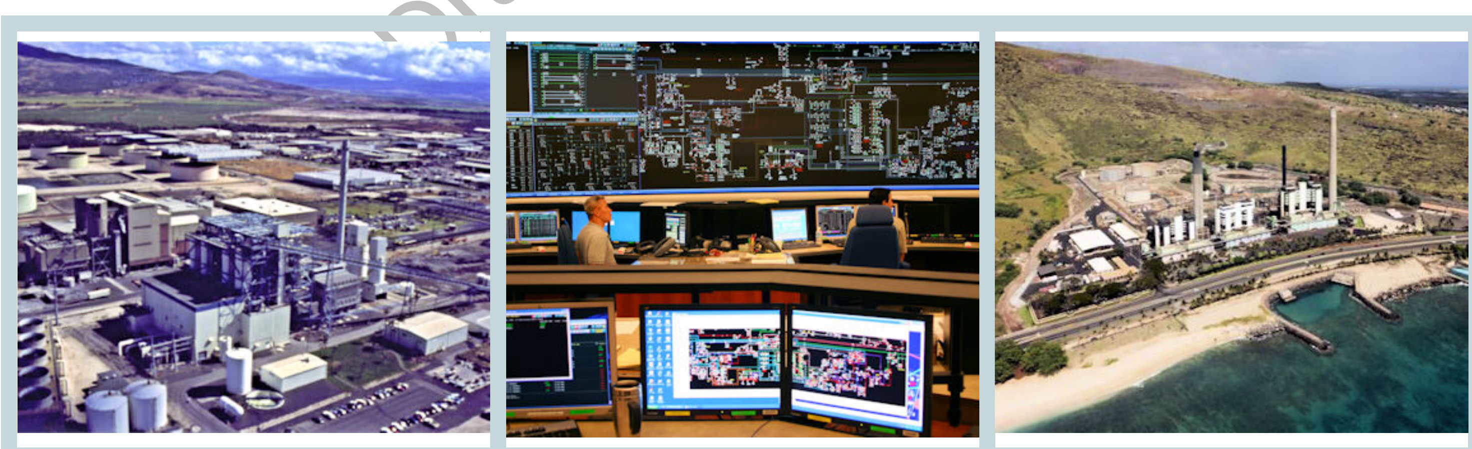
O‘ahu Outage

Kahe 5 and AES Trip Events

An analysis of the two trip events and the resultant outages on 12–13 January 2015 together with potential mitigation measures to effectively handle future generation shortfalls

October 2015



Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

Preface

This report was the brainchild of Alan. He sees it as an opportunity to go on record about the changing resiliency of the grid with all the renewables, what Hawaiian Electric is doing about it, and what customers can expect in the future.

[Preface text]

Table of Contents

FIGURES

TABLES

Executive Summary

The evening rolling outages on January 12, 2015 constituted the first such outage in over six years, since December 26, 2008. As such, the current outage fell well within our reliability guidelines of one day every 4½ years.

OVERVIEW OF THE DAY'S EVENTS

Through a combination of forced outages, derates, and a planned outage, the day began with low unit availability. Then, early in the morning, Kahe 5 unexpectedly tripped offline. In early afternoon, an AES boiler tripped offline, leading to a ramp down over a period of nine minutes when the loss of the second boiler caused the AES turbine to trip. AES fully tripping offline caused distributed generation photovoltaic (DG-PV) output to also trip offline. In addition, wind generation was negligible. These events led to a brief (two to six minutes) afternoon outage. The outage affected about 20,325 customers.

During the afternoon, we issued a call for energy conservation which helped reduce demand. In addition, we dispatched the Residential Direct Load Control (RDLC) demand response program, also reducing demand.

As evening began, all PV generation ceased; wind generation remained between 0.2 MW to 3.6 MW (out of 99 MW). The AES trip event meant that only 947 MW of generation (about 56.2% of a total firm capacity of 1,684 MW) was available to meet an evening peak load projected to be over 1,030 MW. With this reduced capacity, we were forced to institute two sets of rolling outages that lasted a total of one hour and 23 minutes, and affected about 28,840 customers (different from the customers affected by the afternoon outage).

Unfortunately, the rolling outages coincided with part of the college BCS Championship football game featuring Marcus Mariota, a Honolulu-born Samoan and local fan favorite, which exacerbated customer reaction.

INCREASING AMOUNTS OF DG-PV COMPROMISES GRID RESILIENCY

Increasing amounts of renewable energy, especially DG-PV which comprises the vast majority of PV generation, compromises grid resiliency. DG-PV has eroded the capability of the grid to survive multiple contingencies—such as the afternoon outage and evening rolling outages on O'ahu on January 12, 2015.

The Unreliability of Variable Generation to Meet Peak Demand

As the evening peak demand period approaches, the generation from DG-PV diminishes and then stops. While wind generation can be available all day and night, in general, wind's largest capacity is at night.

Generation from both resources, however, is unreliable; it changes from day to day with no pattern for accurate prediction. As such, we cannot rely on this variable generation to provide the spinning reserve necessary to reliably meet demand. We can only rely on firm generation.

In addition, the IEEE 1547 settings cause DG-PV to automatically trip offline whenever system frequency drops to 59.3 Hz, further magnifying a contingency.

The Variability of Variable DG-PV

We can only estimate the amount of DG-PV on the system at any point in time. Some days DG-PV generation is high, reducing daytime load to minimal amounts. Other days, DG-PV generation is low, keeping daytime load to historical levels.

Weather, of course, is the major factor affecting DG-PV generation. Constantly sunny days keep DG-PV generation high; days with large amounts of cloud cover or constant rain keep DG-PV generation low. These type of weather days are the outliers. More frequently, cloud patterns and rain squalls move across O'ahu lowering generation in one area while generation remains high in other areas.

These type of weather patterns make for a roller coaster ride for generation. As a result, maintaining system frequency within a small window becomes challenging—a challenge that will only exacerbate as the proliferation of DG-PV continues.

Current Conditions Happening Much Sooner than Projected

Historical data show the average daily demand curve slowly increasing throughout the day, peaking during the evening, then dropping back down overnight. In 2011, we began to notice significant changes in this pattern. In 2013, we projected the average daily load curves for the next five years.

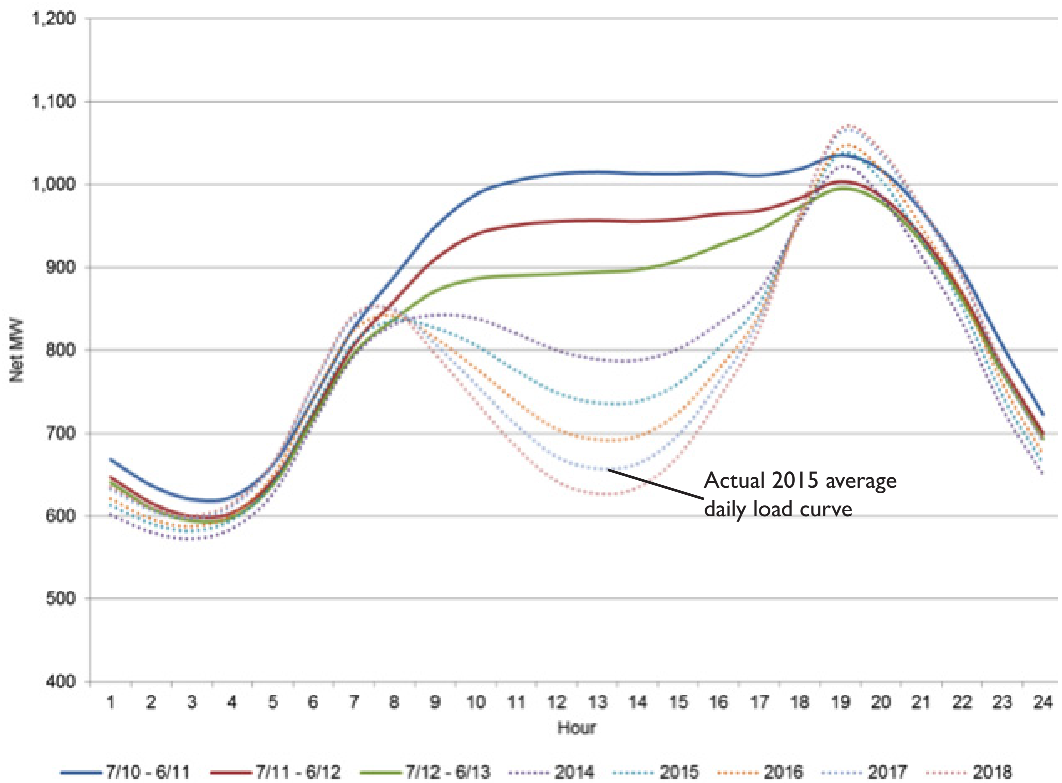


Figure 1. Evolving Demand Profile from DG-PV Growth

Two years ago, we projected the average daily load curve to look like the dotted blue line (labeled "2015"). Because of the rapid increase in DG-PV, the actual average daily load curve is more accurately represented by the dotted light blue line (labeled "2017")—a full two years ahead of projections.

An average daily load curve that keeps dropping during the late morning and afternoon dramatically affects how we manage grid stability and respond to fluctuations in demand.

Grid Management Challenged by Increasing Amounts of DG-PV

DG-PV generation cannot be predicted, cannot be curtailed, and amounts cannot be know. Our system operators manage the grid as best as possible despite these conditions. Their results have been exemplary despite the mounting challenges.

Carrying Extra Spinning Reserve. Increasing amounts of DG-PV entering the system cause daytime demand to continue to erode on high DG-PV penetration days. On these days (which as we know cannot be predicted or accurately known), the amount of spinning reserve necessary is reduced.

System operators can only estimate the amount of DG-PV running on the power grid. One method of countering this situation is to carry more spinning reserve. When DG-PV generation is high, this additional spinning reserve unnecessarily increases costs. Keeping spinning reserve levels low, however, increases the possibility of not having enough generation to meet demand.

Daily Unpredictability of Load. High DG-PV days reduces daytime system load. When our largest unit (usually AES) trips at full capacity, contingency reserves (such as governor droop and demand response) are insufficient to arrest the drop in system frequency. The only solution is to employ UFLS to stabilize the system. This, of course, leads to outages. During the January 12, 2015 trip event, the AES ramp down gave us some time to commit Waiau 10, so only one UFLS block was shed, thus containing the outage.

Unit Modifications to Better Manage Grid Reliability

We are making modifications to our utility-owned firm generation units to better respond to the evolving system conditions. None of our units, however, were designed for these modifications. These units were designed to operate in a range of 45%–95% of their rated capacity. Our modifications are enabling us to operate them in a range of 8%–95%. These are complicated processes that we have fully trained our operators to effectively handle.

Enhanced Low-Load Operation. By pulling burners from the unit boilers, we are able to run these units at levels as low as 7 MW. The pressure on the unit lowers are we reduce the load on the unit. Thus, the unit's ability to respond to system disturbances is equally as limited.

Cycling. Another method of handling low demand is to simply turn off one or more firm generation unit—cycle the units. Turning off units decreases the amount of inertia on the system, making the power grid more vulnerable and thus less reliable. In addition, these units ramp slowly on startup (up to 4½ hours), so their ability to respond to generation shortfalls is limited. Finally, turning on these units to meet evening peak is fraught with problems: a unit might take longer than expected to startup, or fail during its startup, both of which increase the probability of a generation shortfall during evening peak.

Ramp Rates. Designed ramp rates for our units run at about 3 MW per minute. We are currently pushing ramp rates to 5 MW per minute. To accomplish this, we must run the unit at full pressure. These increased ramp rates, however, decrease the unit's overall stability.

Increased Unit Maintenance Reduces Availability

All of the modification outlined in "Unit Modifications to Better Manage Grid Reliability" (the previous section) come at a cost: they reduce the reliability and stability of the units. As a result, they tend to experience more problems which can exacerbate generation shortfalls. In addition, they increase the need for routine, planned maintenance, which results in decreased availability.

There is also a possibility that we could get into a routine of washing the machines in order to keep their output at their highest levels. This puts additional pressure on staff to maintain this process while keeping output at top levels. This only serves to aggravate future maintenance plans that for already call for significantly more outages to comply with MATS requirements.

UFLS Settings

This current trip event required one block of UFLS to stabilize system frequency, even though sufficient amounts of spinning reserve was on the system. This is mainly because our UFLS scheme cannot account for DG-PV tripping offline, so the contingency does not look as large as it actually is. (Specifically, the UFLS scheme only considered the final AES loss of 70 MW as the contingency, and not the 9 MW net generation output of AES auxiliary loads nor the approximate 25 MW of Legacy PV that disconnected from the system at 59.3 Hz.)

As a result, this larger contingency caused a higher rate of change of frequency, making traditional governor droop response ineffective in arresting system frequency.

Lower System Inertia

System inertia is lower because DG-PV has displaced synchronous generation. Our largest units, of course, provide the highest levels of system inertia, so when they trip offline, the resultant reduction in inertia is greater. In the past, we would have committed units to meet a three-second Quick Load Pick Up (QLPU) criteria, however, increasing amount of DG-PV coupled with other factors has made the QLPU criteria no longer in use. The obsolete QLPU criteria would have required additional units to run, keeping system inertia high, thus reducing the possibility of a load shed.

