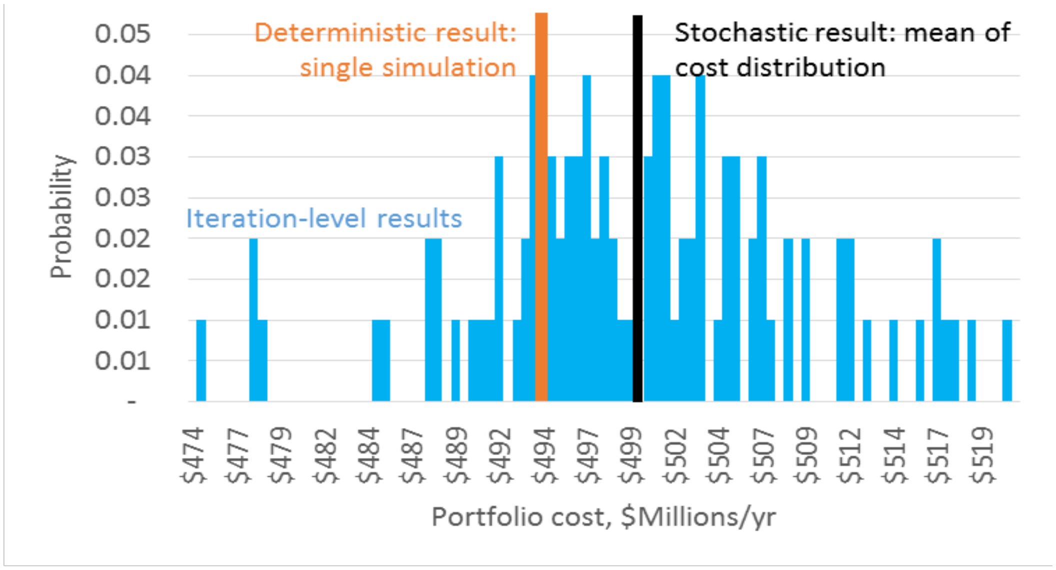


Figure 55: Distribution of iteration-level results used to find stochastic result, versus deterministic result

In Figure 55, the deterministic result yields only one portfolio cost value. However, many stochastic simulations yield a distribution of portfolio cost values with a mean portfolio cost that differs from the deterministic result. The deterministic result is biased by user-determined weather conditions and fuel prices, whereas the stochastically-simulated mean reflects a wide range of future conditions. In this way, the PowerSimm framework can be used to develop unbiased results that take uncertainty into account.

To further illustrate this point using Figure 56, Ascend draws a sporting analogy for resource selection under uncertainty. Selecting the optimal energy portfolio over a deterministic run is equivalent to finding the best swimmer (Michael Phelps), the second deterministic run finds the best cyclist (Chris Froom), and the third deterministic run finds the best runner (Ryan Hall). However, in resource planning, we do not want the best athlete for any individual event, but the best athlete over all events – the best triathlete (Dave Scott). In the same way that the triathlete performs the best over multiple athletic events, the optimal energy portfolio performs the best over a wide range of future conditions. PowerSimm simulates this wide range of future conditions, allowing for the selection of the energy portfolio that performs best over all future conditions.

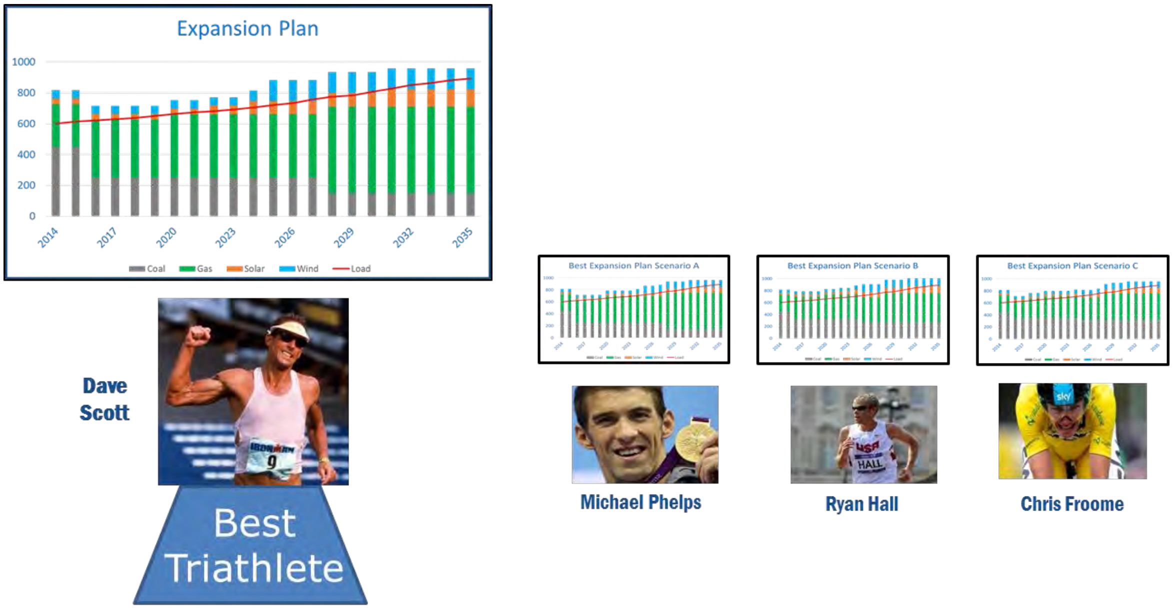


Figure 56: PowerSimm determines which athlete (resource expansion plan) is best over all sporting events (future simulated conditions)

6.2. Calculating Risk Premium

Not only does PowerSimm aid in the selection of the optimal energy portfolio over a wide range of future conditions, but PowerSimm also identifies the risk associated with each energy portfolio option, quantifying this as the "risk premium." The risk premium is defined as the probability-weighted average of costs above the median. This concept is illustrated below in Figure 57.

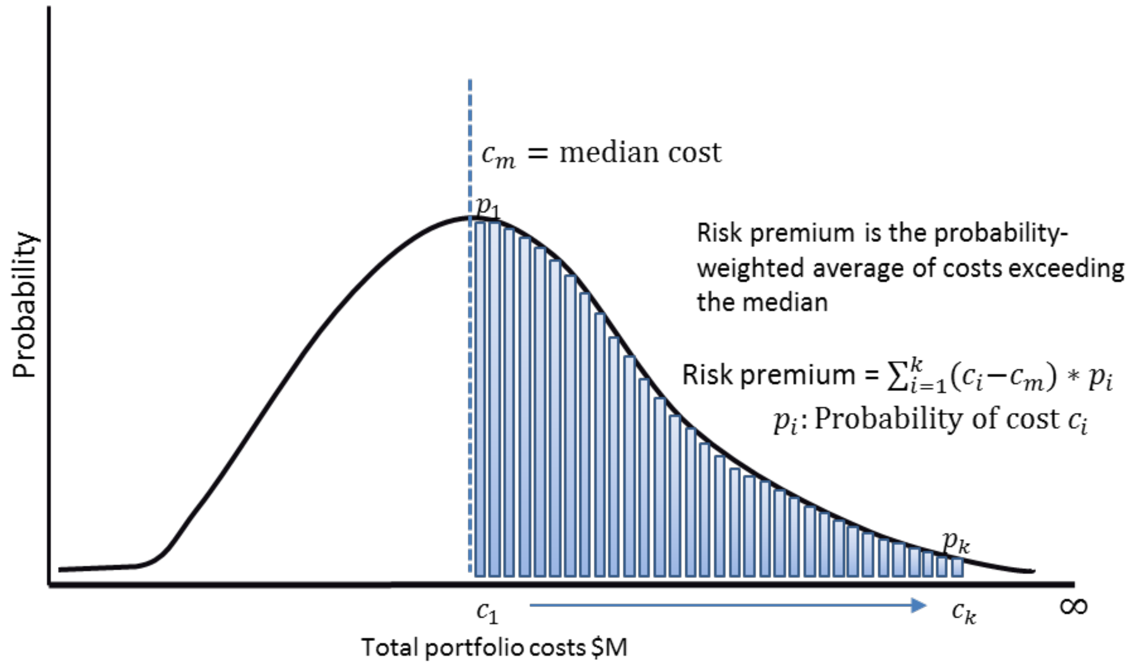


Figure 57: Risk Premium calculation

Since different energy portfolios have different simulated cost distributions, the risk premium will be larger for wider cost distributions, or riskier portfolios, and smaller for narrower cost distributions, or less risky portfolios. After calculating the risk premium, Ascend then adds the risk premium variable to the expected value in order to put all energy portfolio options on the same playing field.

6.3. Simulation Validation Tool

An energy system has to be prepared to not just confront normal weather conditions, but abnormal ones as well. Thus, PowerSimm accounts for a wide variability in possible future weather conditions and its consequent effects on load and generation. The following figures from the Simulation Validation Tool provide insight into the variability covered by PowerSimm.

The validation tool enables the user to scroll through time to view the variation in generation between four distinct weather simulations, as well as the average generation of total weather simulations run by PowerSimm.

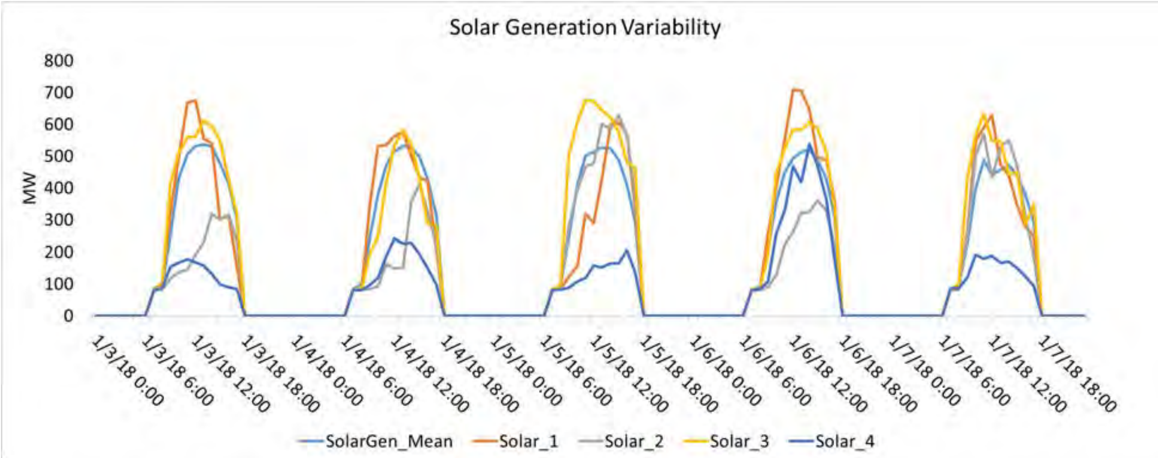


Figure 58: Solar generation over 4 different weather scenario from January 3rd to th 7th, 2018.

Figure 58 presents solar generation over a five-day period. The Solar 4 simulation, indicated by the dark blue line, represents a scenario where solar generation is particularly low. During this period, the mean generation of the 20 distinct simulations of solar generation, represented by the light blue line, can be up to 3 times larger than the generation of the Solar 4 simulation.

Figure 59 provides an example of the variation in solar generation at a later time, in 2045. The dark blue line shows an abnormal weather scenario, over a two-day period, when solar generation is two to three times lower than for the average of the total scenarios.

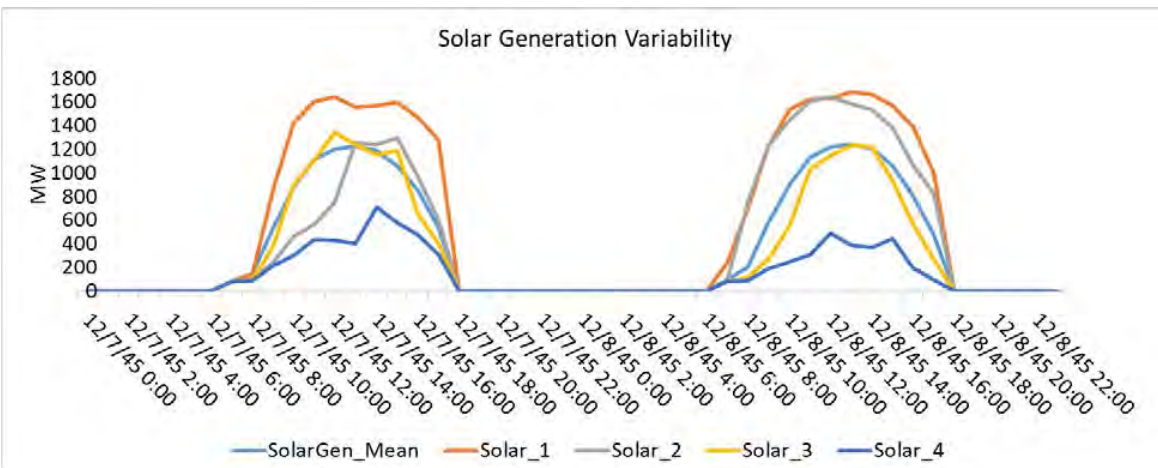


Figure 59: Solar generation over different weather scenarios from December 7th to December 8th, 2045.

Figure 60 presents wind generation for a day in 2029, illustrating that the difference in generation between the 4 distinct weather simulations can vary by up to 500%.

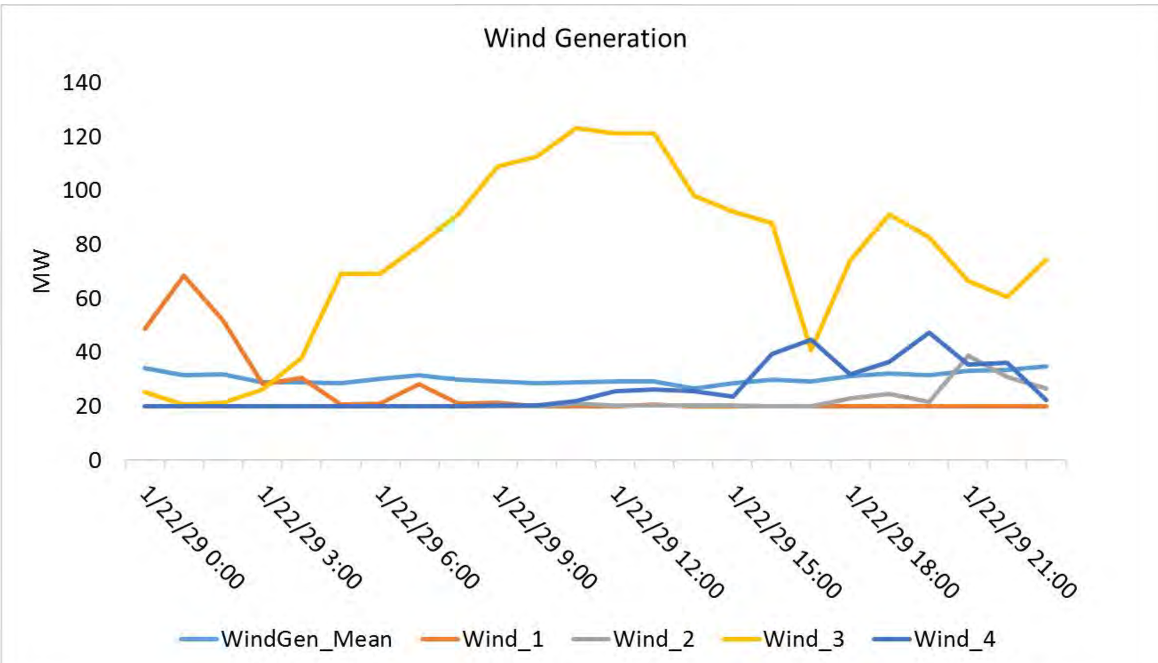


Figure 60: Wind generation over 4 different weather scenarios for January 22nd, 2029.