POTENTIAL CHANGES IN CAPACITY PLANNING

Consideration for a More Conservative LOLP Guideline

Perhaps the time has come to consider a more conservative Loss-of-Load Probability (LOLP) guideline of 4½ years per day. With the rapid influx of renewable generation (mostly DG-PV), the current LOLP guideline and current system conditions point to a greater potential for repeat outages in the future. The rise in DG-PV creates additional planning challenges. In 2006, the Consumer Advocate suggested a change to 6 years per day. Such a change would be coupled with increased costs.

This more conservative LOLP, however, would begin to address the increasing uncertainty in our capacity planning.

The Need for a Higher Reserve Margin of 30%

Increasing amounts of DG-PV challenge our ability to maintain an adequate reserve margin. Currently, system planning aims to exceed a 20% reserve margin. This increased amount of variable generation, and its resultant system-related consequences, warrants a more realistic 30% reserve margin

We are currently assigning capacity values to demand response, utility-scale renewable generation (including wind and PV), and energy storage to be used in calculating future reserve margins. The ever increasing amounts of uncontrollable DG-PV coupled with increasing peak demand forecasts form the more fundamental factors for raising our reserve margin threshold to 30%.

OTHER POTENTIAL MITIGATION MEASURES

A number of additional measures could potentially mitigate future generations shortfalls, or at least minimize their impact.

Schofield Generating System. A 50 MW utility-owned, fast-starting firm generation unit installed on the Schofield Barracks Army facility not only would increase reliability, but also enable more renewable generation to be integrated onto the grid.

Replacement Firm Generation. Replacing our current firm generation with newer, fast-starting units would potentially improve reliability. New units require less maintenance and are more reliable.

Effects of a Battery Energy Storage System (BESS). The inertial response from a 130 MW battery energy storage system (BESS) would have most likely prevented UFLS during the AES trip event. A 200 MW BESS could provide regulating reserve. A 100 MW BESS could provide contingency reserve. All of these storage systems would mitigate generation shortfalls, albeit for about an hour.

Customer-Sited Emergency Generators. Activating these generators would immediately reduce demand during a contingency event. The stalled Airport DSG project would add 8 MW of quick-starting generation to lessen a generation shortfall. These generators could render small contingencies avoidable.

Demand Response (DR). Demand Response (DR) programs give grid operators more flexibility when balancing supply and demand, and can contribute regulating reserve, contingency reserve, and non-spinning reserve. Greater enrollments and more robust programs can contribute to these advantages.

Smart Grid Technology and Implementation. Smart Grid would benefit the operation and reliability power grid.

A Demand Response Management System (DRMS) would make DR programs more effective. An Advanced Distribution Management System (ADMS), integrated into the DRMS, would increase information about how the power grid is operating, and thus make it more manageable. The two-way communication provided by the AMI mesh network would provide accurate information (such as available loads).

Many other Smart Grid solutions could also enhance grid reliability. Solutions such as a critical peak pricing, battery storage, and a Customer Facing Solution (CFS) enable customers them to be a more active participant in managing demand. These solutions would allow us additional methods for managing demand too.

MATS (Mercury and Air Toxics Standards) Compliance. As it currently stands, MATS compliance only serves to reduce unit availability. We are investigating several methods for minimizing, it not completely eliminating, this impact.

Independent Power Producer Contingencies. Increasing amounts of DG-PV reduce daytime loads, thus increasing the percentage of total generation provided by AES, our largest and lowest cost unit. Thus, when AES trips offline, the resultant contingency will only become more and more difficult to stabilize. This possibility becomes greater because we are increasingly not starting our cycling units during the day, leaving even less generation available to respond to a contingency.

Underfrequency Load Shedding. The load shedding schemes are a trade-off. These schemes shed load blocks at higher system frequencies, containing the extent and duration of outages, but drastically reduce the possibility of an island-wide outage. As a result, a smaller number of customers are affected by outages, although potentially more frequently.

Grid Modernization. Increasing amounts of DG-PV and other renewable resources, combined with decreasing output from firm generation, compels us to modernize our grid and generation fleet to manage the shifting priorities precipitated by such a shift.

The O'ahu grid needs new firm generating units with greater operational flexibility to replace current generation. Our transmission and distribution system must also be modernized. This modernization must also incorporate Smart Grid solutions.

This full scope of grid modernization would enable increasing amounts of renewable generation, considerably enhance our system reliability, and lower the potential for future generation shortfalls.

Distributed Generation Photovoltaics and Customer-Side Energy Storage. Generation shortfalls almost always occur during evening peak—at a time when DG-PV does not generate power. Customers with high-cost battery storage units would limit any such generation shortfall. To be effective, however, these storage systems must operate independent of the grid.

New Contractual Terms for Future Power Purchase Agreements. Current power purchase agreements (PPAs) pay (IPPs) on a combination of available firm capacity and the amount of energy delivered, thus enticing them generate as much as possible while perhaps foregoing necessary maintenance. Future PPAs must contain incentives and sanctions to ensure proper maintenance together with high availability.

1. Introduction

On 12 January 2015, the electric power grid on O'ahu experienced a confluence of events (involving ten generating units) that led first to a brief afternoon outage, and then to longer rolling outages during evening peak demand. The brief (2 to 6 minutes) afternoon outage affected about 22,000 customers; the evening rolling outages affected almost 29,000 customers.

Our intent with this report is to give some perspective to these events, to draw reasonable conclusions, and to itemize some recommendations for action. Toward that end, the report documents the causes of this trip event, assesses our efforts to communicate the event, analyzes the overriding factors that contributed to the event, assesses the probability of future generation shortfalls, and points out how escalating amounts of distributed photovoltaic generation (DG-PV) contributed to the event and increase the likelihood of future trip events.

OVERVIEW OF THE TRIP EVENT

Several factors contributed to the two outages of 12 January 2015. Two unit trips (Kahe 5 and AES) combined with three units on both planned and last-minute forced outages (Kahe 6, Waiau 9, and Kalaeloa CT-2), four derates (Kahe 1, Waiau 6, H-POWER[1], and Kalaeloa CT-1), and one unit on maintenance (Kahe 4)—together with our wind units generating only minimal amounts—drastically reduced our generating capacity by well over 40%.

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[1] H-POWER stands for Honolulu Program of Waste Energy Recovery; operated by Covanta Honolulu Resource Recovery Venture (HRRV), LLC.

During the afternoon, our call for energy conservation combined with demand response dispatches did not reduce demand enough to avoid the evening rolling outages—especially since virtually all DG-PV generation stopped.

The rolling outages lasted a little less than an hour and a half. Reaction to this outage was further exacerbated by its unfortunate timing—it coincided with the college BCS Championship football game featuring Marcus Mariota, a Honolulu-born Samoan and local fan favorite.

Our last significant outage occurred a little over six years ago. Our Capacity Planning Criteria is built upon the principle of one outage day every four and a half years. Viewed from this larger perspective, the 12 January 2015 outage fell well within our planning guidelines.

Recovering from the tripping of our two largest generating units is a difficult task. In early morning, Kahe 5 tripped removing 142 MW from the power grid. In early afternoon, AES tripped over a period of about five minutes, removing all of its 180 MW. The AES trip also caused about 25 MW of legacy PV to also trip. In addition, our utility-scale wind generation, with a combined capacity of 99 MW, was generating at most only 5 MW for the remainder of the day and night.

During the afternoon however, we were able to successfully generate enough power to meet demand by starting Waiau 9 and Waiau 10, adding 91 MW to our power grid. Unfortunately, Waiau 9 experienced a problem during the afternoon and was fully derated. The problems on Waiau 9 were corrected, and the unit was back online by mid-afternoon.

Immediate efforts to restore power to Kahe 5 and AES proved unsuccessful. We quickly realized that even by committing the 113 MW generated by CIP CT-1, we would experience a generation shortfall during evening peak when the grid would also lose all DG-PV. This led directly to our shedding load, starting in the early evening (about 6:20 PM).

OUR EVOLVING GENERATION MIX

We carefully plan unit maintenance. We never maintain a unit unless we are sure that there is enough available reserve generation without that particular unit being online. If a possibility exists for not having enough reserve generation, we postpone maintenance until we are certain that we can reliably operate the power grid without that unit.

More DG-PV increases the challenge for operating a reliable system. The continuing influx of DG-PV in our generation mix has changed our power grid, forcing us to continually adjust how we plan, maintain, and generate enough power to meet demand. There are many ramifications.

Our firm generation units are not running as they were designed. As a result, they are being maintained more often. Even with this increased maintenance, they tend to experience more problems which can exacerbate generation shortfalls resulting in cascading outages.

Our firm generation units are operating at lower thresholds, forcing us to make adjustments so that they can operate more efficiently. One adjustment is to run the unit at decreased power, generating less MW than their design specification. This adjustment, however, creates dirtier boilers and thus increases maintenance. Another adjustment is to simply turn off the unit. This creates two problems. First, turning off the unit decreases the amount of inertia on the system, making the power grid more vulnerable and thus less reliable. Second, these units ramp slowly, so their ability to respond to generation shortfalls is limited.

AES Hawai'i, our largest unit powered by coal, tripping offline causes the biggest problem mainly because of the generation that must be replaced to maintain a reliable reserve margin. AES Hawai'i continues to age, and has shown a tendency to trip more often in recent years, creating further challenges for our system planners.

Our system operators do not know, with any precision, the amount of DG-PV running on the power grid throughout the day. Instead, they estimate. As a result, the spinning reserve requirements become increasingly ambiguous and thus more challenging to maintain. Carrying more spinning reserve than necessary increases costs; carrying less spinning reserve compromises system reliability.

Finally, increasing amounts of DG-PV challenge our ability to maintain an adequate reserve margin—a situation amplified when daily demand is at its peak, in the evening when DG-PV does not generate. We constantly adjust to changes in the generation mix so that we can respond as needed, both now and into the future.

O'AHU GENERATION

Knowing Hawaiian Electric's generation capacity is vital to understanding the challenges we face in maintaining a reliable power grid. Our grid has a mix of utility-owned independent power producers (IPPs) firm and variable generation.

Unit	Fuel	Gross	AOS Rating	Type	Generation
Hawaiian Electric Units					
Kahe 1	LSFO	86.0	88.2	Baseload	Steam
Kahe 2	LSFO	86.0	86.3	Baseload	Steam
Kahe 3	LSFO	90.0	88.2	Baseload	Steam
Kahe 4	LSFO	89.0	89.2	Baseload	Steam
Kahe 5	LSFO	142.0	134.7	Baseload	Steam
Kahe 6	LSFO	142.0	133.9	Baseload	Steam
Waiau 3	LSFO	49.0	46.2	Cycling	Steam
Waiau 4	LSFO	49.0	46.4	Cycling	Steam
Waiau 5	LSFO	57.0	54.6	Cycling	Steam
Waiau 6	LSFO	56.0	55.6	Cycling	Steam
Waiau 7	LSFO	87.0	88.1	Baseload	Steam
Waiau 8	LSFO	90.0	88.1	Baseload	Steam
Waiau 9 (CT)	LSFO	47.0	51.9	Quick-Start Peaker	Diesel
Waiau 10 (CT)	LSFO	44.0	49.9	Quick-Start Peaker	Diesel
Campbell Industrial Park (CIP) CT-1	Biodiesel	113.0	113.0	Quick-Start Peaker	Diesel
Total	—	*1,227.0*	*1,214.3*	—	—
IPP (Independent Power Producers)					
AES	Coal	180.0	180.0	Baseload	Steam
H-POWER (HRRV)	Refuse	68.5	68.5	Baseload	Steam
Kalaeloa (KPLP) CT-1	LSFO	104.0	104.0	Baseload	Steam
Kalaeloa (KPLP) CT-2	LSFO	104.0	104.0	Baseload	Steam
Kapolei Sustainable Energy Park (Tesoro)	PV	1.0	—	Variable	Solar Panels
Kalaeloa Solar Two (KS2)	PV	5.0	—	Variable	Solar Panels
Kalaeloa Renewable Energy Park (KREP)	PV	5.0	—	Variable	Solar Panels
Kawailoa (Mauka)	Wind	49.0	—	Variable	Turbines
Kawailoa (Makai)	Wind	20.0	—	Variable	Turbines
Kahuku	Wind	30.0	—	Variable	Turbines
Total	—	*566.5*	*456.5*	—	—
Totals	**—**	**1,793.5**	**1670.8**	**—**	**—**

Table 1. O'ahu Generation Units

Our system planners use a certain unit rating to develop their annual adequacy of supply (AOS). The total net generation of 1,214.3 MW represents the optimal net generating capability rating to calculate the AOS.

Over the years, the top load gross ratings have been adjusted for operational inefficiencies between overhauls. The AOS ratings were developed a number of years ago; we have continued to use them to maintain consistency in our annual reporting and to better compare and contrast our AOS year by year.

OVERVIEW OF THIS REPORT

The report comprises eight chapters and nine appendices. The overall tenor of the report is to comprehensively describe the events surrounding the outage, and to give those events a larger perspective.

Here is a breakdown of the contents of this report.

Chapter 1. Introduction: Overviews the trip event and resultant outages, and details our basic generation capacity.

Chapter 2. January Events: Describes, in comprehensive detail, the events that resulted in the trip event and rolling outages.

Chapter 3. Internal and External Communication: Chronicles how we communicated information about the event to our staff, the news media, and our customers.

Chapter 4. Customer Communication: Recounts the interactions between our Customer Service department and our customers.

Chapter 5. Event Analysis: Analyzes the fundamentals behind generation planning and how they apply to this trip event.

Chapter 6. Solar Generation's Impact: Explains how increasing amounts of photovoltaic generation affect our reliability planning.

Chapter 7. Potential for Future Generation Shortfalls: Discusses how our Capacity Planning Criteria affects reliability, and discusses potential mitigating solutions.

Chapter 8. Conclusions and Recommendations: Summarizes the conclusions we reached from analyzing the information garnered from the trip event and outage, and explains cogent recommendations for thoughtful consideration.

Appendices A–I: Contains supplemental and more in-depth information in support of various sections of the main report.

2. January Events

Through a combination of trip events, forced outages, derates, planned outages, and extremely low renewable generation, Hawaiian Electric was compelled to initiate manual load sheds—a series of rolling outages—on the evening of January 12, 2015.

The unavailable firm generation (both utility-owned and IPP) totaled 737 MW, which represented 43.8% of total generating capacity. The approaching dark of the evening removed all PV generation from the power grid, as well as negligible wind generation only increased this unavailable capacity. As a result, only 947 MW of generation (out of a total firm capacity of 1,684 MW) was available to meet an evening peak load projected to be over 1,030 MW.

The resultant rolling outages were the first such event in over six years.

SUMMARY OF THE TRIP EVENT

January 12, 2015 started with 335 MW of capacity already offline (Kahe 4, Kahe 6, and Kalaeloa CT-2). With these units offline, system inertia was low. As the day progressed, high levels of DG-PV generation forced other firm generation from running on the power grid, decreasing system inertia even more.

In the early morning, Kahe 5 tripped offline, removing an additional 142 MW from available capacity—now totaling 477 MW. Our residential under-frequency load control program, EnergyScout, activated and quickly restored the stability of the power grid. Two demand response programs (RDLC and CIDLC) automatically activated.

In early afternoon (at approximately 1:43 PM), one of AES boiler tripped offline, losing 110 MW of its total capacity. We dispatched Waiau 9 to make up to 53 MW available. Five minutes later, AES appeared to stabilize. Four minutes later (at approximately

1:52 PM), the other AES boiler tripped, losing its remaining 70 MW of capacity. Immediately, system frequency dropped, reaching a nadir on 58.837 Hz before stabilizing. Frequency recovered after about 30 seconds.

Once system frequency dropped, a number of events occurred simultaneously. Our EnergyScout automatic under-frequency load control program activated. Our RDLC and then our CIDLC demand response programs automatically activated. Approximately 25 MW of DG-PV tripped offline further exacerbating the contingency. Our under-frequency load shed (UFLS) scheme activated, initiating one block of load shed. About 20,000 customers lost power from two to six minutes, when the system was fully restored.

By mid afternoon, we realized that not enough generation would be available to meet evening peak. At various times and for miscellaneous reasons, five units were derated for a cumulative loss of 133 MW. Low wind generation (about 4 MW) compounded the problem. We made the decision to initiate rolling outages starting at about 6:00 PM. We began informing the media and the public of our intentions.

At 5:30 PM, we dispatched the CIDLC program, followed a half hour later by the RDLC program. About 20 minutes later, we initiated the first block of manual load shed for a little more than an hour. Two minutes before restoring the first load shed block, we initiated the second block of manual load shed, this time for about ½ an hour. About half way into the second load shed block, we restored RDLC then restored CIDLC about 20 minute later. By 8:00 PM, the system was back to normal operations.

None of the customers affected by the afternoon load shed were affected by the evening rolling outages. Similarly, none of the customers affected by the evening rolling outages were affected by the afternoon load shed.

Our capacity planning criteria anticipates that such an event might occur once every 4½ years. The last such outage occurred a little over six years ago.

About Our Demand Response (DR) Programs

We currently offer three DR programs: the Residential Direct Load Control (RDLC) program has approximately 14.7 MW enrolled; the Commercial and Industrial Direct Load Control (CIDLC) program has approximately 12.7 MW enrolled; and the FastDR program has approximately 7 MW enrolled.

In response to under-frequency events, the RDLC automatically dispatches when frequency drops to 59.7 Hz; the CIDLC automatically dispatches when frequency drops to 59.5 Hz. The average dispatch response time is after about 60 cycles (or one minute). When system frequency reaches these levels, the devices enrolled in the DR programs sends a signal to dispatch and trip. In general, because of system conditions, RDLC trips offline about 7–8 MW while CIDLC trips offline about 8–9 MW.

System operators can also manually dispatch these DR programs. In general, they try to dispatch them for at most an hour, but certain situations can change that duration. Oftentimes, they run these programs for short periods of time, dispatching them when they are most needed, using them quickly and efficiently to balance output and demand while maintaining a stable system frequency.

System operators makes every attempt to stagger the dispatch of these DR programs to cover as large an area and the most MW as possible. These programs are always dispatched island-wide.

GENERATION STATUS SURROUNDING THE TRIP EVENT

A number of units were derated or unavailable on January 12, 2015 before the AES trip event. Following the trip, an additional Hawaiian Electric unit was forced offline.

Unit	Gross Capacity	Derate	Available Capacity	Reason
Kahe 1	86	–11	75	Fuel oil supply control instability since January 10, 2015; however full output was provided on governor response.
Kahe 4	89	–89	0	On planned maintenance since December 18, 2014.
Kahe 5	142	–142	0	Tripped offline at 0526 January 12, 2015; returned to service 1027 January 13, 2015.
Kahe 6	142	–142	0	Forced outage because of a problem with its main step-up transformer since October 10, 2014.
Waiau 6	56	–21	35	Its governor was blocked at 35 MW because of a boiler hot spot since January 8, 2015.
H-POWER	69	–34	35	Not enough fuel to attain maximum output.
Kalaeloa CT-1	104	–14	90	Limitations from the heat recovery steam generator (HRSG) because Kalaeloa CT-2 was offline.
Kalaeloa CT-2	104	–104	0	Forced outage because of a compressor blade failure in December 9, 2014.
Before AES Trip	—	*557*	*235*	*Total derated capacity before the AES trip*
AES Hawai'i	180	–180	0	Tripped offline at 1352, January 12, 2015
Waiau 9	47	0	47	Output decreased to zero after its inertial response because of a control problem, which were corrected by midafternoon.
After AES Trip	—	*737*	*47*	*Total derated capacity after the AES trip*
Total Firm Capacity	1,684	737	947	Available capacity for evening peak: 56.2% of firm generating capacity

Table 2. Unavailable and Derated Units on January 12, 2015

Kahe 4 and Kahe 6 were unavailable due to maintenance;. Kahe 5 was expected to be online, but the unit tripped offline at 5:26 AM (and didn't return to service until January 13 at 10:27 AM.). Kalaeloa CT-2 was unavailable due to maintenance on its compressor blade, which forced Kalaeloa CT-1 to be derated to 90 MW (–14 MW derate) because of limitations from the unit's heat recovery steam generator (HRSG). Waiau 6 had blocked its governor at 35MW due to a boiler hot spot. Kahe 1 was derated –11 MW because of fuel supply instability, however, the unit responded with full output on governor response when AES tripped offline.

H-POWER initially was derated –34 MW because of insufficient fuel to operate at full capacity. H-POWER derates themselves when they don't have enough fuel to burn to reach their maximum output. They estimate the derate. When dispatched in response to the AES trip event and to help meet evening peak, H-POWER responded with 59 MW of power. Waiau 9, while initially available after the AES trip, developed control problems when starting up and had to be forced offline. These control problems were rectified, and the unit was back online by 2:45 PM to serve evening peak.

Thus approximately 33% of the system's firm generation was unavailable prior to the AES trip event. After the AES trip event coupled with the loss of Waiau 9, approximately 43.8% of firm generating capacity was unavailable to meet evening peak demand.

TIMELINE OF THE TRIP EVENT AND RESULTANT OUTAGES

What follows is a timeline of a detailed retelling of the events of January 12, 2015. Times use a 24-hour clock format.

Monday, January 12, 2015

00:01 The day begins with 415 MW of utility-owned and IPP generation offline or derated for a number of reasons. (See Table 2 on page 18 for details.) This meant that almost 25% of total generation is unavailable to meet demand.

05:38 Kahe 5 unexpectedly trips offline, causing an additional loss of 142 MW. A total of 557 MW of generation is now unavailable, representing approximately 33% of total generation.

The residential EnergyScout automatic under-frequency (UF) load control program activates to attempt to restore the situation.

When system frequency drops to 59.7 Hz, the under frequency causes Residential Direct Load Control (RDLC) demand response (DR) program to automatically dispatch, which reduces load by approximately 6.6 MW. Total capacity of RDLC is approximately 14.7 MW. (The exact dispatch time is 05:37:39; the exact system frequency is 59.64 Hz.)

System frequency does not drop low enough to automatically dispatch the CIDLC program.

05:40 EnergyScout restores the power grid to a stable condition.

The RDLC program is restored.

13:43 These were the system conditions before the AES Boiler B experienced trouble:

- System load was 800 MW.
- Spinning reserve was 209 MW.
- Quick Load Pick Up (QLPU) was 144 MW.
- Estimated Legacy PV was about 25 MW.
- Wind generation was approximately 4 MW (out of an available capacity of 99 MW).

13:43:05 The AES Hawai'i generator was put on local control because a tube leak in Boiler B instigated an emergency situation. AES operators called Hawaiian Electric over the generation hotline to announce the contingency and their intentions to try to stabilize the unit. Over the next five minutes, AES personnel tried to ramp down Boiler B in a controlled manner to avoid a complete AES outage. During those five minutes, output decayed from its full generation of 180 MW to about 70 MW—a loss of 110 MW. With the ramp down fully implemented, AES Boiler B tripped offline.

During this ramp down, system frequency dropped to nadir of 59.71 Hz.

The remaining units responded to arrest frequency decay. Automatic generation control (AGC) restored system frequency to 60 Hz.

During this time, anticipating the deficiency in generation and spinning reserve capacity, Hawaiian Electric turned on Waiau 9 (a quick-start unit), trying to bring online up to 53 MW to operating spinning reserve (OSR). The addition of Waiau 9 increased the total excess operating spinning reserve (XOSR) to approximately 48 MW. This total included approximately 8 MW of variable generation, virtually all of which was rooftop distributed generation photovoltaic (DG-PV) generation.

After its initial inertia response, Waiau 9 experienced control problems, decreased its output, and was eventually shut down. The loss of its 47 MW brought the total of unavailable capacity to 784 MW, or about 46.5% of all generating capacity.

H-POWER's output was ramped up to 59 MW to provide capacity from the loss experienced by the AES boiler trip, and kept at that level to provide capacity during evening peak.

13:48 AES maintained generation of about 70 MW for the next four minutes as the unit appeared to stabilize. Boiler B tripping disrupted Boiler A, causing the control system to trip to manual mode. Attempts to stabilize Boiler A were unsuccessful, so it eventually tripped.

These were the system conditions before the AES turbine tripped:

- System load was 795 MW.
- Spinning reserve was approximately 100 MW because of the Waiau 9 control problems.
- Quick Load Pick Up (QLPU) was 75 MW because of the Waiau 9 control problems.
- AES had only 70 MW available capacity.
- Estimated Legacy PV was about 25 MW.
- Wind generation was approximately 4 MW (out of an available capacity of 99 MW).

13:52:25 After maintaining its reduced generation for four minutes, AES lost Boiler A and the unit fully tripped offline. This caused the AES turbine to trip offline. The unit's remaining capacity of 70 MW was then lost. AES generation of 180 MW represented 23% of the system load when it began to trip offline. The total loss of AES added 180 MW to the climbing total of unavailable generation, now at 737 MW, representing almost 44% of total generating capacity.

The Hawaiian Electric system continued to carry 9 MW of AES's auxiliary load for 7 seconds until the breaker tripped on reverse power. Over those same 7 seconds, system frequency plummeted to a nadir of 58.837 Hz. (See Figure 3 on page 28 for details.) This dropping frequency caused a number of restoration actions to automatically dispatch.

In response to the unit fully tripping offline, our EnergyScout automatic under-frequency (UF) load control program activated. The Energy Management System (EMS) activates, sending text and email messages to key personnel throughout the company.

13:52:28 When frequency reached 59.3 Hz (at slightly less than 3 seconds after the full AES trip), the IEEE 1547-PV interconnection standard activated. This caused approximately 25 MW of Legacy PV to trip offline, increasing the capacity loss to 205 MW, thus exacerbating the contingency event.

13:52:31 When system frequency dropped to 59.7 Hz, the RDLC program activated. The RDLC actually dispatched when frequency reached 58.83 Hz. This demand response program reduced the overall system load by approximately 0.62 MW.

13:52:31 When system frequency reached 59.5 Hz, the CIDLC program activated. The CIDLC actually dispatch when frequency reached 58.83 Hz. This demand response programs reduced the overall system load by approximately 0.62 MW.

13:52:31 When system frequency reached 59.0 Hz, Hawaiian Electric's under-frequency load shedding (UFLS) scheme activated the Kicker Block 1 and Kicker Block load shed schemes. Because a Kicker Block 1 has a 5 second delay, this load shed never dispatched because system frequency has sufficiently recovered before the 5 seconds expired. Kicker Block 2 has a 10 second delay, so it too never dispatched.