With the introduction of offshore wind in 2030, some of the variability in wind generation is mitigated, as offshore wind provides a more reliable source of generation than onshore wind. Figure 61 displays this lower variation.

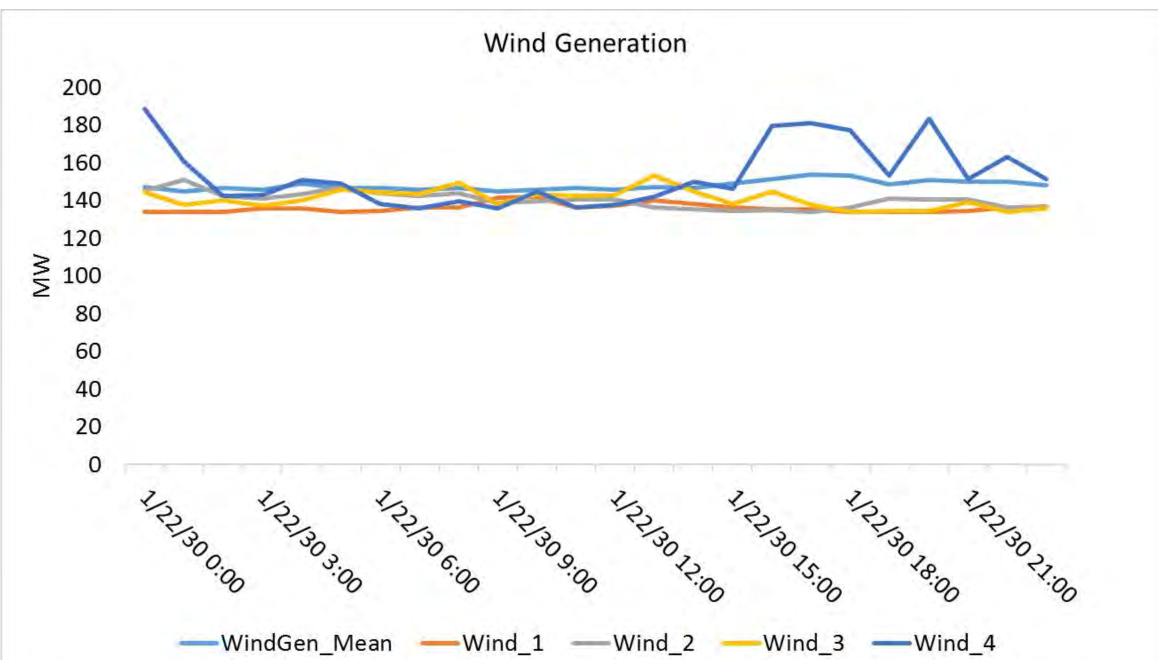


Figure 61: Wind generation over 4 different weather scenarios for January 22nd, 2030.

Thus, as these figures show, PowerSimm incorporates a substantial amount of variability within its inputs. This variability enables PowerSimm to provide results that take into account normal weather scenarios, as well as extreme weather scenarios

7. Addendum B: Model Inputs

With the PowerSimm modeling analysis, Ascend was able to further refine and optimize Oahu's original plans. As part of this process, Ascend utilized new data and added new features to Oahu's themes. Ascend has updated numerous forecasts and used these new forecasts as inputs to the PowerSimm model. This section will discuss updates to fuel forecasts, renewable forecasts, and customer load forecasts.

7.1. Fuel Forecasts

The United States Energy Information Administration (EIA) released a new fuel price forecast which has been included in Ascend's analysis. This forecast included significantly higher oil prices but unchanged LNG prices from the forecast which was used to develop the original themes. Figure 62 shows the forecasted fuel prices used in Ascend's modeling analysis.

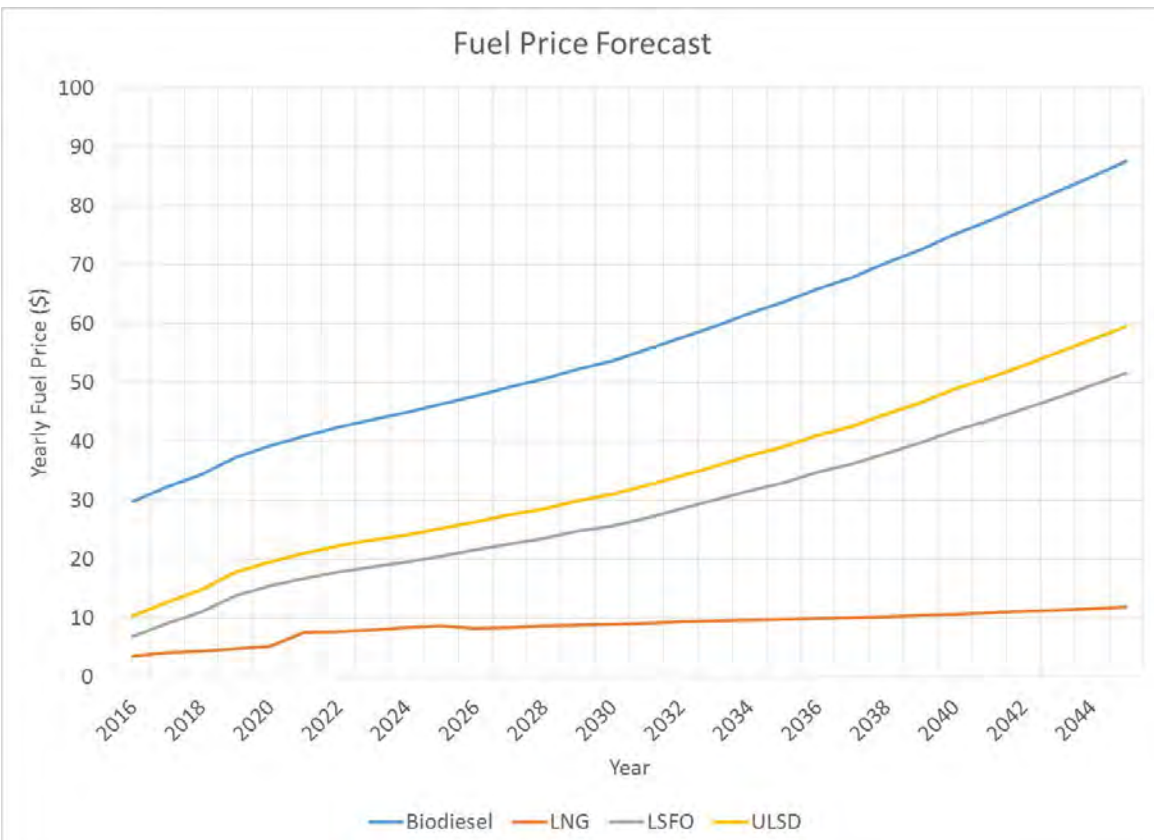


Figure 62: Fuel price forecasts used in PowerSimm modeling

As shown in Figure 62, LNG is the lowest-priced fuel, especially in the later decades of Ascend's analysis. LSFO and ULSD are priced much higher than LNG, and biodiesel is the most expensive fuel of all.

7.2. Renewable Forecasts

In addition to updated fuel forecasts, Hawaiian Electric Companies also provided Ascend with new unitized offshore wind data and new unitized photovoltaic data which were used to create an updated offshore wind forecast and an updated photovoltaic forecast. The new offshore wind data resulted in a forecast with higher offshore wind capacity than previous calculations. Whisker plots for Oahu's solar and wind generation are both shown below.

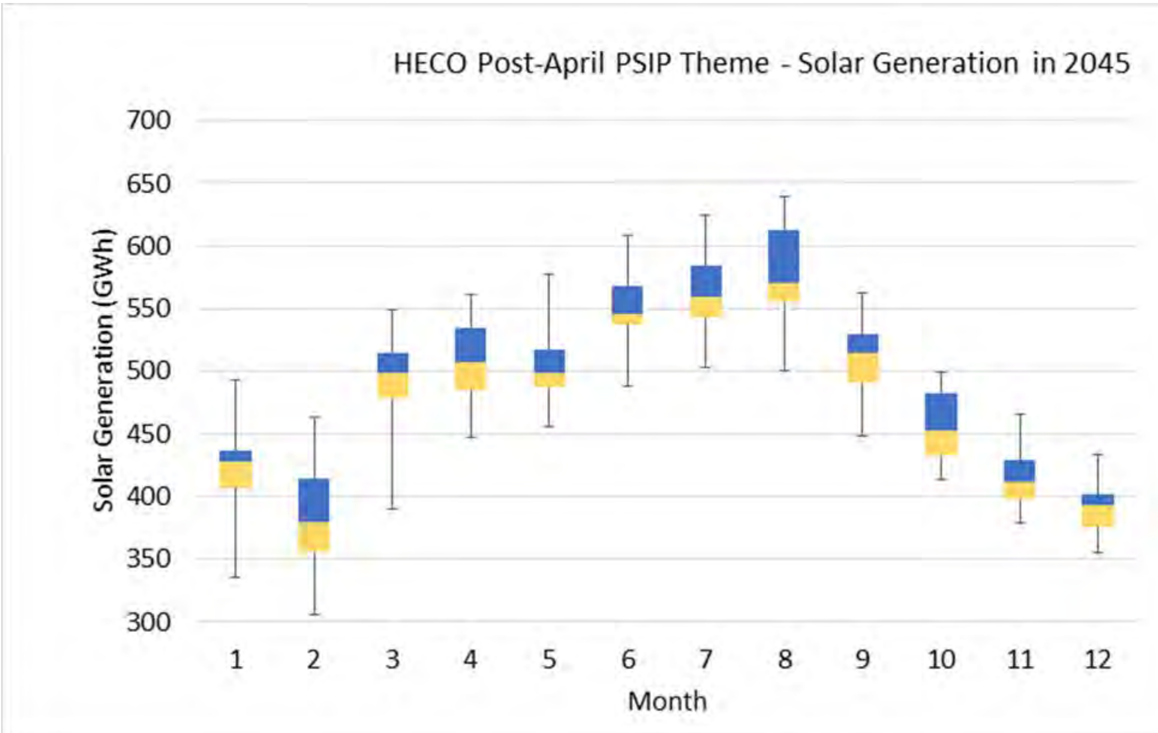


Figure 63: Oahu Theme 1 solar generation in 2045. Boxes span from 1st to 3rd quartile, with median in the middle. Whiskers cover the minimum and maximum simulated values.

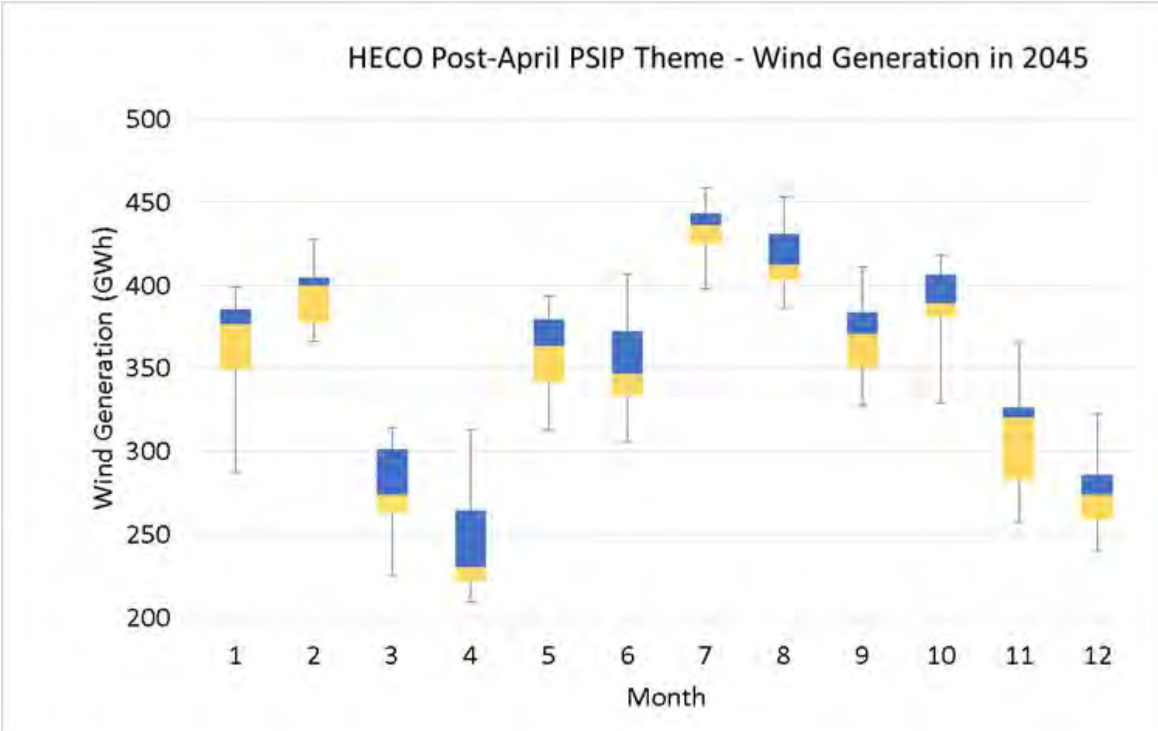


Figure 64: Oahu Theme 1 wind generation in 2045. Boxes span from 1st to 3rd quartile, with median in the middle. Whiskers cover the minimum and maximum simulated values. Update

7.3. Customer Load Forecast

With the creation of an updated hourly customer load profile based on the Black & Veatch DR5 forecast, Ascend included this new load profile in its PowerSimm model. The monthly customer load forecast for Oahu in 2045 is shown below in Figure 65.