13:52:32 When system frequency reached 58.9 Hz, Hawaiian Electric's under-frequency load shedding (UFLS) scheme activated a Block 1 load shed to help stabilize the system.

The UFLS event caused brief outages (from 2 to 6 minutes) for approximately 20,325 customers in the Kailua, Kaneohe, Maunawili, Halawa, Salt Lake, Aliamanu, Wailupe, Pearl City, Waimano, Waimalu, and Waipahu.

These outages affected distribution circuits … which circuits were affected?

Figure 2 shows the frequency response profile to the AES turbine trip and the relevant frequency triggers for load demand response programs, Legacy PV, and UFLS blocks.

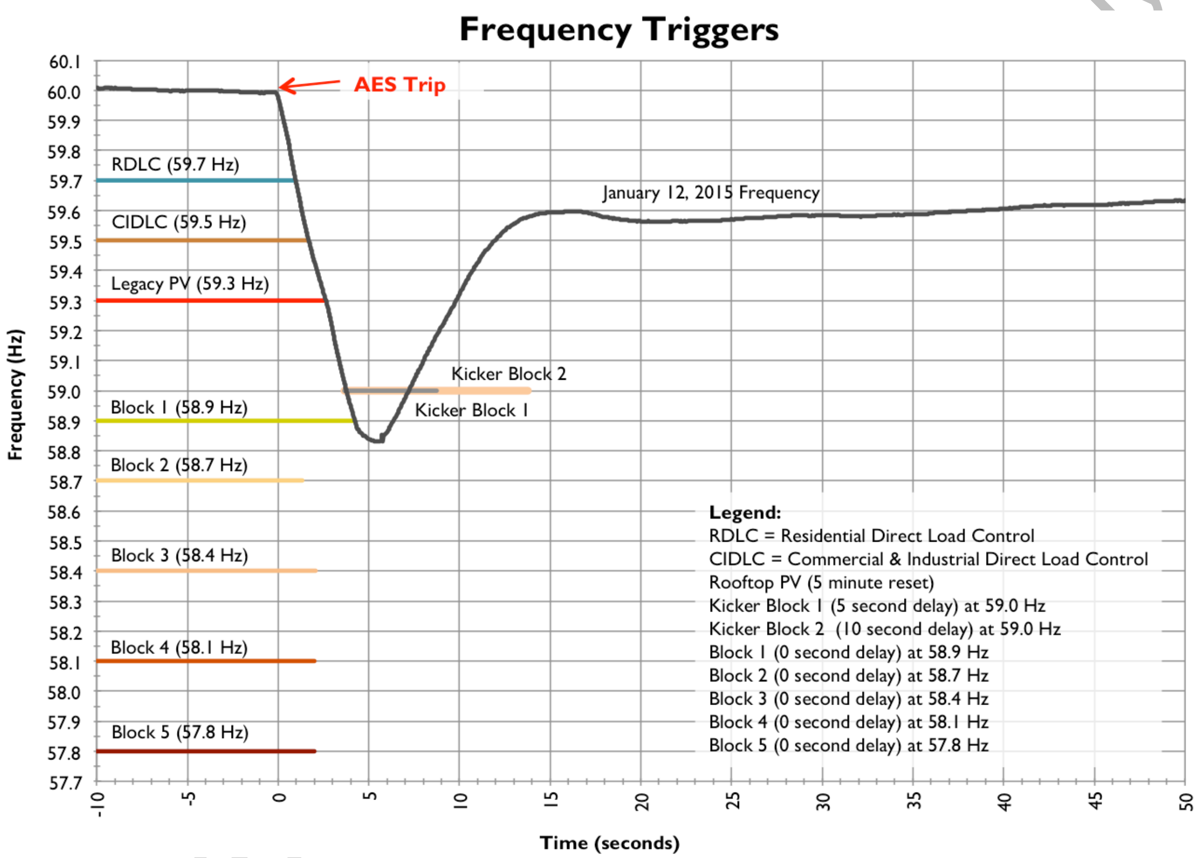

Figure 2. Frequency Triggers (from Tesla Data)

13:52:33 When frequency reached its nadir of 58.837 Hz, the system began to recover.

13:52:40 AGC recovered system frequency to 59.6 Hz about 15 seconds after AES fully tripped offline. Frequency leveled

13:52:55 System frequency leveled off at approximately 59.58 Hz after about 30 seconds after the AES trip event.

13:54 Some customers begin to have their power restored.

13:58 AGC restored frequency to normal six minutes after the AES trip event. Power to all affected customers is fully restored.

Both the RDLC and CIDLC programs are restored after running for about 4 minutes each.

14:30 Between 2:30 PM and 3:00 PM, System Operations forecasted a generation shortfall during evening peak. Projections showed that insufficient amounts of wind generation would be available to potentially avoid the rolling outage. It's interesting to note that had the Airport Dispatchable Standby Generation (DSG) project been online with its 8 MW, between 8,000 and 10,000 fewer customers would have been affected by the rolling outages.

System Operations began communicating with Corporate Communication to assess them of the situation. From these conversations, Corporate Communication issued a number of news releases, held a press conferences, and engaged in social media postings to inform the public and the news media about the situation. Corporate Communication issued an appeal for energy conservation during the peak demand hours of 5:00 PM until 9:00 PM, and released a schedule of planned rolling outages together with the affected areas. None of the areas affected by the afternoon UFLS outages were affected by the rolling outages.

15:30 Corporate Communication issues a plea for energy conservation during the evening peak period. Estimates for its effectiveness approach 8 MW.

16:30 BCS Championship Football game between Ohio State and the Oregon Ducks, featuring local fan favorite and Honolulu-born Marcus Mariota. The rolling outages affects some customers watching the game, which led to the majority of recorded complaints about the outages.

18:03 System operators dispatch the RDLC program to mitigate evening peak load, prior to manual load shed. This reduces demand by approximately 8 MW. Approximately 24,000 customers are affected, having their electric water heaters temporarily de-energized (turned off). Without the load shed from RDLC, we might have needed to manually load shed a third 46kV circuit for each block. As it stood, we only needed to load shed two 46kV circuits.

18:23 System Operations initiated the first manual load shed (2-46kV CBs Open command) on the School–Nuʻuanu and the School–Puʻunui 46kV circuits. The outage affected approximately 13,970 customer in the Pauoa, Fort Street, Puʻunui Heights, Nuʻuanu, School Street, and Kapalama areas. The outage lasted one hour and two minutes, reducing load by 18 MW

19:23 System Operations initiated the second manual load shed (2-46kV CBs Open command) for the Ko'olau–Wailupe 1&2 46kV circuits. This second outage was initiated to prepare for the restoration of power to customers affected by the first manual load shed. The outage affected approximately 14,870 customers in the Hawai'i Kai and Waimanalo areas. The outage lasted 23 minutes, reducing load by 17 MW.

19:25 System Operations restored power to customers affected by the first manual load shed: School–Nu'uanu and School–Pu'unui circuits.

19:46 System Operations restored power to customers affected by the second manual load shed: Ko'olau–Wailupe 1&2 circuits.

20:15 System operators restore the RDLC program, turning back on customer water heaters.

Tuesday, January 13, 2015

09:30 Customers again asked to conserve electricity during the day's evening peak period (time uncertain).

17:30 System operators dispatch the CIDLC program to mitigate evening peak load. This reduces demand by approximately 10 MW.

18:00 System operators dispatch the FastDR program to mitigate evening peak load. This reduces demand by approximately 3 MW.

18:33 System operators dispatch the RDLC program to mitigate evening peak load. This reduces demand by approximately 12 MW.

19:00 System operators restore the FastDR program.

19:30 System operators restore the CIDLC program.

19:33 System operators restore the RDLC program.

Wednesday, January 14, 2015

09:30 Calls for energy conservation lifted (time uncertain).

17:30 System operators dispatch the CIDLC program to mitigate evening peak load. This reduces demand by approximately 10 MW.

18:00 System operators dispatch the FastDR program to mitigate evening peak load. This reduces demand by approximately 2 MW.

18:21 System operators dispatch the RDLC program to mitigate evening peak load. This reduces demand by approximately 10 MW.

19:00 System operators restore the FastDR program.

19:21 System operators restore the RDLC program.

19:30 System operators restore the CIDLC program.

Thursday, January 15, 2015

17:30 System operators dispatch the CIDLC program to mitigate evening peak load. This reduces demand by approximately 10 MW.

18:00 System operators dispatch the FastDR program to mitigate evening peak load. This reduces demand by approximately 3 MW.

18:19 System operators dispatch the RDLC program to mitigate evening peak load. This reduces demand by approximately 8 MW.

19:00 System operators restore the FastDR program.

19:19 System operators restore the RDLC program.

19:30 System operators restore the CIDLC program.

FACTORS CONTRIBUTING TO LOAD SHEDDING

A number of additional factors contributed to the load shedding and rolling outages.

Multiple Contingencies. Multiple contingencies contributed to this outage event. The rolling outages would have been avoided if either AES or Kahe 5 remained online. With both units offline, low system inertia also contributed to the contingency. The current UFLS scheme, with higher trip points, could result in more load shedding when one large generator (AES, Kahe 5, or Kahe 6) trips offline, especially when excess operating spinning reserve (XOSR) is minimal. The tripping of DG-PV only serves to exacerbate the contingency, which might have caused three blocks of load shedding. The UFLS was limited to one block because the AES ramp down afforded us the opportunity to dispatch units which reduced the load shed to one block.

Larger Contingency Than Appeared. To our UFLS scheme, the AES turbine trip appeared to retain 70 MW of generating power that triggered a Block 1 load shed. The actual magnitude of the generation contingency loss, however, included the 9 MW net generation output of AES auxiliary loads carried by the system plus the approximate 25 MW of Legacy PV that disconnected from the system at 59.3 Hz. Thus, the total loss of generation contingency was approximately 104 MW.

The Proliferation of DG-PV: Changed Unit Commitment Criteria. Increasing amounts DG-PV continues to reduce daytime loads, thus displacing synchronous generation and lowering system inertia.

System Operations historically committed units to meet a three-second Quick Load Pick Up (QLPU) criteria. The policy was based on the original UFLS setting of 58.5 Hz which covered the 142 MW capacity of Kahe 5 or Kahe 6. System Operations commonly committed additional units to run the system with excess QLPU under certain conditions (for example, when system load was low, and a Kalaeloa CT together with a large steam unit was offline for maintenance). Under these conditions, System Operations would commit two or three additional cycling units to prevent UFLS. With the new UFLS scheme, increasing amounts of Legacy PV, and adoption of the TPL-001 standard that allows 12% of the customer load to be shed for a single loss of generation contingency, the QLPU criteria for unit commitment is no longer in effect.

The Proliferation of DG-PV: Lower System Inertia. System inertia is lower because DG-PV has displaced synchronous generation. To compound this problem, our largest units have high inertia constant H values: both Kahe 5 and Kahe 6 are 6.92 MJ/MVA, and Kalaeloa CT-2 is 5.91 MJ/MVA. (See "Appendix G. Generator Inertia Constant H Values" on page 143 for an explanation of constant H and a list of values for all thermal units.) The obsolete QLPU criteria would have required additional units to run, then reducing the possibility of a load shed. Instead, these three high inertia units were offline during this AES trip event, keeping system inertia was low.

Low system inertia caused by increasing amounts of PV is not just a Hawaiian Electric problem. A recent study[2] corroborates this situation:

> The traditional assumption that grid inertia is sufficiently high with only small variations over time is thus not valid for power systems with high renewable energy sources. This has implications for frequency dynamics and power system stability and operation. Frequency dynamics are faster in power systems with low rotational inertia, making frequency control and power system operation more challenging.

The Proliferation of DG-PV: An Uncontrollable Resource. This AES trip event validates earlier assessments that we must evaluate additional mitigation efforts to manage a loss of generation contingency during the day because DG-PV is not a controllable resource. In additional, DG-PV running at high levels reduces daytime system load. When our largest unit, AES, trips at full capacity, contingency reserves (such as governor droop

[2] *Impact of Low Rotational Inertia on Power System Stability and Operation*, by Andreas Ulbig, Theodor S. Borsche, and Göran Andersson; Power Systems Laboratory, ETH Zurich, published 22 December 2014 (http://arxiv.org/pdf/1312.6435.pdf); page 1.

and demand response) are ineffective in arresting system frequency. Thus, UFLS is required to stabilize the system.

For this AES trip the initial AES ramp down gave us some time to commit Waiau 10, so the loss of generation contingency was less severe.

The Proliferation of DG-PV: IEEE 1547 Trip Settings. "The amount of DG-PV that cannot be retrofitted to the meet the proposed ride-through settings is critical for the security of the power system. The existing amount of DG-PV tripping for original standard IEEE 1547 trip settings on the Hawaiian Electric system is estimated to be 70 MW. With 70 MW of legacy DG-PV, the system cannot survive the largest contingency. As the legacy DG-PV is reduced, the system response improves. The maximum amount of legacy DG-PV is recommended to be no more than 40 MW. This level of legacy DG-PV still results in significant load shedding and violations of TPL-001, however, the power system would be more resistant to collapse."[3]

Unreliable Wind Generation. As happens every day when the sun sets, our PV systems and DG-PV were not producing power during evening peak. In addition, wind generation is unreliable to be dispatched, thus compounding our efforts to meet demand. On January 12, 2015, wind generated very little: approximately 0.2 MW to 3.6 MW out of a total 99 MW of nameplate capacity.

Effects of a Battery Energy Storage System (BESS). Our simulations demonstrated that the inertial response from a 130 MW battery energy storage system (BESS) would have prevented UFLS. Before installing such a contingency BESS, however, we could instigate other mitigation measures: first, dispatch AES to a lower output to control the magnitude of the contingency event; second, commit additional units to maintain a minimum system inertia; and third, reduce the impact of DG-PV.

3 *Hawaiian Electric Power Supply Improvement Plan (PSIP)*, filed on 26 August 2014 in Docket No. 2011-0206 (http://files.hawaii.gov/puc/3_Dkt%202011-0206%202014-08-26%20HECO%20PSIP%20Report.pdf); page 4-40.

A CLOSER LOOK AT THE TRIP EVENT

AES Boiler and Turbine Trip

At 1:43:05 PM, AES tripped one of its boilers due to a tube leak, causing its output to ramp down from 180 MW to 70 MW in five minutes. AES appeared to stabilize for about four minutes before a second boiler and turbine tripped at 1:52:25 PM. Our Energy Management System (EMS) PI recorded AES breakers CB323, CB324, CB321, and CB457 all opening at the exact time of the second boiler trip. CB347, which provides auxiliary power to AES, however, remained closed for seven seconds.

Figure 3 shows the negative load of 9 MW caused while CB347 remained closed, which corresponds to the AES auxiliary load.

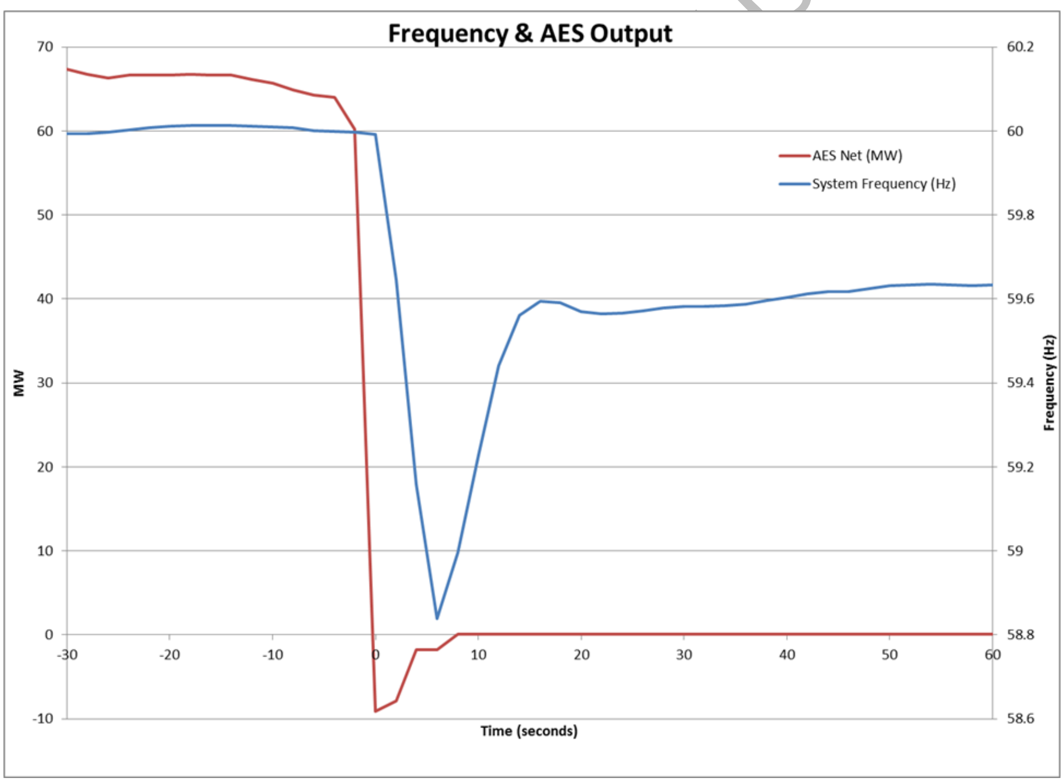

Figure 3. AES Output and Frequency Response

System Conditions Before AES Boiler Tripped

Table 3 shows the unit commitment and dispatch before to the AES boiler trip. About 33% of the system's firm generation was unavailable. (See Table 2 for the reasons these units were derated or unavailable.) The system was carrying approximately 209 MW of spinning reserve (excess spinning reserve of 25 MW). After the initial AES boiler trip, the spinning reserve was enough to cover the loss of 90 MW from Kalaeloa CT-1.

Unit	Gross Capacity	Derate	Available Gross Capacity	Available Net Capacity	Spinning Reserve
Kahe 1	86	–11	75	82	4
Kahe 2	86	—	86	76	10
Kahe 3	90	—	90	75	15
Kahe 4	89	–89	0	Not available	Not available
Kahe 5	142	–142	0	Tripped offline	Tripped offline
Kahe 6	142	–142	0	Not available	Not available
Waiau 3	49	—	49	25	24
Waiau 4	49	—	49	25	24
Waiau 5	57	—	57	25	32
Waiau 6	56	–21	35	24	11
Waiau 7	87	—	87	76	11
Waiau 8	90	—	90	48	42
Waiau 9	47	—	47	0	0
Waiau 10	44	—	44	8	36
CIP CT-1	113	—	113	0	0
AES	180	—	180	180	0
H-POWER	69	–11	58	58	0
Kalaeloa CT-1	104	–14	90	90	0
Kalaeloa CT-2	104	–104	0	0	0
KSEP (Tesoro)	1	—	—	1	—
Kawailoa & Kahuku	99	—	—	5	—
KS2 & KREP	10	—	—	8	—
Totals	1,794	534	1,150	806	209
Load	—	—	—	800	—

Table 3. Generating Capacity Before the AES Boiler Trip

While Kahe 1 was derated for fuel oil supply control instability, Power Supply operators did not block its governor, so the unit was able to provide full output on governor response. The derate might have been a dispatch limit. This fuel instability issue was resolved on January 16, 2015.

System Conditions Before the AES Turbine Tripped

Table 4 shows the unit commitment and dispatch before to the second AES boiler and its turbine tripped. AES was operating at 70 MW. We started Waiau 9 to replenish the system's spinning reserve. Spinning reserve was about 137 MW; excess spinning reserve was 57 MW. Waiau 9, however, had a control problem and was not able to provide its expected droop response. Thus, spinning reserve was actually about 100 MW. Still this was enough to cover the loss of Kalaeloa CT-1 at 90 MW.

The only remaining unit available for commitment was CIP CT-1 with a capacity of 113 MW.

Unit	Gross Capacity	Derate	Available Gross Capacity	Available Net Capacity	Spinning Reserve
Kahe 1	86	–11	75	83	3
Kahe 2	86	—	86	80	6
Kahe 3	90	—	90	86	4
Kahe 4	89	–89	0	Not available	Not available
Kahe 5	142	–142	0	Tripped offline	Tripped offline
Kahe 6	142	–142	0	Not available	Not available
Waiau 3	49	—	49	36	13
Waiau 4	49	—	49	35	14
Waiau 5	57	—	57	39	18
Waiau 6	56	–21	35	33	2
Waiau 7	87	—	87	83	4
Waiau 8	90	—	90	86	4
Waiau 9	47	—	47	6	41
Waiau 10	44	—	44	16	28
CIP CT-1	113	—	113	0	0
AES	180	—	180	65	0
H-POWER	69	–11	58	58	0
Kalaeloa CT-1	104	–14	90	90	0
Kalaeloa CT-2	104	–104	0	0	0
KSEP (Tesoro)	1	—	—	1	—
Kawailoa & Kahuku	99	—	—	4	—
KS2 & KREP	10	—	—	4	—
Totals	1,794	534	1,150	805	137
Load	—	—	—	800	—

Table 4. Generating Capacity Before the AES Turbine Trip

System Conditions After the AES Turbine Tripped

Table 5 shows the unit commitment and dispatch after AES fully tripped offline at 5:00 PM on January 12, 2015. At that point, AES was completely unavailable to meet evening peak. Because of control problems, Waiau 9 was also unavailable.

Only CIP CT-1 reserve of 64 MW remained with any substantial amount of generation. Spinning reserve was about 99 MW; excess spinning reserve was 9 MW. Load was about to increase to a projected 1,030 MW as evening peak started, thus the need for rolling outages.

Unit	Gross Capacity	Derate	Available Gross Capacity	Available Net Capacity	Spinning Reserve
Kahe 1	86	–11	75	77	9
Kahe 2	86	—	86	80	6
Kahe 3	90	—	90	83	7
Kahe 4	89	–89	0	Not available	Not available
Kahe 5	142	–142	0	Tripped offline	Tripped offline
Kahe 6	142	–142	0	Not available	Not available
Waiau 3	49	—	49	47	2
Waiau 4	49	—	49	45	4
Waiau 5	57	—	57	55	2
Waiau 6	56	–21	35	35	0
Waiau 7	87	—	87	85	2
Waiau 8	90	—	90	89	1
Waiau 9	47	—	47	45	2
Waiau 10	44	—	44	44	0
CIP CT-1	113	—	113	49	64
AES	180	—	180	0	0
H-POWER	69	–11	58	58	0
Kalaeloa CT-1	104	–14	90	90	0
Kalaeloa CT-2	104	–104	0	0	0
KSEP (Tesoro)	1	—	—	1	—
Kawailoa & Kahuku	99	—	—	4	—
KS2 & KREP	10	—	—	4	—
Totals	1,794	534	1,150	891	99
Load	—	—	—	875	—

Table 5. Generating Capacity After the AES Turbine Trip

Legacy Photovoltaic (PV) Generation

When system frequency dropped to 59.3 Hz following the AES boiler and turbine trip, a significant amount of legacy PV—between 25 MW and 30 MW—tripped offline because of their under-frequency protection settings. This loss of generation contributed to the contingency event. (A similar loss occurred during the previous AES trip on April 2, 2013 and June 9, 2014.)

We employed two methods to determine a amount of legacy PV lost during the contingency.

First Method: Aggregate Inertial Response

Immediately after the frequency reaches 59.3 Hz, we take the sum of the aggregate inertial response (the sum of the increase in generator MW output) from units running high-speed Tesla recordings. (Only Hawaiian Electric units have Tesla recorders that measure inertial response.)

We calculated an inertia ratio[4] by dividing the total inertia of all online generator units by the total inertia of the units with high-speed Tesla recordings. We then multiplied this inertia ration by the aggregate inertial response to determine the amount of Legacy PV generation that disconnected at frequency 59.3 Hz. From these calculations, we estimated that approximately 25–30MW of PV generation was lost.

[4] The inertia ratio = ∑ H-constant of online units with Tesla ÷ ∑ H-constant of all online units. For this event, the inertia ratio was 0.61.

Figure 4 shows the aggregate inertial response of the utility-owned units with Tesla recorders. We measured inertial response at 59.3 Hz to be 14.97 MW. Dividing this inertial response by the inertia ratio of 0.61 obtain the estimated 25 MW of Legacy PV that tripped offline.

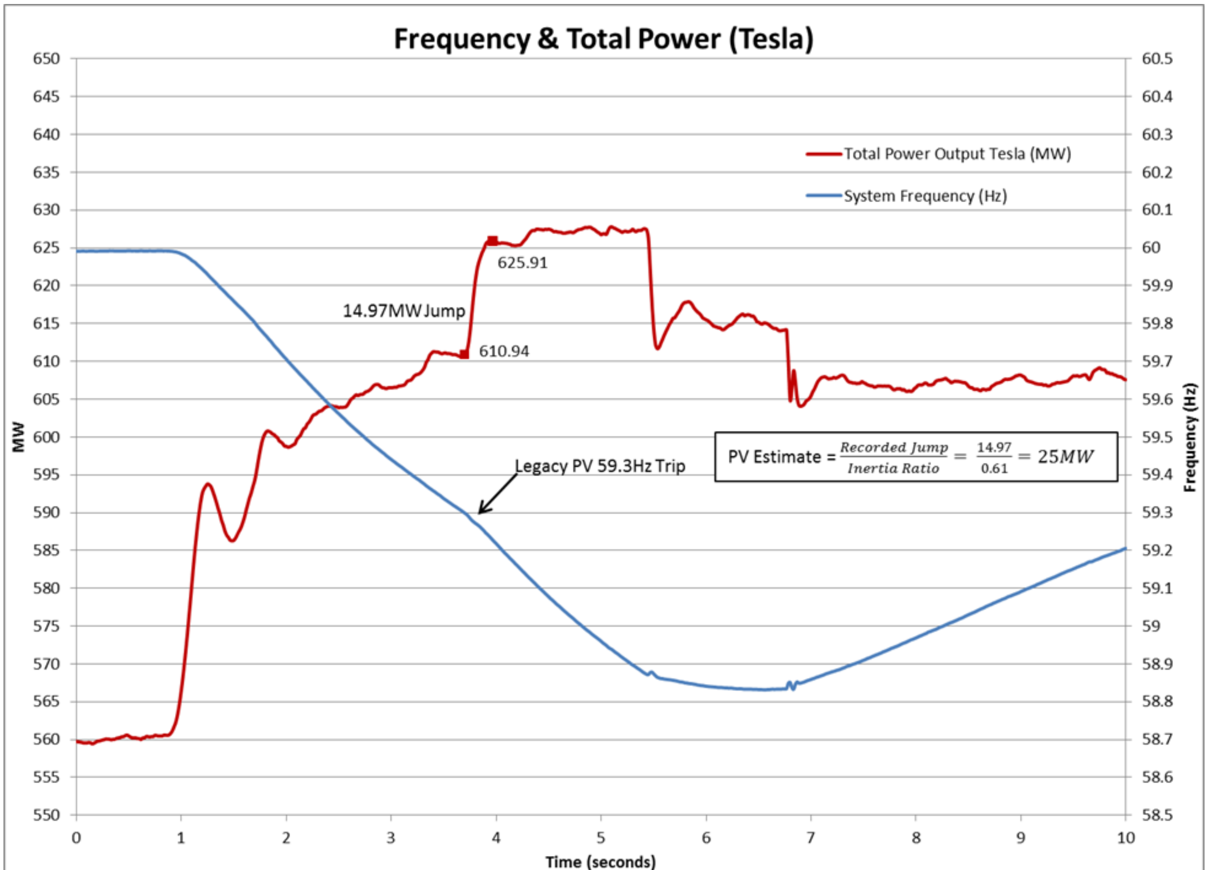

Figure 4. Estimate of Legacy PV Capacity Following the AES Trip Event

Second Method: Decrease in System Load

For the second method, we measure the decrease in system load five minutes after the system frequency initially decayed to 59.3 Hz. Five minutes is the time delay before Legacy PV inverters can reconnect to the system. Figure 5 shows a decrease of approximately 25 MW in system load of five minutes after legacy PV tripped offline.