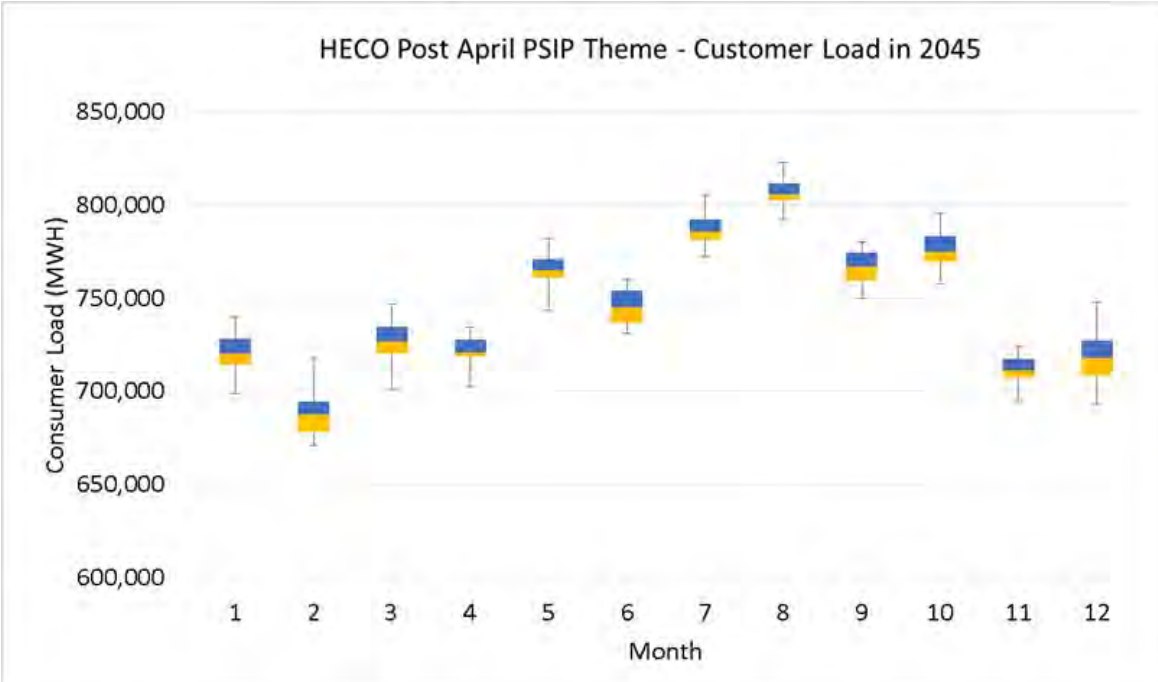


Figure 65: Oahu Theme 1 Black & Veatch DR5 customer load profile in 2045. Boxes span from 1st to 3rd quartile, with median in the middle. Whiskers cover the minimum and maximum simulated values.

8. Addendum C: Model Validation

To confirm that Ascend's PowerSimm model is valid, Ascend compared simulated weather, load, and renewable generation data to historical data to ensure that they match. In addition, Ascend also compared generation capacity factors to Oahu's values and simulated prices to forward data. The validation checks are shown in Table 12.

Validation	Completed
Weather	• Benchmark 5th, mean, 95th of historical temperatures
Load	• Hourly load: 5th, mean, 95th • Monthly load: 5th, mean, 95th
Renewables	• Hourly generation: 5th, mean, 95th
Generation Capacity Factors	• Match existing dispatch
Forward Curves	• Match 5th, mean, 95th of option ranges and expectation • Match option quotes of CME contracts

Table 12: Validation checks performed by Ascend to verify model accuracy

Ascend conducted this validation process for Oahu, Maui, and Hawaii, which will be discussed in this subsection in turn. But first the Ascend's Validation Tool will be reviewed.

8.1.1. Oahu Validation

Validation plots for Oahu weather, load, renewable generation, generation capacity factors, and forward curves are shown below. The following plots illustrates the agreement between

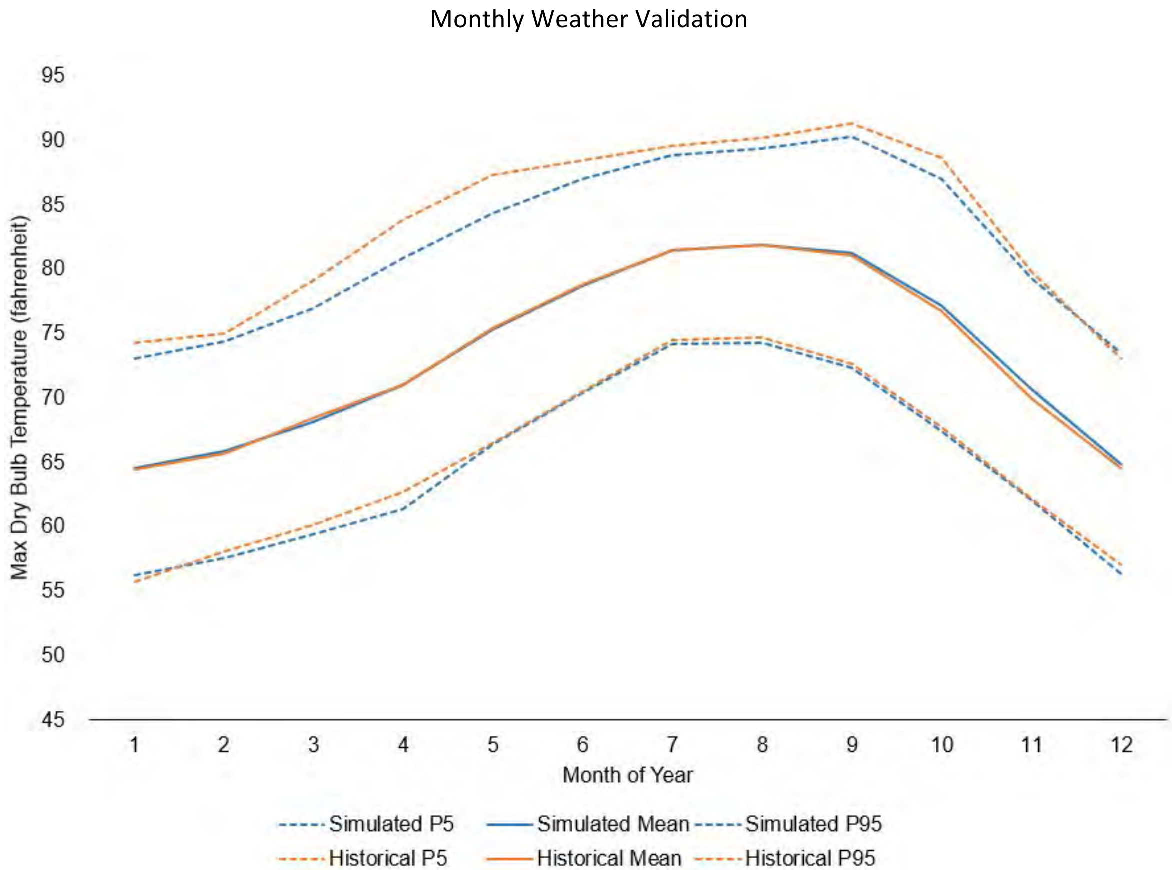


Figure 66: Shows that the historical weather data matches simulated weather data on the monthly level

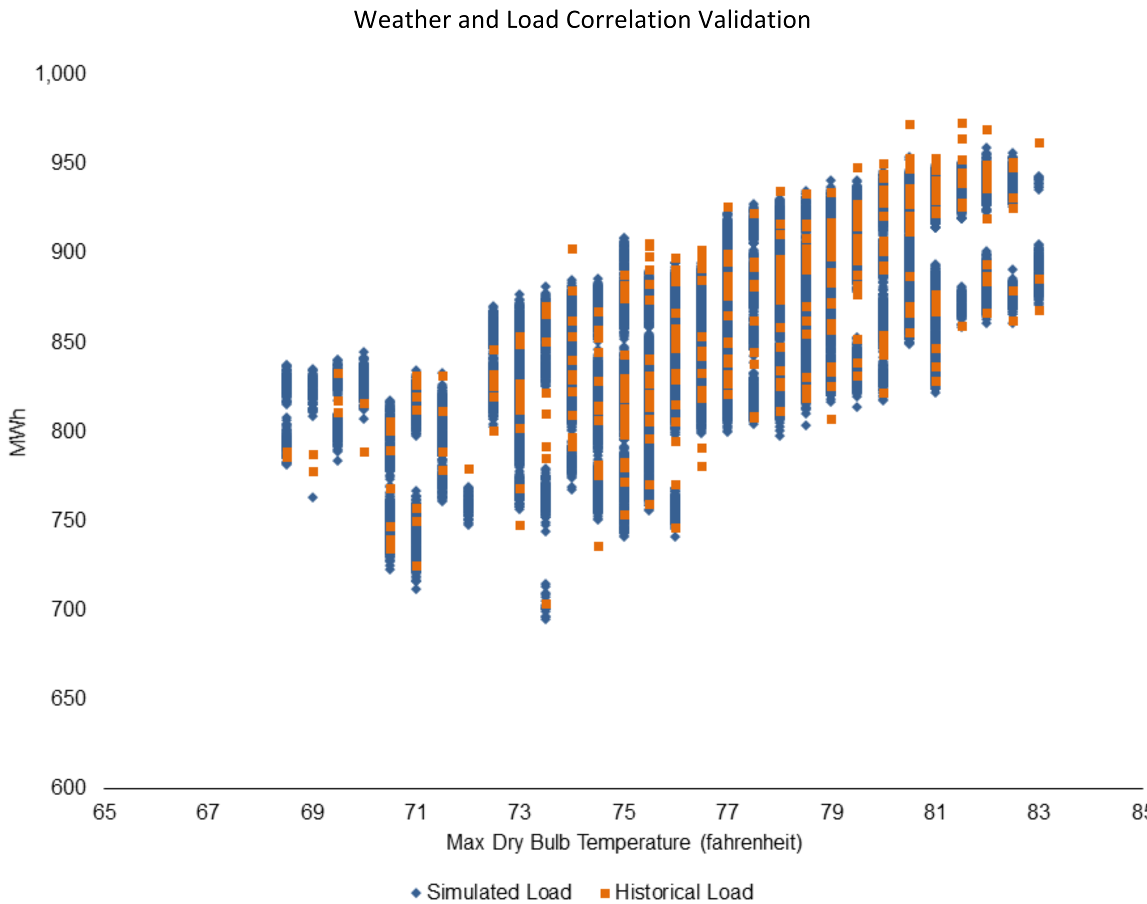


Figure 67: Shows that simulated weather and load data maintains the same relationship as historical weather and load data

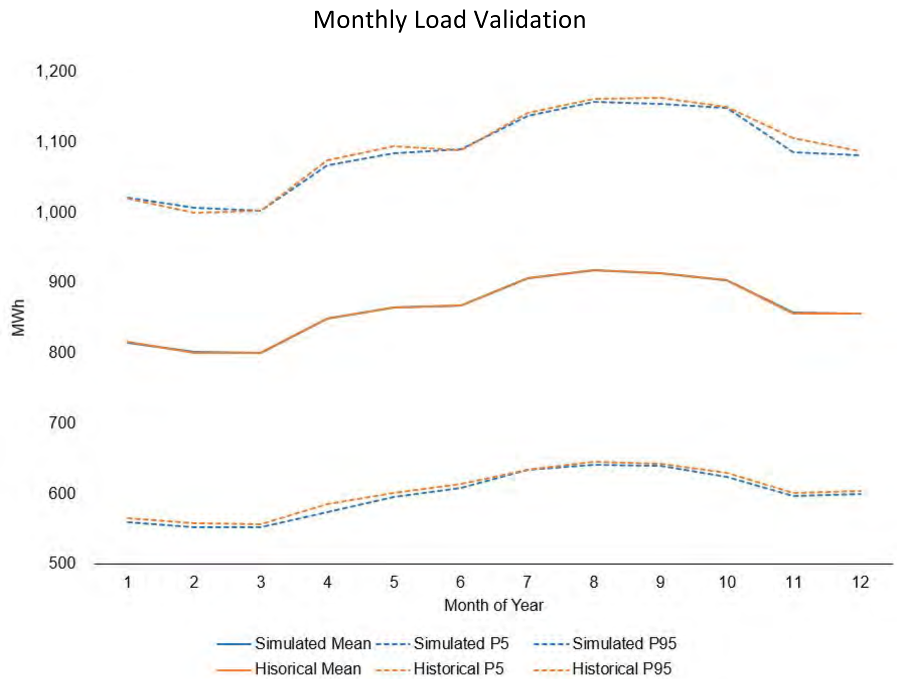


Figure 68: Shows that historical load data matches simulated load data on the monthly level

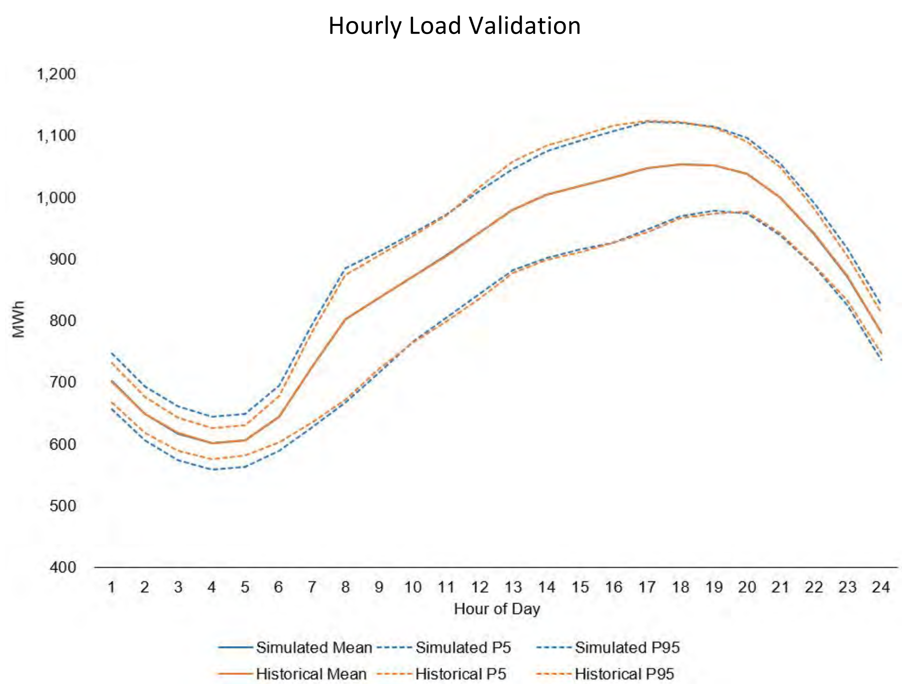


Figure 69: Shows that historical load data matches simulated load data on the hourly level