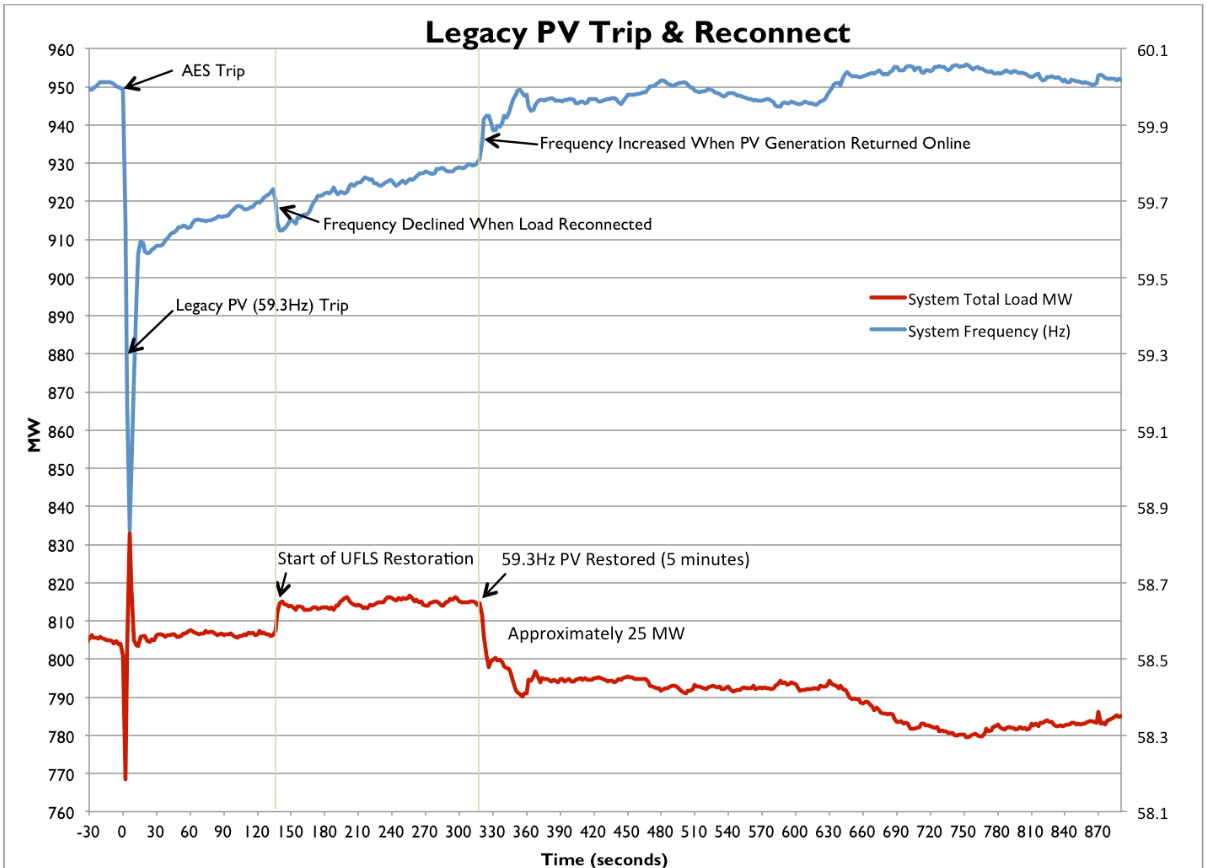

Figure 5. Estimate of Legacy PV Reconnected Following the AES Trip Event

Frequency and Load Following the Trip Event

Figure 6 shows how system load and frequency reacted for the 15 minutes following the full AES trip event. This figure simply expands upon the graph in Figure 5. Notice, however, that in Figure 6, the red line represents frequency while the blue line represents load.

As the system stabilizes, frequency returns to hover around 60.0 Hz after about 5 minutes. At that time, DG-PV is restored and system load by 25 MW over the next 30 seconds.

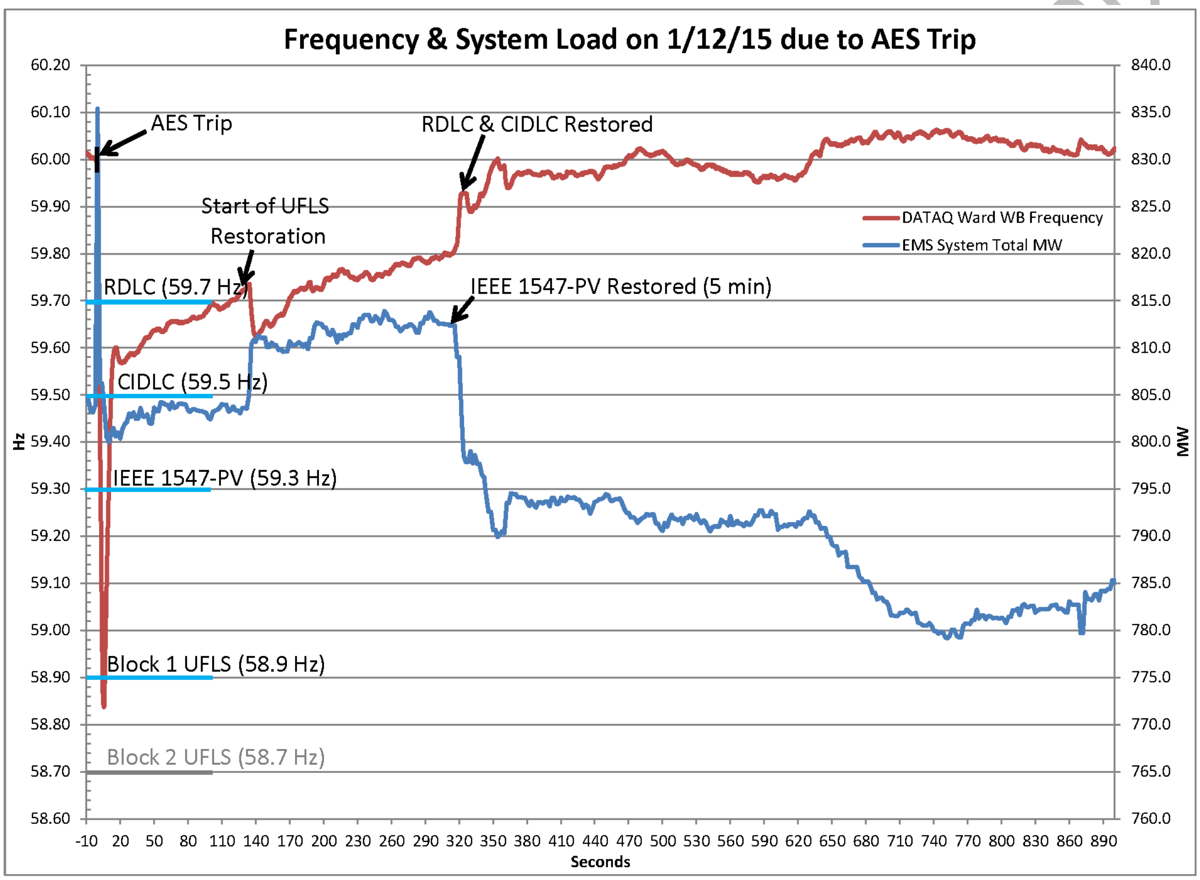

Figure 6. Frequency and System Load on 12 January 2015 Due to the AES trip

Amount of Under Frequency Load Shed

When system frequency dropped to 58.9 Hz following the trip event, an under frequency load shed (UFLS) Block 1 was automatically dispatch. Frequency reached a nadir of 58.837 Hz, but quickly recovered so no other load blocks were shed.

Table 6 shows the design and expected loads for UFLS Block 1.

Assuming a unity power factor for the three-phase MVA, the measured load was approximately 25 MW which falls within the daytime minimum and peak values. All of Block 1 circuit breakers operated in 5 cycles or less. As designed, all Block 1 relays automatically returned to normal when frequency was restored. In addition, all Block 1 circuit breakers reclosed as designed (except for Waimano #5 CB1387 because debris prevented the circuit from reclosing).

Design Load Shed Amount Block I	Daytime Minimum Net Load Shed	Daytime Peak Net Load Shed	Measure Load Shed 3-Phase MVA Load
46 MW	20.87 MW	37.73 MW	30.53 MW

Table 6. Under-Frequency Load Shed Design[5]

While the UFLS Block 1 operated as expected to arrest the decay in system frequency, a 70 MW unit trip should not require UFLS to stabilize system frequency.

[5] The daytime minimum and peak net load shed amounts are based on the 2013 system data and historical measured load shed: Net am July 29, 2013, 1,037.48 MW; daytime minimum net April 1, 2013, 525.28 MW. The load is based on SEL data assuming a power factor for the 3Φ MVA load, and SEL relays assuming all load shed relays in Block I operated as designed.

Generator Unit Response

The system generation units responded during the AES ramp down and after the AES trip event. The following figures show how all units responded during the ramp down, and now all units and groups of units responded to the AES trip event.

Response of All Unit to AES Ramp Down

Figure 7 shows the response of all available units during the ramp down event that occurred after the first AES boiler tripped and the unit struggled to stabilize before AES completely tripped offline.

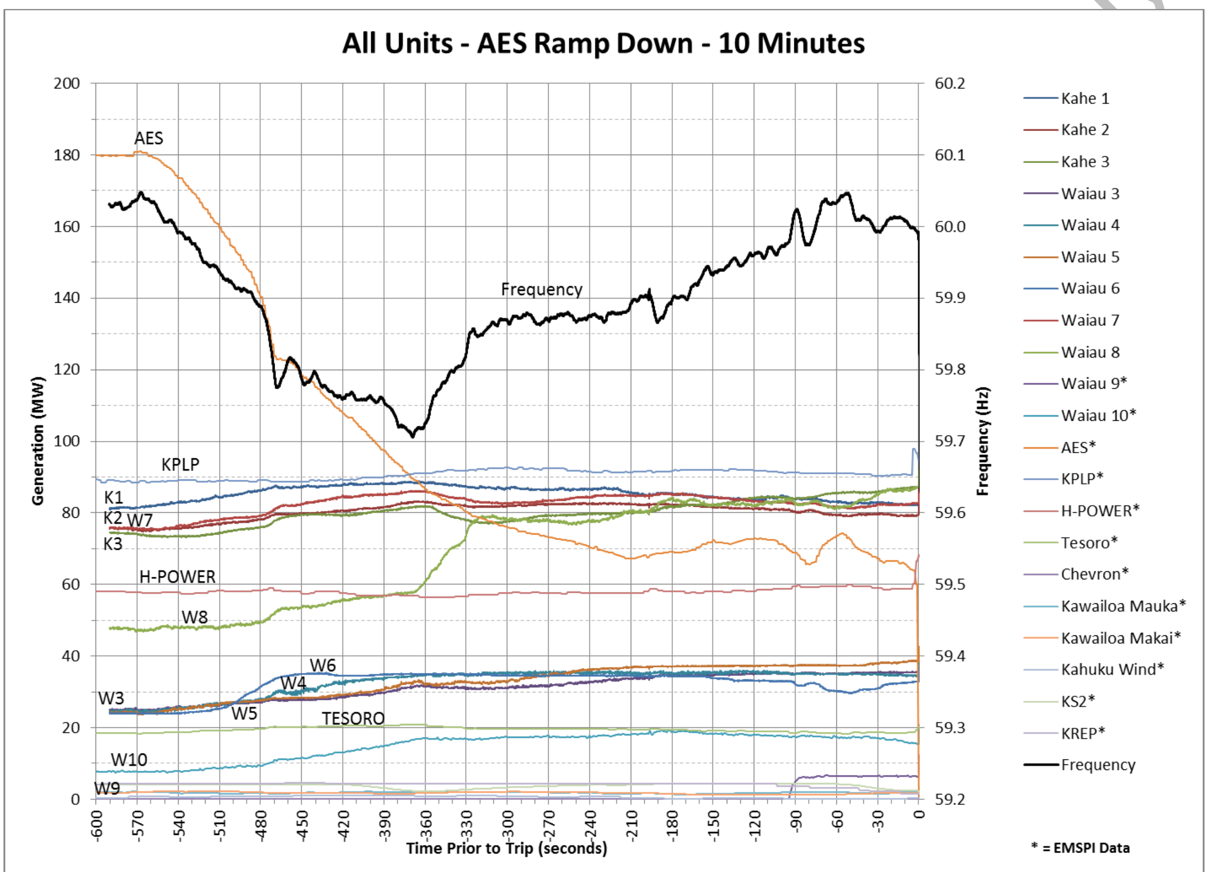

Figure 7. Response of All Generation Units During the AES Ramp Down

Response of All Unit to AES Trip Event

Figure 8 shows the response of all available units after AES tripped offline. Except for Waiau 9, all units responded as expected.