Hourly Solar Generation Validation

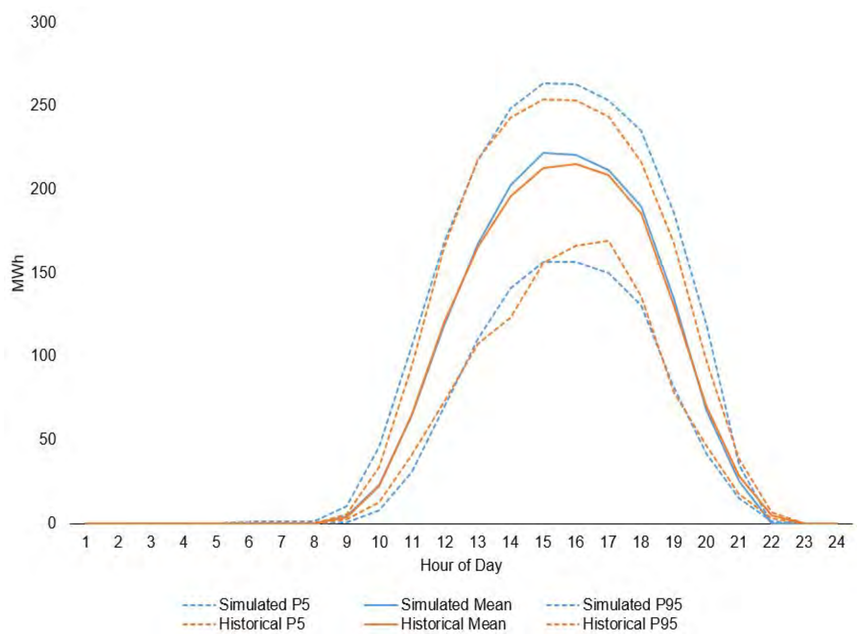


Figure 70: Shows that historical solar generation matches simulated solar generation on the hourly level

Generation Capacity Factor Validation

Generation Station	Ascend Capacity Factors	OAHU Capacity Factors
AES	0.91	0.93
CHEV	0.09	0.13
CIP	0.04	0.02
DSG	0.04	0.04
HIE	1.00	0.97
HP	0.53	0.43
Kahe	0.54	0.46
Kala CC	0.77	0.80
Waiau	0.13	0.17

Table 13: Shows that the Ascend generation capacity factors match the Oahu generation capacity factors

Fuel Price Forecast Validation

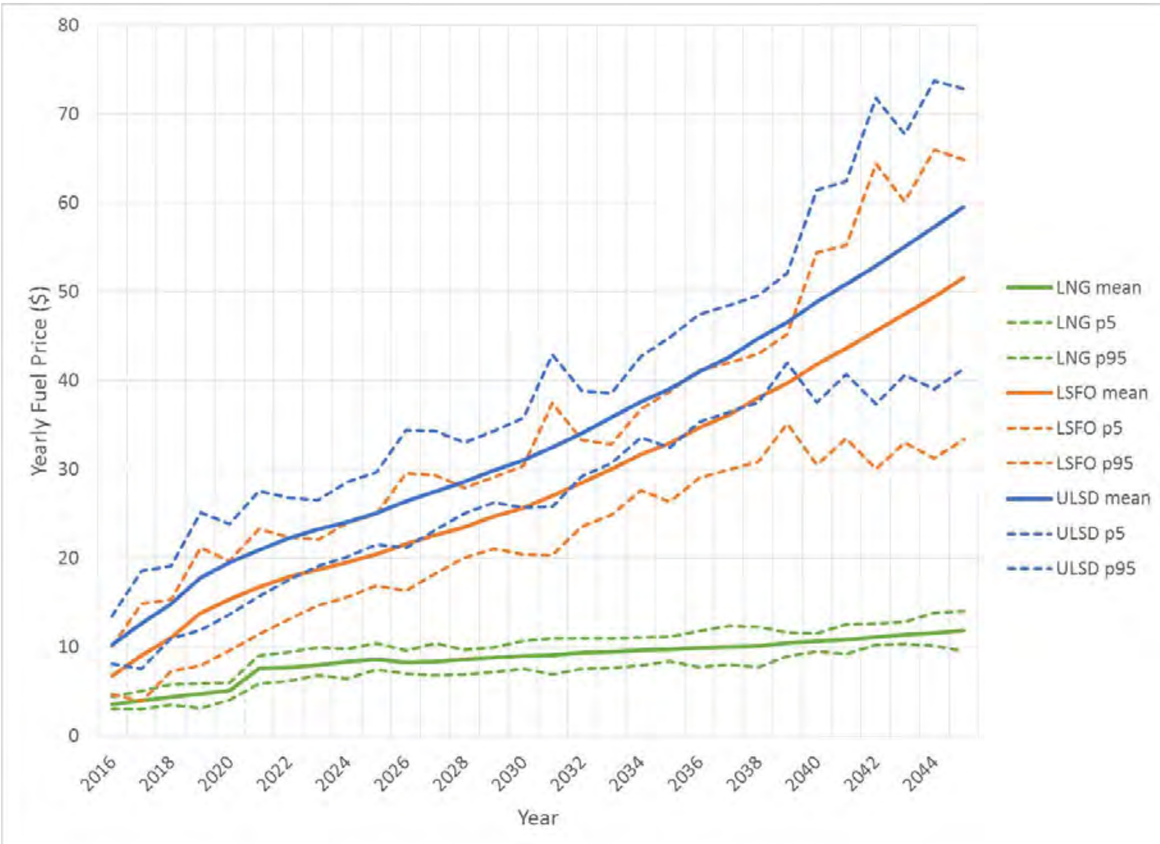


Figure 71: Shows simulated LNG, LSFO, and ULSD prices

8.1.2. Maui Validation

Validation plots for Maui weather and load are shown below.

Weather Validation

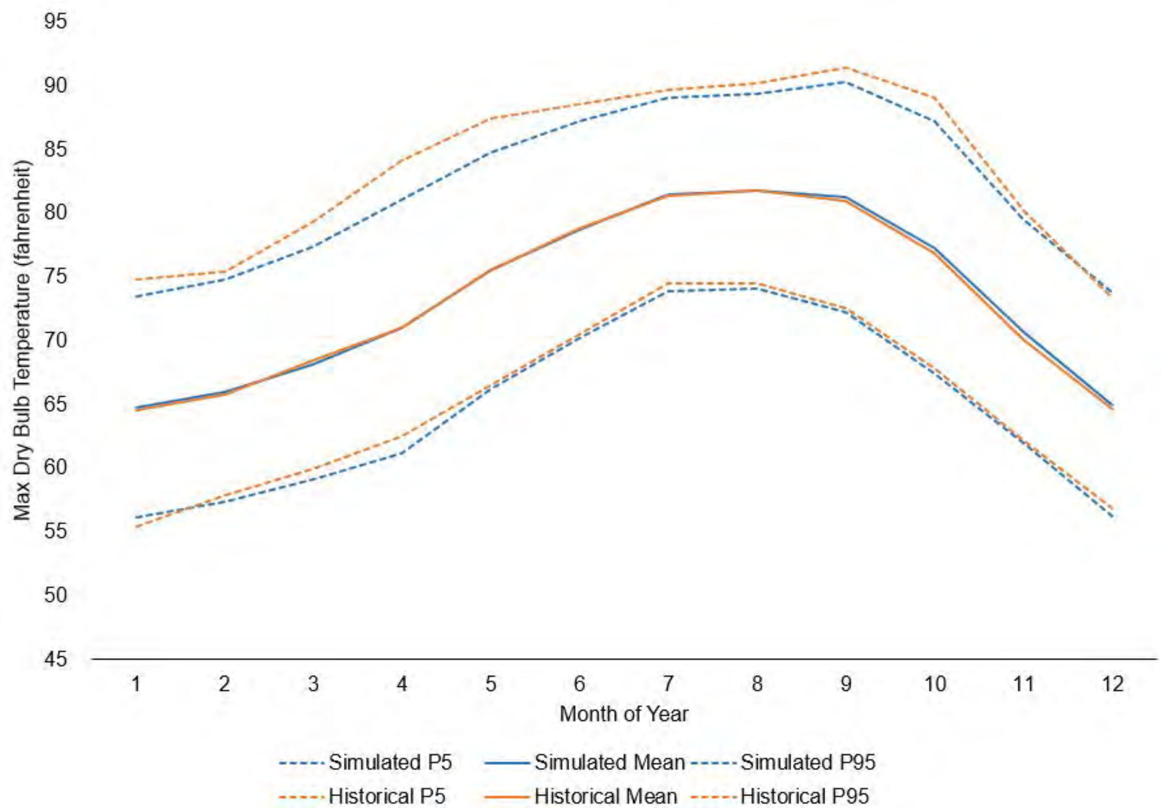


Figure 72: Shows that the historical weather data matches simulated weather data

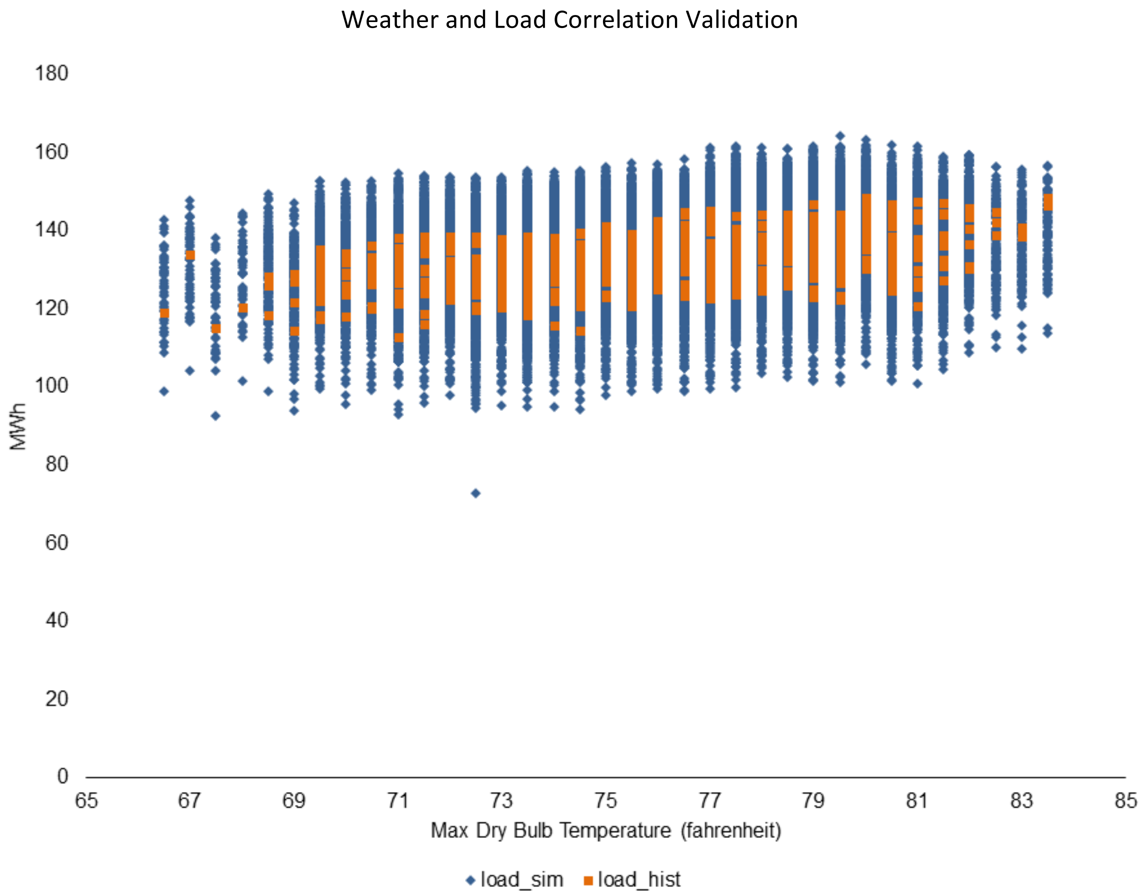


Figure 73: Shows that simulated weather and load data maintains the same relationship as historical weather and load data

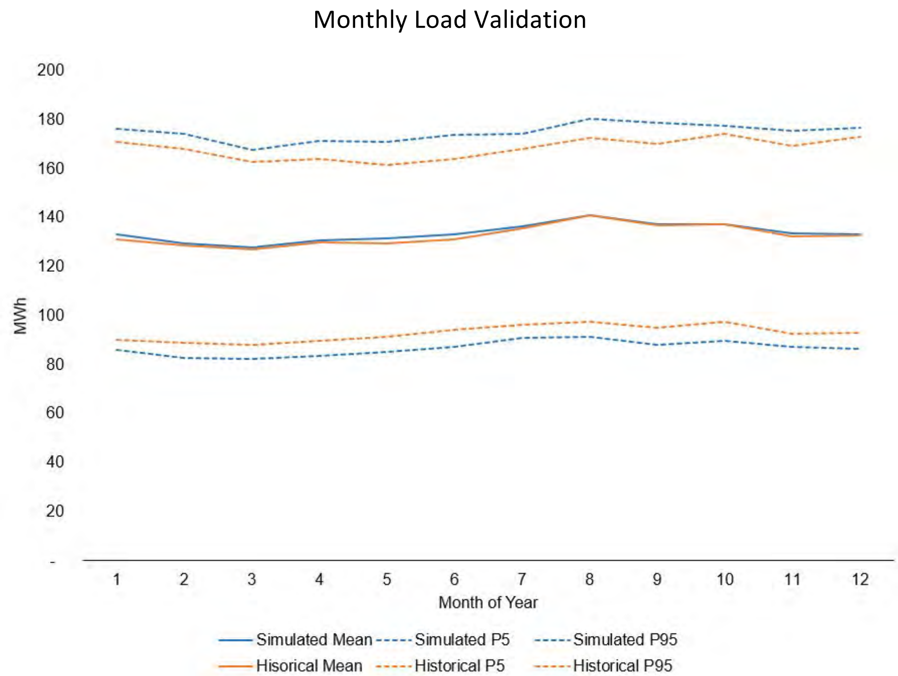


Figure 74: Shows that historical load data matches simulated load data on the monthly level

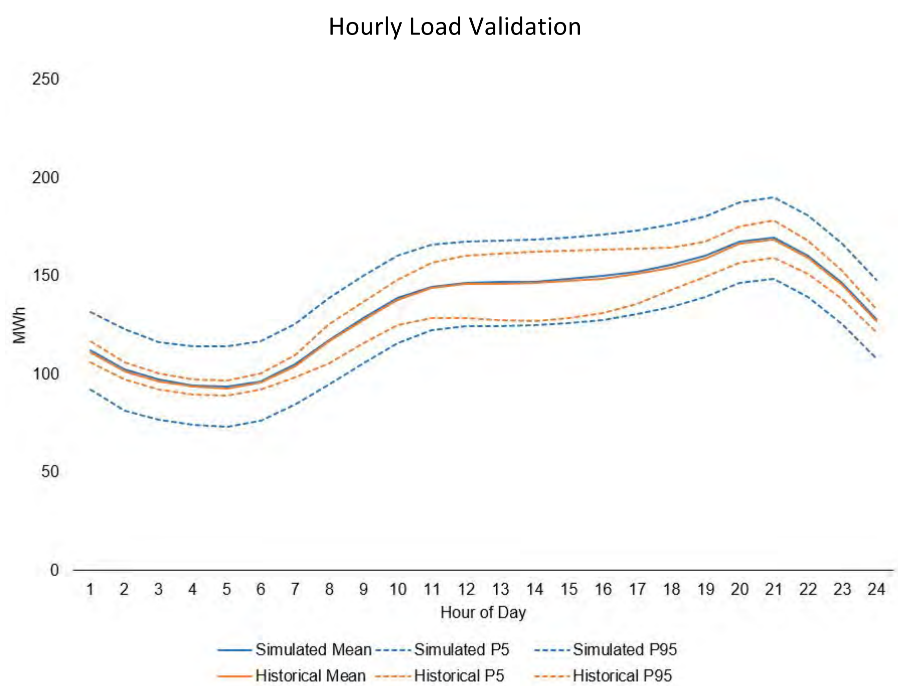


Figure 75: Shows that historical load data matches simulated load data on the hourly level

8.1.3. Hawaii Validation

Validation plots for Hawaii weather and load are shown below.