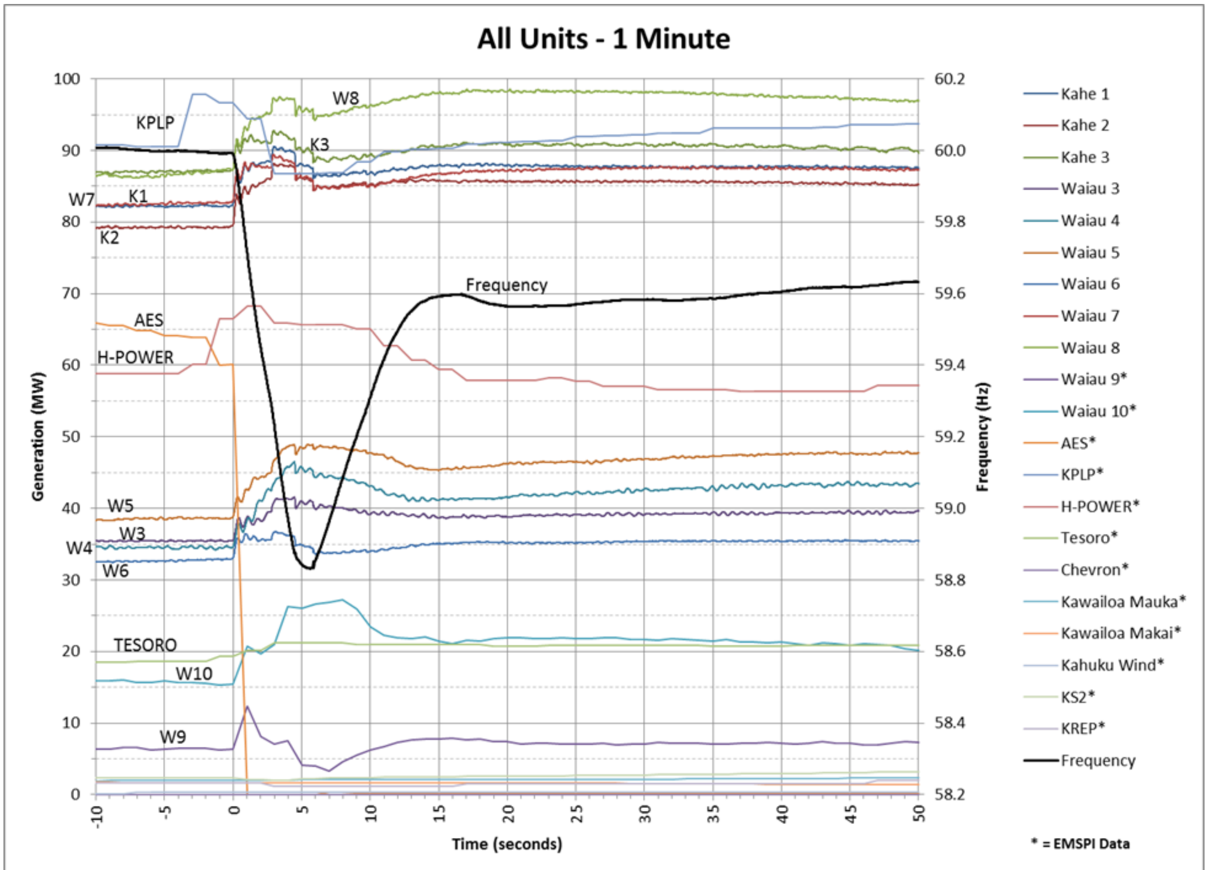

Figure 8. Response of All Generator Units at One Minute of AES Trip Event

Response of Kahe Units to AES Trip Event

Figure 9 shows how three Kahe units responded to the drop in frequency following the AES trip event. Operators dispatched Kahe 1 at 82 MW, Kahe 2 at 79 MW, and Kahe 3 at 87 MW. At 5% governor droop response, the governor valves opened to 100% to deliver full output. All three Kahe units performed as expected.

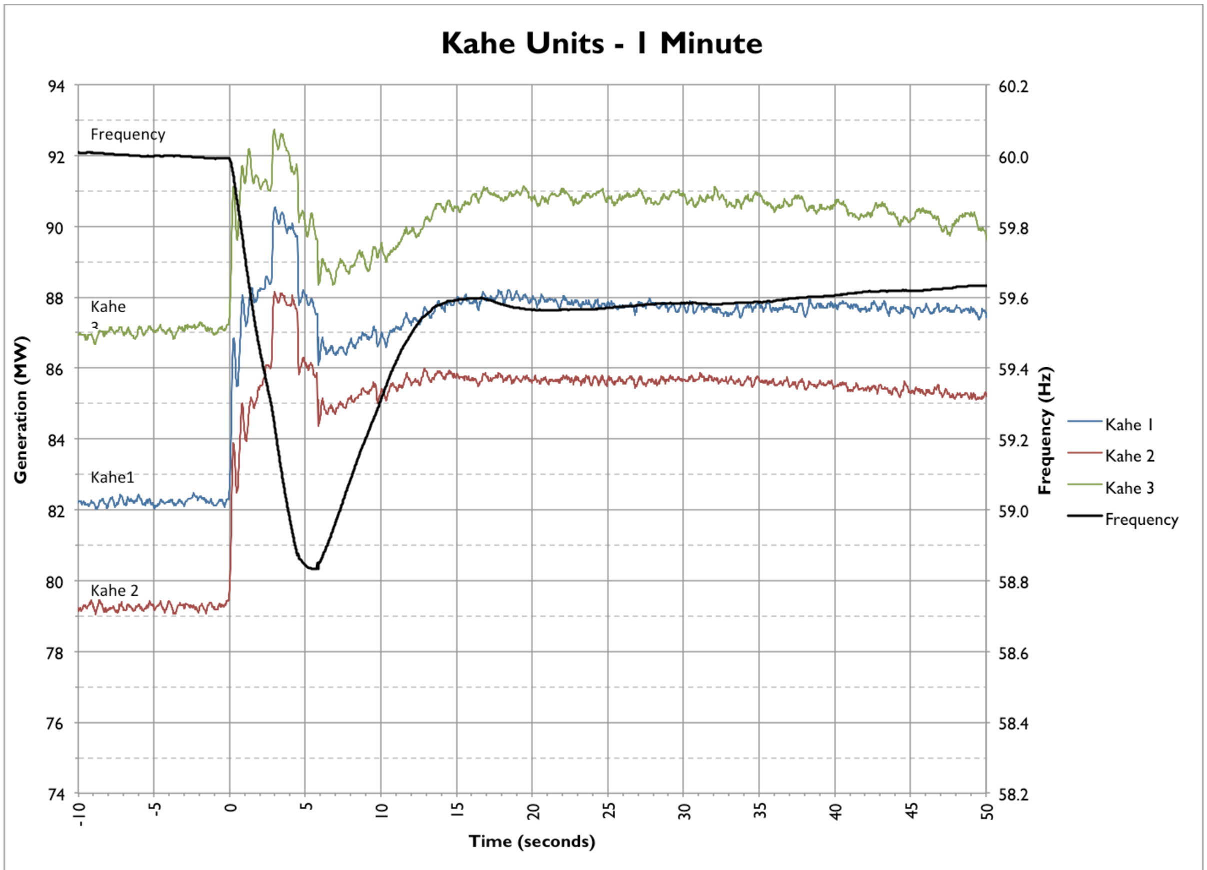

Figure 9. Response of Kahe Units at One Minute of AES Trip Event

Response of Waiau Units to AES Trip Event

Figure 10 shows how we dispatched the Waiau units to respond to the drop in frequency following the AES trip event. Operators dispatched Waiau 3 and Waiau 4 at 35 MW; Waiau 5 at 38 MW; Waiau 7 at 82 MW; Waiau 8 at 87 MW; and Waiau 10 at 16 MW.

The governor value for Waiau 6 was blocked at 35 MW because of a boiler hot spot. We dispatched Waiau 9 at 6 MW, however the unit was unable to sustain its output from inertial response because of a control logic problem, causing its output to fall below the allowable minimum load stipulated in the covered source permit (CSP). To prevent a CSP violation, the Waiau 9 control logic initiated an automatic shutdown; the unit was offline within ten minutes. (The logic problem has since been corrected.) The governor valve for Waiau 6 was blocked at 35 MW due to a boiler hot spot.

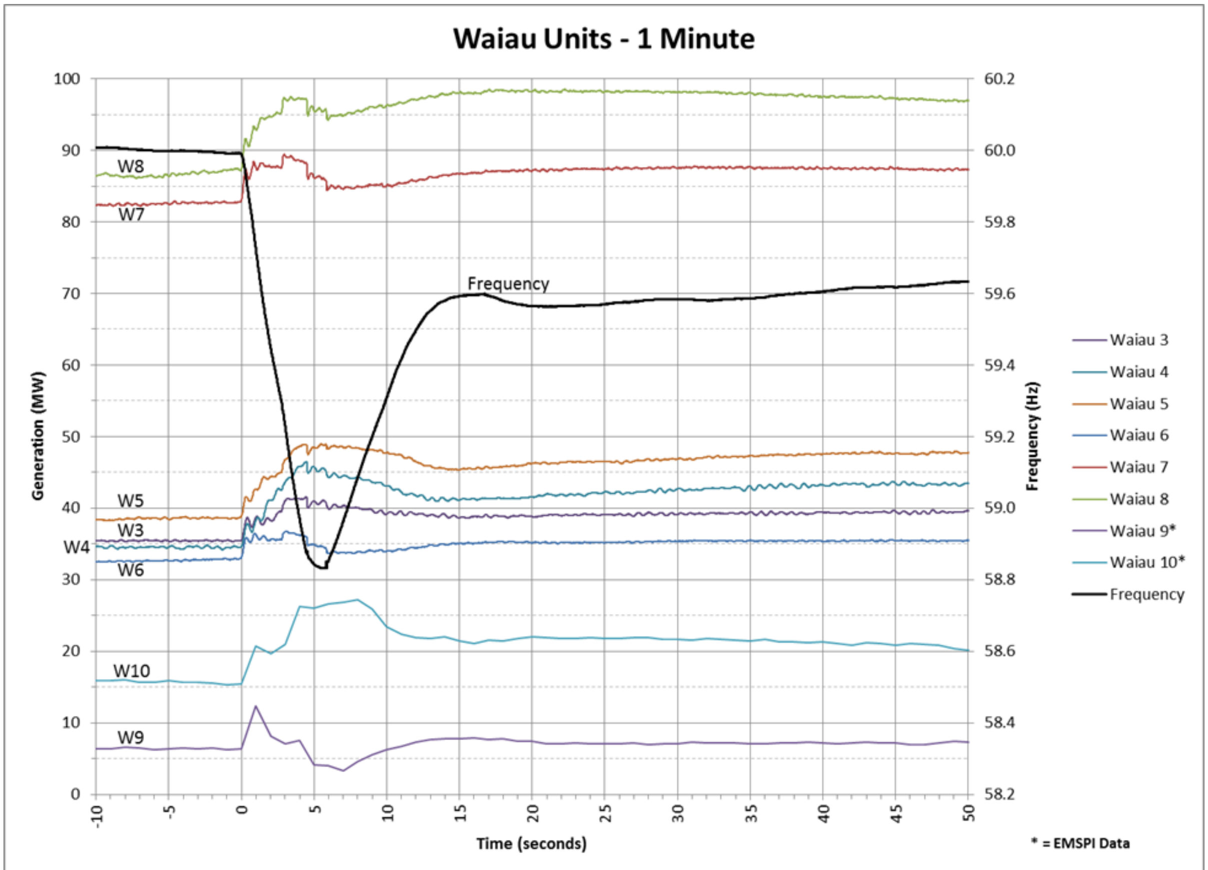

Figure 10.Response of Waiau Units at One Minute of AES Trip Event

Response of IPP Units to AES Trip Event

Figure 11 shows how the IPP united responded to the drop in frequency following the AES trip event. KPLP was operating at only 90 MW [6], less than half of its full rating at 208 MW. H-POWER was also derated because of insufficient fuel. Both Kalaeloa CT-1 and H-POWER provided inertial response, but neither was able to sustain its initial output.