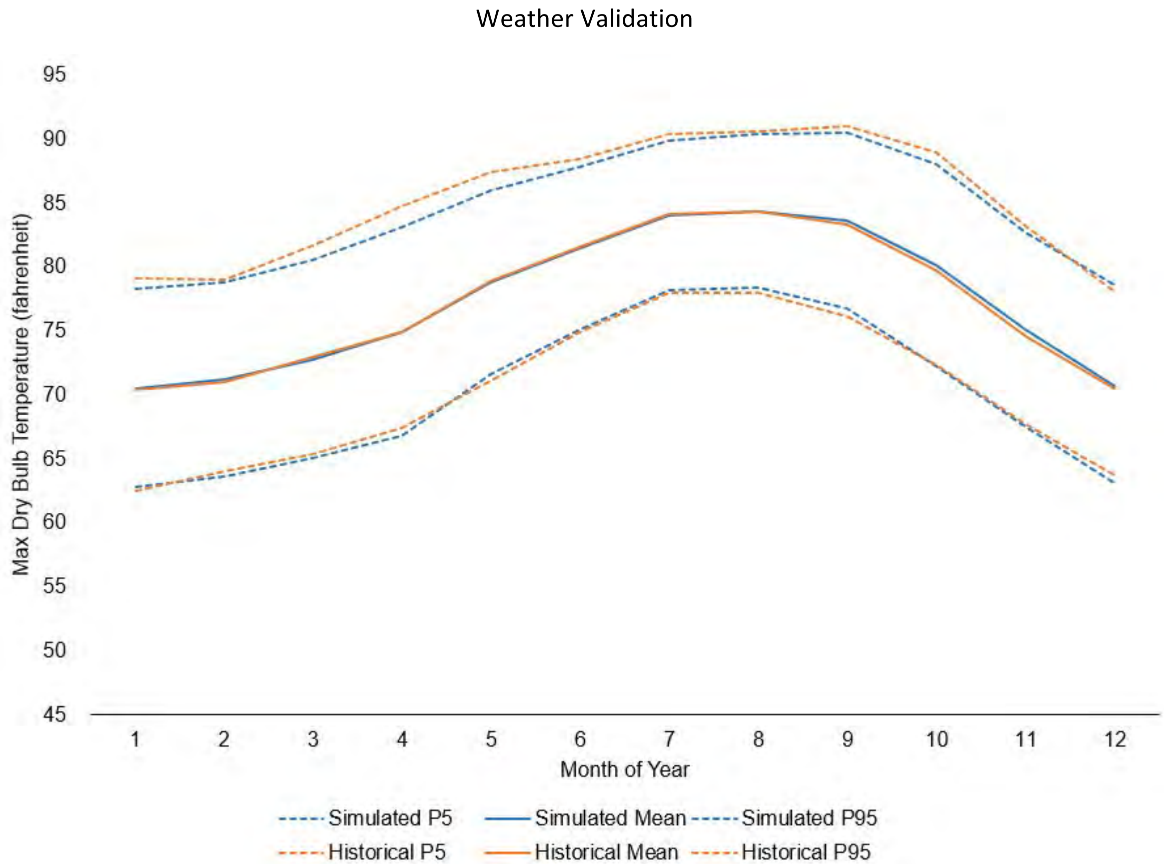


Figure 76: Shows that the historical weather data matches simulated weather data

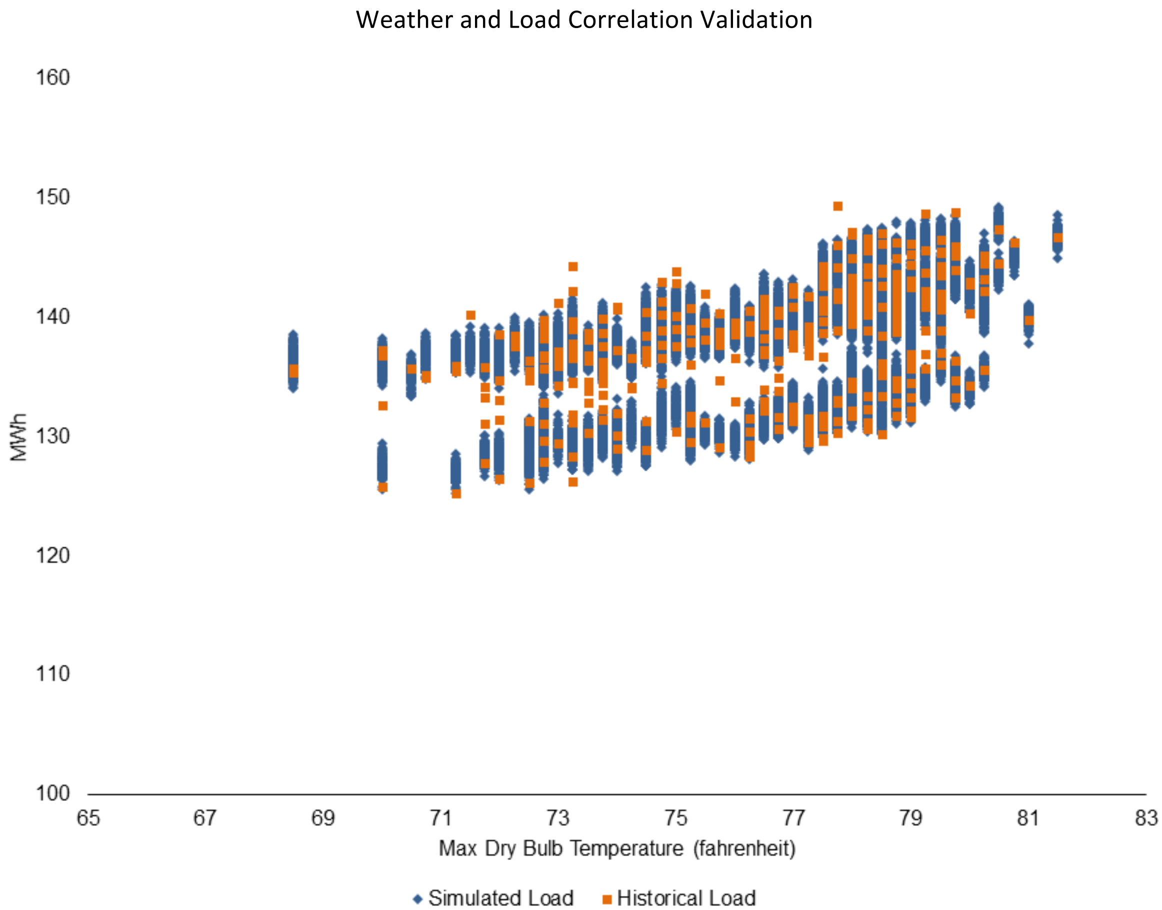


Figure 77: Shows that simulated weather and load data maintains the same relationship as historical weather and load data

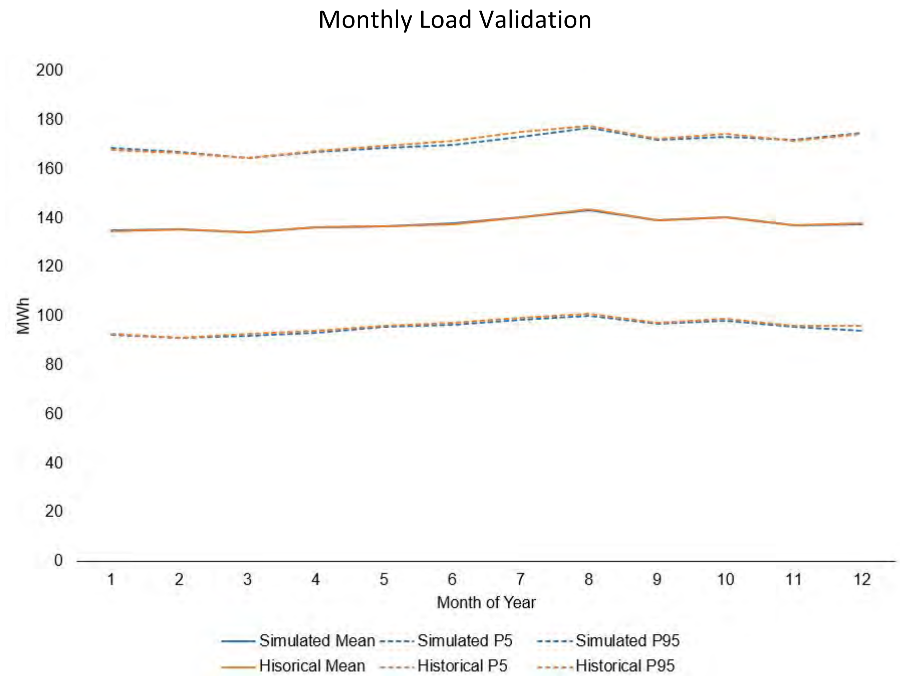


Figure 78: Shows that historical load data matches simulated load data on the monthly level

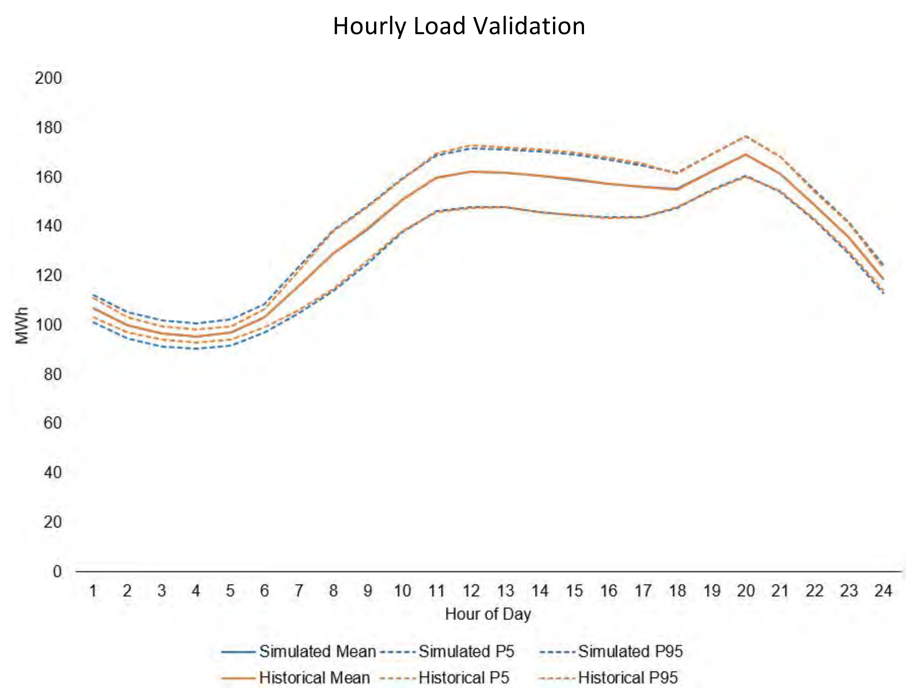


Figure 79: Shows that historical load data matches simulated load data on the hourly level

9. Addendum D: Data for System Flexibility Software

Minutely data for System Flexibility Software was collected or proxied for each island for Load, Utility Solar, Customer Solar, On-Shore Wind, and Off-Shore Wind. Each island has 3 themes, with separate forecasts and assumptions corresponding to each.

Oahu

Load	Minutely data for O'ahu net load was shared from January 2014 through October 2015. This load data has a small amount of DGPV netted out of it.
Utility PV	Minutely Data for KREP and KS2 were summed from January 2014 through October 2015.
Customer PV	Unitized minutely profile for DGPV for 2014, provided by HECO.
On-Shore Wind	Minutely data for Kahuku and Kawailoa were summed from January 2014 to October 2015. Starting in 2035, Kahuku and Kawailoa were summed with themselves lagged 28 days (one lunar cycle) to represent increased spatial diversity.
Off-Shore Wind	Two-Second data for HRD was aggregated to minutely in April, August, and December 2014 and used as a proxy for off-shore wind due to similar capacity factors and correlation to On-Shore wind.

The overlapping time intervals for the above historical data was used for this analysis. Overlapping data existed for 3 months in April, August, and December 2014. Annual forecasts for each theme (1-3) contain separate Utility Solar, Customer Solar, On-Shore Wind, and Off-shore Wind Capacity assumptions, and Must-Run Thermal Generation Constraints. Load forecasts are constant between themes.

Hawaii

Load	HELCO shared a 2 second system load profile that was aggregated to minutely in April, August, and December 2014.
Utility PV	HELCO shared a 2 second PV profile that was aggregated to minutely in April, August, and December 2014.
Customer PV	HELCO shared a 2 second PV profile that was aggregated to minutely in April, August, and December 2014.
On-Shore Wind	Two-Second data for HRD and Tawhiri were aggregated to minutely in April, August, and December 2014.

The overlapping time intervals for the above historical data was used for this analysis. Overlapping data existed for 3 months in April, August, and December 2014. Annual forecasts for each theme (1-3) contain separate Utility Solar, Customer Solar, On-Shore Wind, and Off-shore Wind Capacity assumptions. Load forecasts are constant between themes.

Maui

Load	HELCO System Load was used as a proxy for MECO System Load in April, August, and De 2014.
Utility PV	HECO PV data was used as a proxy for MECO Solar
Customer PV	HECO PV data was used as a proxy for MECO Solar
On-Shore Wind	HECO Wind Data was used as a proxy for MECO wind

The overlapping time intervals for the above historical data was used for this analysis. Overlapping data existed for 3 months in April, August, and December 2014. Annual forecasts for each theme (1-3) contain separate Utility Solar, Customer Solar, On-Shore Wind, and Off-shore Wind Capacity assumptions. Load forecasts are constant between themes.

BLACK & VEATCH: DEMAND RESPONSE EVALUATION

Black & Veatch used its Adaptive Planning for Production Simulation (AP) model to evaluate Demand Response for the purpose of including Demand Response in the plans evaluated in support of the December 2016 update to the PSIP. The methodology, the AP model, and the plans incorporating DR are described elsewhere in this update. The following description focuses on the DR portfolio recommended for each island and the inputs that have a significant bearing on the recommendation.

The December 2016 update to the PSIP contains numerous plans. The DR evaluation was conducted using the post-April 2016 PSIP plan for each island, and the results were used in the production simulation and capacity planning models for the December 2016 PSIP update evaluation period. Grid service valuation was initially performed on a single plan per island; this guided the evaluation of DR amounts, costs, and the impact on system load shapes. Those initial plans per island were:

- *O'ahu, Hawai'i Island, and Maui:* Renewables without LNG
- *Lana'i and Moloka'i:* 100% renewable energy achieved in 2030

DR amounts, costs, and the impact to system load shapes were then evaluated on all post-April PSIP plans. In addition to those listed above, this included:

O'ahu and Maui:

- Accelerated renewables without LNG
- Renewables without LNG and without new generation
- Renewables with LNG

Hawai'i Island:

- Accelerated renewables without LNG
- Renewables with LNG

Later analyses involving both grid services valuing as well as defining DR amounts, costs, and the impact to system load shape were performed on the E3 plan:

- *O'ahu:* E3 Plan with generation modernization. The E3 Plan was preliminarily examined, but due to concerns (identified in the Upcoming Capacity Need section below) was not fully evaluated.
- *Hawai'i Island and Maui:* E3 Plan

Results of grid services valuing, updated for any differences developed following the post-April PSIP plan evaluations, will be documented in the February 2017 DR Application.

DR portfolios were provided to the PSIP modeling teams in the form of spreadsheets with sufficient detail to allow full, 8,760 hour/year incorporation of DR. The DR portfolio spreadsheets were specific to each island and each plan evaluated. Each spreadsheet contained the following tabs:

Buildout Modification: This tab represents the grid-scale assets that can be avoided or deferred based on the addition of DR resources. When evaluating the removal of firm generation on O'ahu, additional Loss of Load Probability modeling is undertaken to confirm that the system still meets acceptable system reliability metrics.

Spin: The spin tab represents the amount of spin equivalent that DR regulating reserve assets are capable of providing in each hour of the study period, following allocation to FFR and load shift. Customer batteries are a critical contributor to DR's ability to provide regulating reserves. The current assumption for regulating reserves from customer batteries is that batteries are able to provided regulating reserve up based on the amount of charging currently occurring (i.e., the charge can be interrupted).

Load Modification Profile: This tab represents the incremental change to demand resulting from DR assets for each hour of the study period. These DR assets seek to reduce peak loads, utilize curtailment and in general allow firm generating units to operate at more economic heat rates.

Modified Demand Profile: The Modified Demand Profile tab represents the modified gross demand after the effects outlined in the Load Modification Profile are taken into account. This profile also details every hour of the study. This tab provides an easy plug and play input to other models that are already incorporating an unmodified gross load profile.

In addition to evaluating DR, Black & Veatch performed Loss of Load Probability (LOLP) modeling for certain O'ahu cases to help confirm the adequacy of supply associated with those cases.

Demand Response Plan – O‘ahu

The current plan for O‘ahu’s demand response portfolio is to reduce the size of the contingency battery via FFR DR, load shift via pricing programs and provide regulating reserves.

System Characteristics – O‘ahu

Current Generation

Baseload Generation

- 6 Steam Units at Kahe (650 MW total)
- 2 Steam Units at Waiau (83 MW and 86 MW for Waiau 7 and 8 respectively)
- 1 Combined Cycle Unit (208 MW)
- 1 Coal Unit (189 MW)
- 1 Waste Fired Unit (68.5 MW)

Intermediate Generation

- 4 Steam Units at Waiau (200 MW for Waiau units 3 through 6)

Peaking Generation

- 2 Combustion Turbines at Waiau (103 MW)
- 1 Dual Fuel Fired Combustion Turbine (130 MW on diesel and 115 on biodiesel)

Renewable Generation

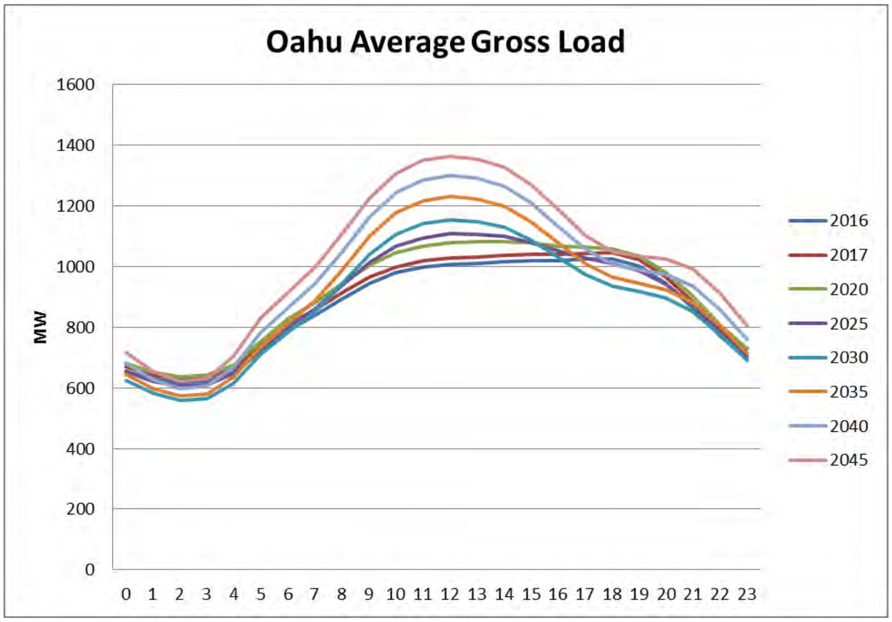
- 3 Wind Farms-Kahuku, Kawailoa Wind and Na Pua Makani (30 MW, 69 MW and 24 MW respectively)
- 3 Solar Farms-KSEP, KREP and Kalaeloa Solar 2 (5 MW, 5 MW and 1 MW respectively)

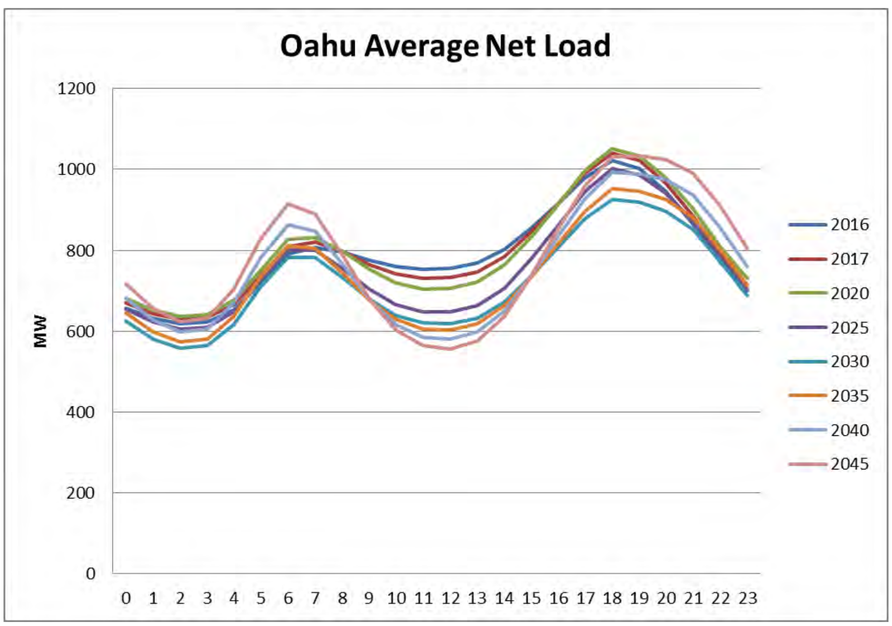
Distributed Generation

- DG-PV- roughly 400 MW currently

Load Profile Characteristics

The system is generally an evening peak system with a smaller morning bump in load on a net basis. There is a significant change in the effective shape of the load over time that has resulted in an increasing midday load without a significant change to the rest of the day.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Upcoming Capacity Need

The island of O'ahu has over 1700 MW of firm generation currently online for a system that currently has an annual peak load of roughly 1170 MW. As a result, the island currently has a reserve margin of around 45%. While the system does have excess capacity currently, the speed of the system is lacking. Only two units can turn on in less than 40 minutes. The baseload generation on the island is both slow and relatively inefficient compared to new technologies. The current plan is to retire Waiau units 3 through 6 in all plans (except the E3 Plan, addressed below). These units will be effectively replaced with various ICE units installed at military bases. These new units will provide speed to the system as well as additional reliability to the system as a whole and to the bases where they are located. Plans also include the future retirements of all Kahe units with the intent of replacing the units with more efficient and fuel flexible one on one combined cycle units.

The E3 Plan, as currently defined, may have difficulty meeting the capacity needs of O'ahu. The E3 Plan calls for the retirements of AES, Waiau 3, Waiau 4, Waiau 5, Waiau 6, Waiau 7, Waiau 8, Kahe 1, Kahe 2, Kahe 3, and Kahe 4 by 2022 with only 426 MW of load shifting battery added to the system. With nearly 900 MW of firm capacity retired, even with customer batteries and load shifting DR, production simulation and LOLP modeling indicate that the system will likely suffer significant unserved demand. Due to the capacity concerns associated with the E3 Plan as currently defined, we have deferred evaluation of DR for this plan until such time as the plan can be re-constructed to more closely meet capacity needs.

High Solar Penetration

The electric system on O'ahu has limited on-shore wind potential and significant solar potential. With off-shore wind being expensive and given the aggressive renewable targets set by the state, solar will be the primary source of renewable generation on the island. There is already a significant amount of rooftop solar on the island and all of the plans will add additional grid-scale PV projects to the island. The E3 Plan with generation modernization adds nearly 1800 MW of grid-scale solar while the Renewables without LNG plan will add 840 MW. In the near-term, both plans will install nearly 140 MW of grid-scale solar via the Waiver PV solar farms.

Off-Shore Wind Penetration

As the electric system on O'ahu is saturated with solar energy, the need for nighttime renewable generation will drive the installation of significant off-shore wind assets. While off-shore wind has high capital costs, the wind quality is much higher than on-shore assets making it the more attractive choice. All plans install off-shore wind assets. The E3 Plan with generation modernization targets an installation of 200 MW in 2025. The Renewables without LNG plan includes two 400 MW installations in 2040 and 2045, respectively.

Load Shifting Battery

With the staggering amount of solar energy being installed on the island, the need for load shifting batteries is critical. Load shifting batteries will both reduce curtailment of free energy and reduce fuel usage. 300 MW of load shifting batteries are scheduled to be installed in 2030 for the Renewables without LNG plan. The E3 Plan with generation modernization targets installation of 2700 MW through 2045. These batteries could represent a potential opportunity for deferment via DR as they provide the same services. Both the Companies and E3 teams incorporated the load shifting capabilities of DR into their buildout plans. Thus, the sizing of the load shifting batteries accounts for the load shift ability provided by DR.

Regulating Battery

The Renewables without LNG plan for O'ahu installs a 100 MW regulating battery in 2020. The E3 Plan with generation modernization does not include a regulating battery. This battery would provide significant value to the grid providing quick ramping as well as regulation. Regulation from a battery instead of online generation can provide significant fuel savings. This battery is probably not a candidate for deferral via DR as it provides regulation at all hours of the day and is relatively less expensive than other potential deferral options.

Contingency Battery

Absent of DR, O'ahu plans install a 120MW contingency battery in 2019. Following the expected retirement of AES, this battery will bring the system into TPL-001 compliance meaning the system should no longer rely on load shedding to restore system stability following a contingency event. While the battery is targeting installation in 2019, the retirement of AES is not expected until 2022. This means a full trip of AES in the middle of the day could still result in the need to load shed to restore the system.

The O'ahu system's need for FFR peaks during the middle of the solar day for two main reasons. The first reason is that significant solar generation allows for the de-commitment of firm units to minimize curtailment. A side implication to de-committing units is that the kinetic energy of the system will be at its lowest during this period of the day. At the same time, the contingency need is exacerbated during the middle of the day due to 55 MW of legacy inverters connected to DG-PV. These inverters will trip if the system frequency drops below 59.3 Hz. Because the need for FFR peaks in the middle of the day, the battery is effectively oversized in non-solar hours. This represents an opportunity for demand response to downsize the contingency battery by providing mid-day FFR.

DG-PV Growth

DG-PV is expected to grow to about 1400 MW over the next thirty years based on the latest market forecast. The High DG-PV forecast sees over 2,100 MW of DG-PV possibly being added to the system. Regardless of the forecast being examined there will be significant curtailment of renewables in the future on the island without Demand Response programs and significant load shifting batteries.

Customer Battery

Customer battery populations grow rather dramatically towards the end of the study reaching about 180 MW by 2030 and 580 MW by 2045.

Demand Response Potential

Demand response potential for FFR is 30 MW in 2019 allowing the downsizing of the contingency battery. Pricing program potential for non-battery demand response end devices grows quickly from about 40 MW in 2019 to 90 MW in 2030. Potential for regulating reserves is about 15 MW.

Demand Response Implications – O‘ahu

There are a few natural candidates for deferral on the island in particular a portion of the load shifting and contingency batteries. Load shifting in combination with FFR looks to be a promising, complementary opportunity for DR as the need for FFR load reduction will occur in the middle of the day while the need for load shift load reduction will occur on the evening peak. Because of the high amount of solar energy there is a natural benefit for DR to provide load shifting into the solar peak and away from the evening peak load. With the emphasis on load shift and FFR, there is still potential for regulating reserve to be provided by end devices not providing FFR during the middle of the day.

Demand Response Plan – Hawai'i Island

The current plan for the demand response portfolio on Hawai'i Island is to obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Hawai'i Island

Current Generation

Must-Run Generation

- 1 Combined Cycle Unit- Keahole (53.5 MW)
- 3 Steam Units - Hill 5, Hill 6 and Puna Steam (13.5 MW, 20 MW, and 15.5 MW respectively)
- Geothermal – PVG (30 MW must take on peak, 27 MW must take off-peak, 38 MW dispatchable)

Intermediate Generation

- 1 Combined Cycle - HEP (60 MW)
- 1 Simple Cycle Gas Turbine- Puna CT3 (19MW)

Peaking Generation

- 2 Simple Cycle Gas Turbines - Kanoelehua CT1 and Keahole CT2 (10MW and 14 MW respectively)
- 14 Small Diesel Generators (28 MW total)

Renewable Generation

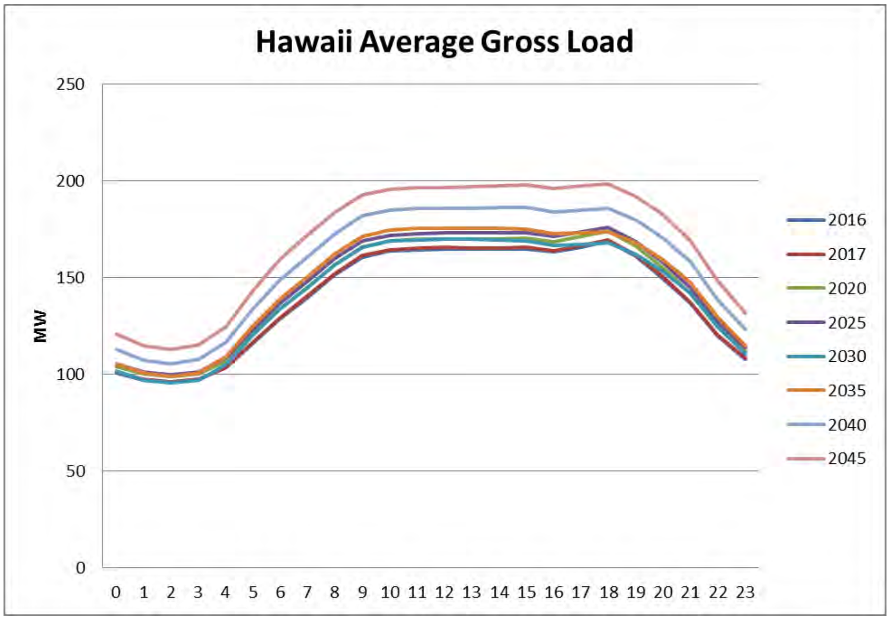
- 2 Wind Farms - Tawhiri and HRD (20.5 MW and 10.5 MW respectively)
- 1 River of River Hydro Unit - Wailuku (12.1 MW)

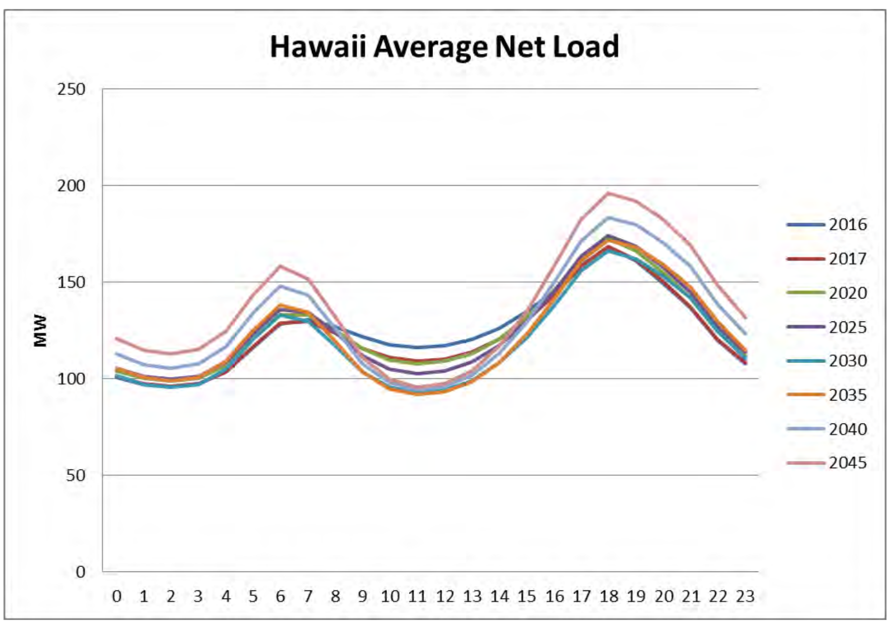
Distributed Generation

- DG-PV - 85–90 MW currently

Load Profile Characteristics

The system is an evening peak system with a smaller morning bump in load on a net basis. There is no significant change in the effective shape of the load over time but there is a general increase in energy demand over time.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Lack of Capacity Need

The island of Hawai'i has over 270 MW of firm generation for a system that currently has an annual peak load of roughly 190 MW. As a result, the island has excess capacity and a reserve margin of well over 40%. Current plans do not include any new units added strictly for capacity, although new firm renewable units help meet capacity while ensuring grid stability in the non-E3 plans. The E3 Plan on Hawai'i may be short on capacity in the near-term following the retirement of Hill 5, Hill 6 and Puna Steam in 2020. Because utilization of demand response programs does not avoid new generation, the savings found by DR will be operational.

High Wind Penetration

While the system has about 31 MW of onshore wind currently, most plans will increase that number significantly. The Renewables without LNG plan is scheduled to add 20 MW in 2020 and an additional 20 MW in 2030. The E3 Plan will add 100 MW of wind to the system with 70 MW installed by 2022. Both existing wind farms have relatively unfavorable contracts from the perspective of incentivizing a reduction in their curtailment. The energy provided is charged at the relatively high avoided cost rate and there is currently no cost to curtail energy that cannot make its way on to the system. These contracts are set to expire in 2021 for HRD and 2027 for Tawhiri.

Current and Future Geothermal

Currently, the island of Hawai'i gets about 20% of its energy from the geothermal plant, PVG. The Renewables without LNG plan includes an additional 40 MW of geothermal energy on the island by 2030. These new geothermal units will have very low variable costs and reasonable ability to turn down in response to heavy wind and solar production. The E3 Plan does not include additional geothermal generation.

Retiring Must Run Units

In the Renewables without LNG plan new geothermal units and a new 20 MW Biomass unit will come online as must run units and replace the aging must-run steam units. This switch in must-run units maintains the system security as renewable penetration increases while still replacing oil burning generation with firm renewable units. The E3 Plan retires Puna Steam, Hill 5, and Hill 6 all in 2020 but without replacing them with other firm generation.

Contingency Battery

Although a 15 MW contingency battery installation is planned in 2019, using FFR DR to downsize this battery will not result in the most cost effective DR portfolio. On O‘ahu there is a much greater FFR need in the middle of the day due to the 55 MW legacy DG-PV that will trip with a major system disturbance. On Hawai’i Island this is not the case as the need for FFR is much more constant throughout the day. Therefore if some portion of the contingency battery was deferred by FFR DR then the system would need to reserve those end devices throughout the day, including during the evening peak hours. Because these end devices would be reserved for FFR load reduction services during the evening peak, they could not be used to reduce load as part of a load shifting scheme. The decision then becomes a tradeoff between the more attractive economic choice - load shifting - versus contingency battery reduction.

In addition to the economic considerations for choosing load shifting DR over FFR for Hawai‘i Island, there are also significant security concerns with utilizing DR FFR on Hawai‘i Island. Unlike O‘ahu, Hawai‘i Island may still utilize under frequency load shedding to maintain system security in response to large system disturbances. Because DR FRR MWs will be on the same circuits that could be subject to load shedding this may materially affect how much load exists on each kicker block. FFR DR can introduce uncertainty as to the amount of load shed available which could in turn make a relatively small system disturbance larger.

DG-PV Growth

DG-PV is expected to grow to about 150 MW over the next thirty years based on market forecast used in the April 2016 update to the PSIP. The High DG-PV forecast sees over 460 MW of DG-PV added to the system. Regardless of the size of the forecast there will be significant curtailment of renewables in the future without Demand Response programs or significant load shifting batteries.

Customer Battery Installations

Customer battery populations grow rather dramatically towards the end of the study reaching about 20 MW by 2030 and 60 MW by 2045.

Demand Response Potential

Pricing program potential for non-battery demand response end devices grows from about 4 MW in 2019 to 8 MW in 2030. Potential for regulating reserves is about 8 MW.

Demand Response Implications – Hawai‘i Island

Hawai‘i Island has a difficult resource mix to facilitate a cost effective demand response program, especially in the near term. With no assets added strictly for capacity, TOU and Real Time Pricing programs will have to be cost effective based strictly on operational savings. With the structure of the PPA agreements with the current wind farms and hydro plant, uncurtailing renewables can increase the percentage of renewables on the system but not result in cost savings. As those contracts expire and new contracts are negotiated this can change quickly. Current modeling assumptions switch to NREL fixed and variable cost pricing after the current contracts end. NREL pricing structures incentivize increased renewable utilization through high fixed costs and minimal to zero variable cost. Because Hawai‘i Island's current requirements are not dedicated to the TLP-001 standard that O‘ahu is planning to attain, it is hard to prove an avoided cost savings for an FFR DR program. When PPA contracts expire and biodiesel fuel switch occurs DR will find significant value in load shifting and regulating reserve programs based on a reduction in fuel usage and subsequent fuel cost savings.

Demand Response Plan – Maui

In the near term, demand response appears to be an effective means to assist in meeting capacity need. In addition, Maui's demand response portfolio will obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Maui

Current Generation

Baseload Generation

- 4 Oil Fired Units at Kahului (32.5 MW total)
- 1 Combined Cycle Ma‘alaea DTCC1 (53 MW)

Intermediate Generation

- 8 Oil Fired Units at Ma‘alaea (71 MW total)
- 1 Combined Cycle Ma‘alaea DTCC2 (53 MW)

Peaking Generation

- 7 Oil Fired Units at Ma‘alaea (23.5 MW total)

Renewable Generation

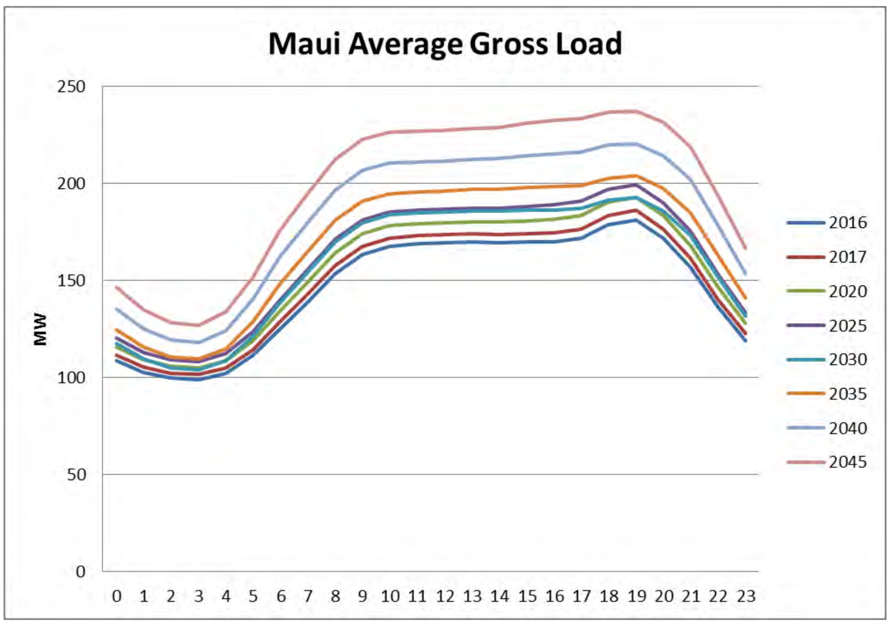
- 3 Wind Farms - Auwahi Wind Energy, Kaheawa Wind Power and Kaheawa Wind Power 2 (21 MW, 30 MW and 21 MW respectively)
- 1 River of River Hydro Unit - Makila Hydro (0.5 MW)
- 1 Solar Plant - South Maui Renewable Resource (5.47 MW starting 2017)

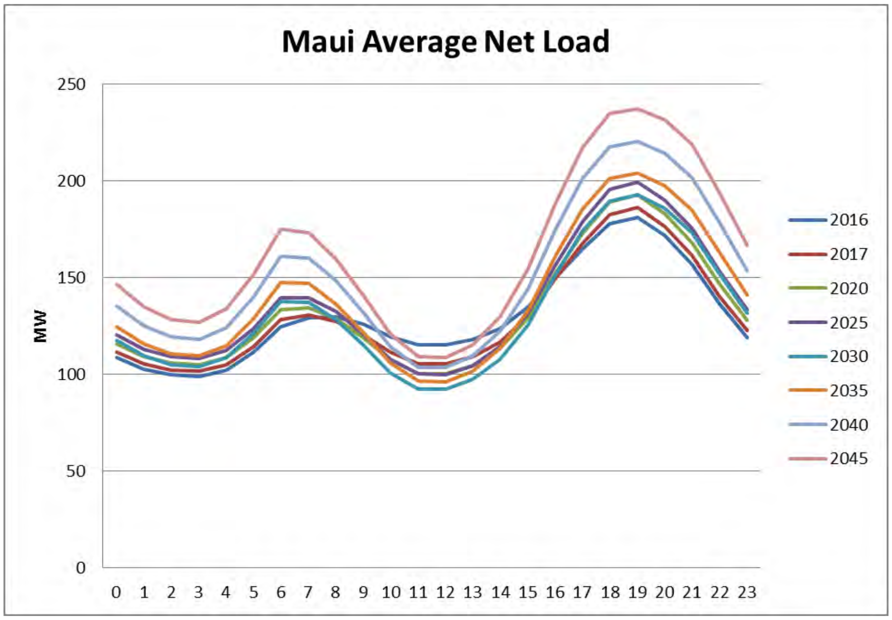
Distributed Generation

- DG-PV - 90 MW currently

Load Profile Characteristics

The system is an evening peak system with a smaller morning bump in load on a net basis. There is no significant change in the effective shape of the load over time but there is a general increase in energy demand over time.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Upcoming Capacity Need

The island of Maui has over 237 MW of firm generation online for a system that currently has an annual peak load of roughly 200 MW. As a result, the island has a reserve margin of around 18%. Maui's limited capacity is at least partially due to the pending retirement of the HC&S bagasse burning unit in addition to growing electrical demand. As a result, two units, Kahului 1 and Kahului 2, have recently been reactivated. Following the planned retirement of all four Kahului units in 2023, the system will again have a need for capacity. The current plans include the installation of firm biomass and geothermal, load shifting storage, and new ICE units. Because the island of Maui does have a capacity need it is likely that DR will be able to find some capital savings from the downsizing or deferral of new assets.

The E3 case on Maui may be short on capacity in the 2045 following the retirement of Maʻalaea units 4 through 13.

High Wind Penetration

The electric system on Maui has 72 MW of wind currently with aggressive plans to expand further. The Renewables without LNG plan includes the installation an additional 90 MW of wind in 2020. The E3 Plan includes 60 MW of new wind in 2020. With over 110 MW of wind on the island in 2020 in all themes, the transition to real time pricing will be critical to unlock the full benefits of load shifting. Unlike solar assets which only generate energy during the middle of the day, wind energy can be generated all day. This potential to generate at any time of the day will require a more dynamic pricing program to enable more wind energy to make it on the grid. However, a more dynamic pricing program will only be as effective as the ability to forecast wind generation in the future. Our model currently functions with perfect knowledge of future wind variability and might understate the uncertainty related to forecasting wind generation.

Current and Future Geothermal

Currently, there are no geothermal assets on the island of Maui. All plans install 40 MW of geothermal units. The Renewables without LNG plan targets installing 40 MW in 2030 while the E3 Plan targets an installation date of 2040. These new geothermal units will have very low variable costs and reasonable ability to turn down in response to heavy wind and solar production.

Current and Future Biomass

There is just one biomass plant on Maui, HC&S, and that plant is scheduled to retire in 2017. The Renewables without LNG plan includes the installation of 20 MW of biomass in 2022 and an additional 40 MW in 2040. The E3 Plan installs 40 MW of biomass in 2022. These units will be baseload and provide some turndown to allow non-firm renewables to make it on to the system.

Retiring Must Run Units

All Kahului units are scheduled to retire in either 2022 or 2023. Firm renewables will replace these units starting with the biomass unit being installed in 2022 and continuing with the other biomass and geothermal installations.

DG-PV Growth

DG-PV is expected to grow to about 200 MW over the next thirty years based on market forecast used in the April 2016 update to the PSIP. The High DG-PV forecast sees over 435 MW of DG-PV being added to the system. Regardless of the forecast being examined there will be significant curtailment of renewables in the future on the islands without DR or significant load shifting batteries.

Customer Battery Installations

Customer battery populations grow stead towards the throughout the study reaching about 30 MW by 2030 and 68 MW by 2045.

Demand Response Potential

Pricing program potential for non-battery demand response end devices grows quickly from about 6 MW in 2019 to 16 MW in 2030. Potential for regulating reserves is about 20 MW.

Demand Response Implications – Maui

Maui is very similar to Hawai‘i Island in terms of the DR portfolio with some notable exceptions. While Hawai'i has PPA agreements that make reducing wind curtailment less economical in the immediate term, Maui does not have those same contract structures. The dynamic nature of real time pricing will be necessary to capture the potential wind resources on Maui. With significant renewable resources come increased regulating requirements, so regulating reserves provided by DR should contribute high value to the island. Because Maui is not targeting, at this time, to meet the TLP-001 standard that O'ahu is pursuing, it is hard to prove an avoided cost savings for an FFR program. During Maui's capacity need it is likely that DR will serve to displace a load shifting battery or other asset by providing the same services. Even absent capital avoidance, DR is expected to provide significant value in load shifting and regulating reserve programs from a reduction in fuel usage.

Demand Response Plan – Lana‘i

The current plan for the demand response portfolio on Lana‘i is to obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Lana‘i

Current Generation

Baseload Generation

- 2 ICE Units (4.4 MW total)

Intermediate /Peaking Generation

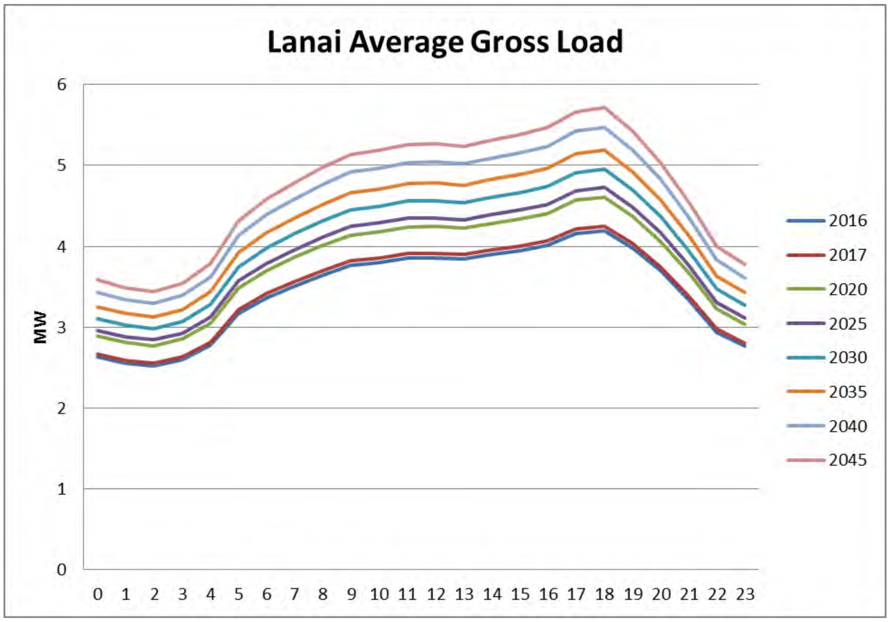
- 6 ICE Units (6 MW total)
- 1 CHP (0.83 MW)

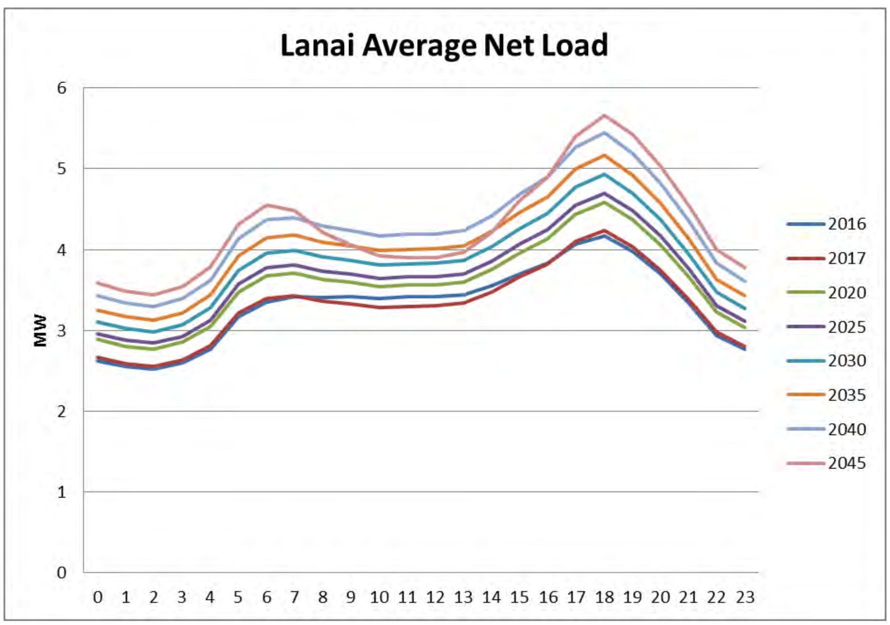
Distributed Generation

- DG-PV - roughly 0.8 MW currently

Load Profile Characteristics

The system is generally an evening peak system with a smaller morning bump in load on a net basis.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Lack of Capacity Need

The island of Lana'i has about 11.2 MW of firm generation compared to a current peak load about 5.2 MW. Plans for the island do not contain new firm unit installations.

Solar Penetration

Lana‘i has significant solar potential that far exceeds the need of island. However, plans do not include grid-scale solar and instead focus on grid-scale wind.

Wind Penetration

Lana‘i has significant wind potential. All plans for the island include at least 4 MW of wind installed in 2020.

DG-PV Growth

DG-PV is expected to grow to about 2.2 MW over the next thirty years based on the latest market forecast. There will be curtailment of renewables in the future on the island without DR, particularly once the wind generation is added to the island in 2020.

Customer Battery Installations

Customer battery populations grow slowly throughout the study reaching about 0.17 MW by 2030 and 0.7 MW by 2045.

Demand Response Potential

Pricing program potential for non-battery demand response end devices grows from about 0.05 MW in 2019 to 0.1 MW in 2030. Potential for regulating reserves is about 0.04 MW.

Demand Response Implications – Lana‘i

With high renewable penetration targeted on the island, DR will find value in load shifting to take advantage of curtailed energy. Because the island is operated primarily with 8 ICE units there is minimal operational savings associated with load shifting that does not capture curtailment. The high renewable penetration creates a need for regulating reserves that can reduce curtailment by de-committing units online to serve regulation.

Demand Response Plan – Moloka‘i

The current plan for Moloka‘i’s demand response portfolio is to obtain operational savings through load shifting via pricing programs and by providing regulating reserves.

System Characteristics – Molokaʻi

Current Generation

Baseload Generation

- 3 ICE Units (6.6MW total)

Intermediate /Peaking Generation

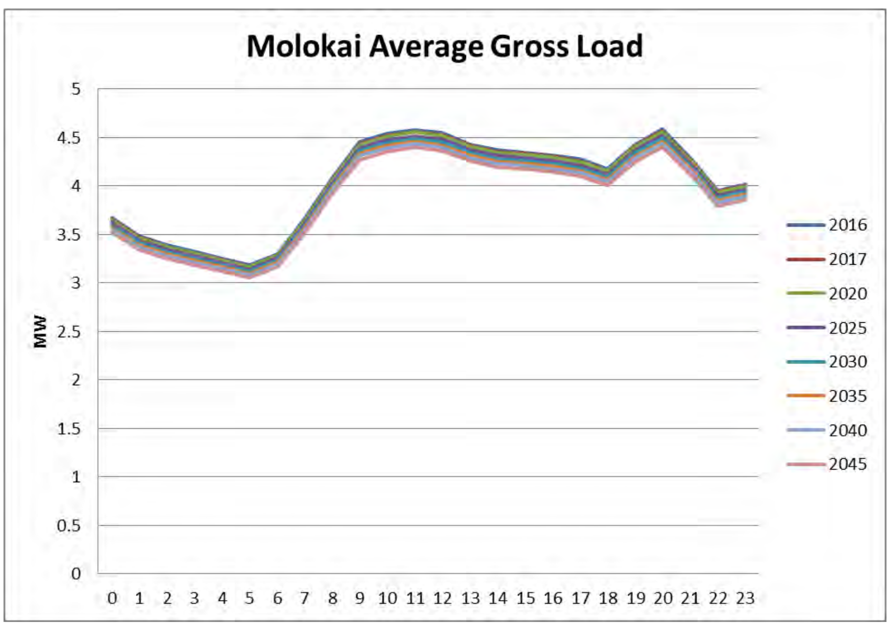
- 6 ICE Units (6.4MW total)
- 1 Combustion Turbine (2.2 MW)

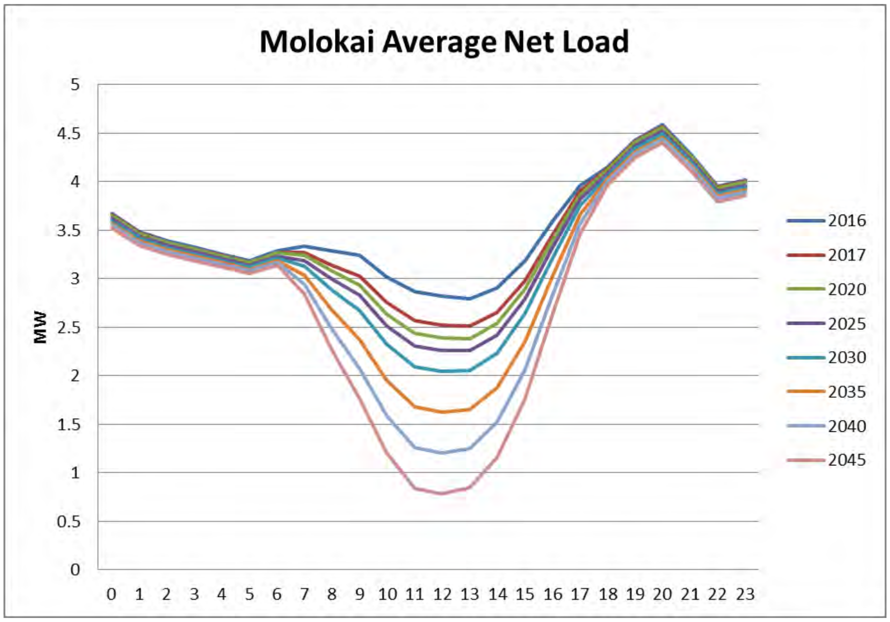
Distributed Generation

- DG-PV- roughly 2.5 MW currently

Load Profile Characteristics

The system is generally an evening peak system with a smaller morning bump in load on a net basis.





Note: Above graphs are based on April 2016 updated PSIP with Market DG-PV adoption.

Lack of Capacity Need

The island of Moloka'i has about 15 MW of firm generation compared to a peak load about 5.5 MW. There is likely no need for additional firm generation and plans for the island do not contain new firm unit installations.

Solar Penetration

Moloka'i has significant solar potential that far exceeds the need of island. However, plans do not include grid-scale solar and instead focus on grid-scale wind.

Wind Penetration

Moloka'i has significant wind potential. All plans for the island include at least 4 MW of wind installed in 2020.

DG-PV Growth

DG-PV is expected to grow to about 5.5 MW over the next thirty years based on the latest market forecast. There will be significant curtailment of renewables in the future on the island without DR especially following the wind installation in 2020.

Customer Battery Installations

Customer battery populations grow rather dramatically towards the end of the study reaching about 1.3 MW by 2030 and 5 MW by 2045.

Demand Response Implications – Moloka'i

With high renewable penetration targeted on the islands, DR will find value in load shifting to take advantage of curtailed energy. Because the island is operated primarily with 9 ICE units there is minimal operational savings associated with load shifting that does not capture curtailment. High renewable penetration on the island creates a need for regulating reserves which can reduce curtailment by de-committing units online to serve regulation.

Q. Customer Exit Economic Analysis

Pages Q-2 through Q-4 contain confidential and/or proprietary information, and are designated as "restricted information" to be provided only to the Commission and the Consumer Advocate, and not to be distributed to any other party or participant to this proceeding or its representatives.