[6] The Kalaeloa (KPLP) combustion turbine (CT-1) was generating 76 MW while its steam turbine (ST) was generating 14 MW.

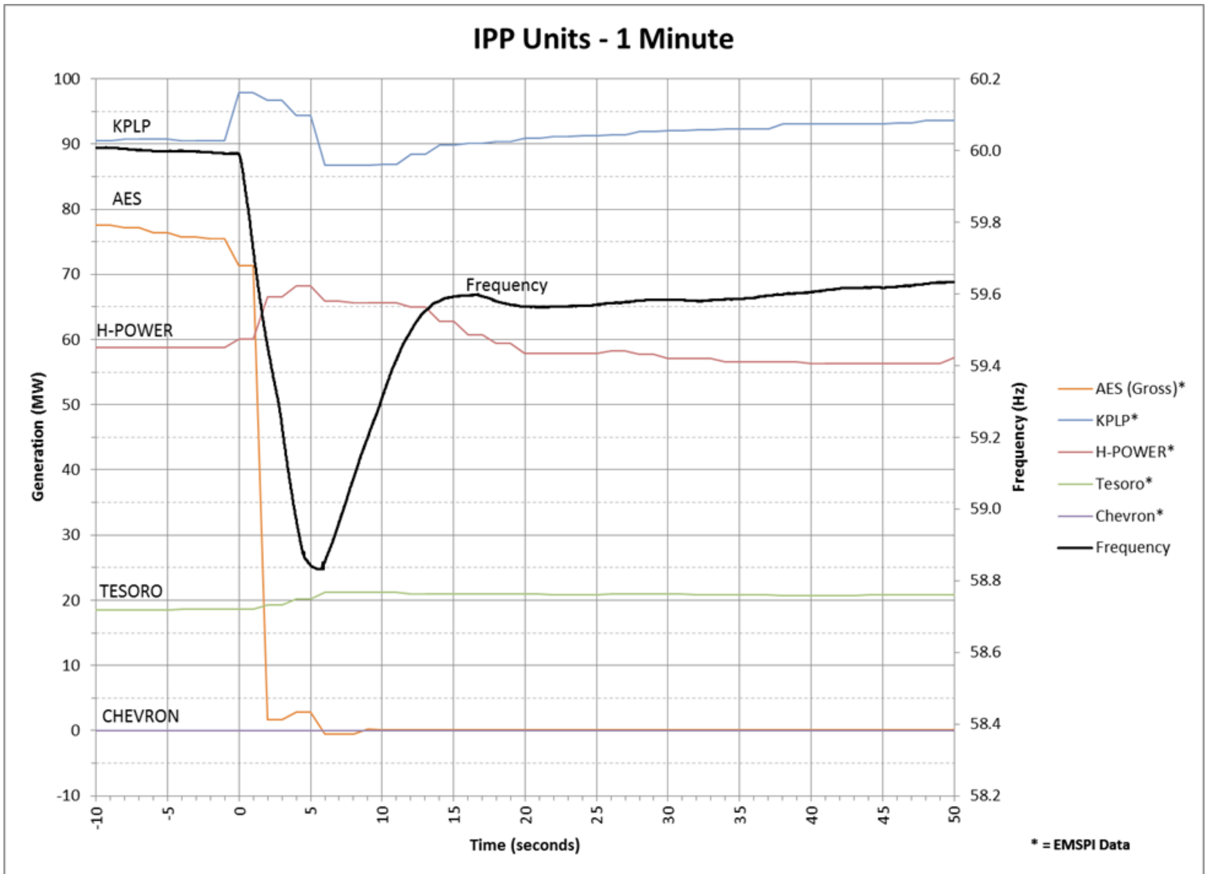

Figure 11.Response of IPP Units at One Minute of AES Trip Event

Response of Central Renewable Units to AES Trip Event

Figure 12 shows how the central renewable units responded to the drop in frequency following the AES trip event. Output from Kalaeloa Solar Two (KS2) began increasing within 5 seconds of the trip event; output from Kalaeloa Renewable Energy Park (KREP) began increasing 45 seconds after the trip event. System operators did not curtail this generation. Neither wind units— Kawailoa and Kahuku—provided significant response, mainly due to their low output at the time of the trip event.

Generation from both units, however, decreases as frequency decays which indicates that neither meet frequency ride-through requirements. We must investigate this minimal response to system frequency if we are to rely on these units for contingency reserve for future trip events.

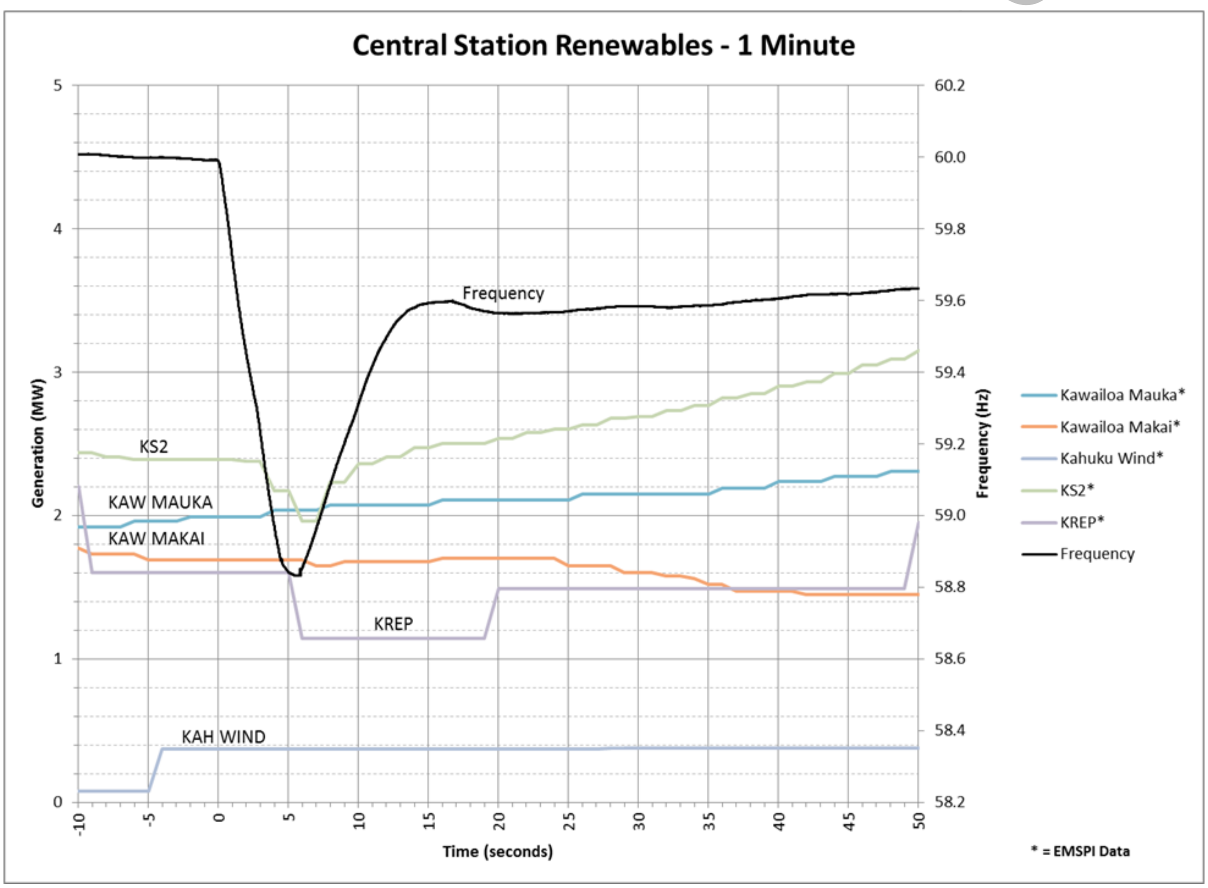

Figure 12. Response of Central Renewable Units at One Minute of AES Trip Event

FREQUENCY RESPONSE SIMULATIONS

We simulated system frequency response using a dynamic model that was tuned and validated against Tesla data. We determined the unit commitment, unit dispatch, and system conditions for the simulation using actual data six seconds before the AES trip event which assumed 25 MW of Legacy PV. We did not perform simulations for the boiler trip or ramp-down event.

Caveats to the Analysis

We conducted these simulations using PSSE (Power System Simulator for Engineering) Version 33, a software program used for electrical transmission networks. We conducted a number of simulations and validated the results against Tesla and OSI PI data to properly tune the dynamic models. While our simulated results attempt to recreate actual system events as accurately as possible, there is a level of uncertainty that is inherent to any modeling analysis.

Simulated Frequency Response

Figure 13 simulates frequency response. The blue plot was tuned to match the black plot from Tesla data. The red plot simulates output from AES. The simulated frequency nadir is identical to actual data, but the settling frequency is slightly lower than recorded. We also duplicated the rate of change of frequency (RoCoF) and the frequency nadir, as required for these sensitivity analyses.

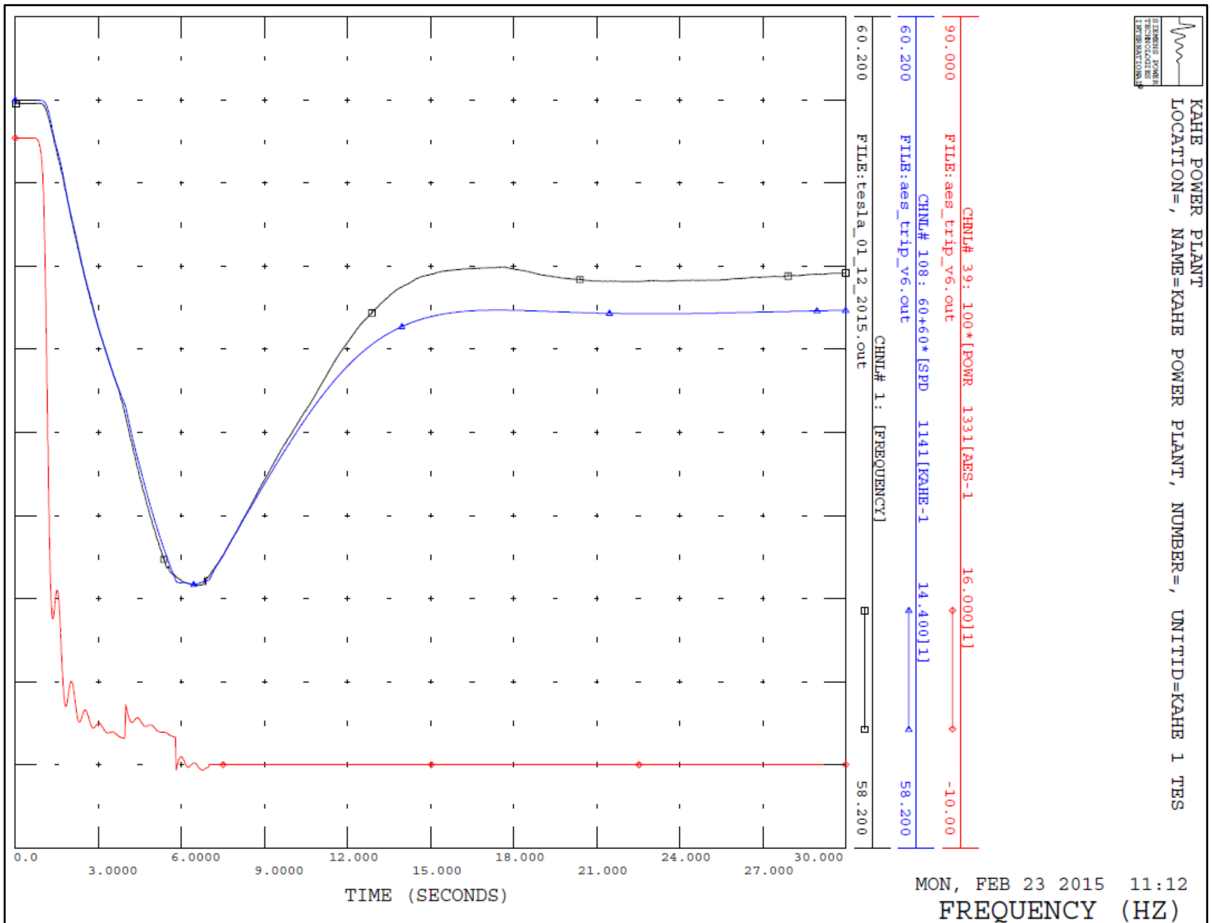

Figure 13. Simulated Frequency Response

Sensitivity Analysis—No Legacy PV

Figure 14 simulates the impact of Legacy PV. The red plot shows that if Legacy PV didn't trip offline at 59.3 Hz, the UFLS would have been avoided.

The red plot simulates system frequency without the impact of Legacy PV. The loss of additional generation after a unit trip further aggravates the severity of the total loss of generation contingency. Our analysis of generator data clearly shows droop response at 59.3 Hz as a result of Legacy PV. If Legacy PV didn't trip offline, the system frequency nadir would have remained above 59.0 Hz, thus preventing the block of UFLS.

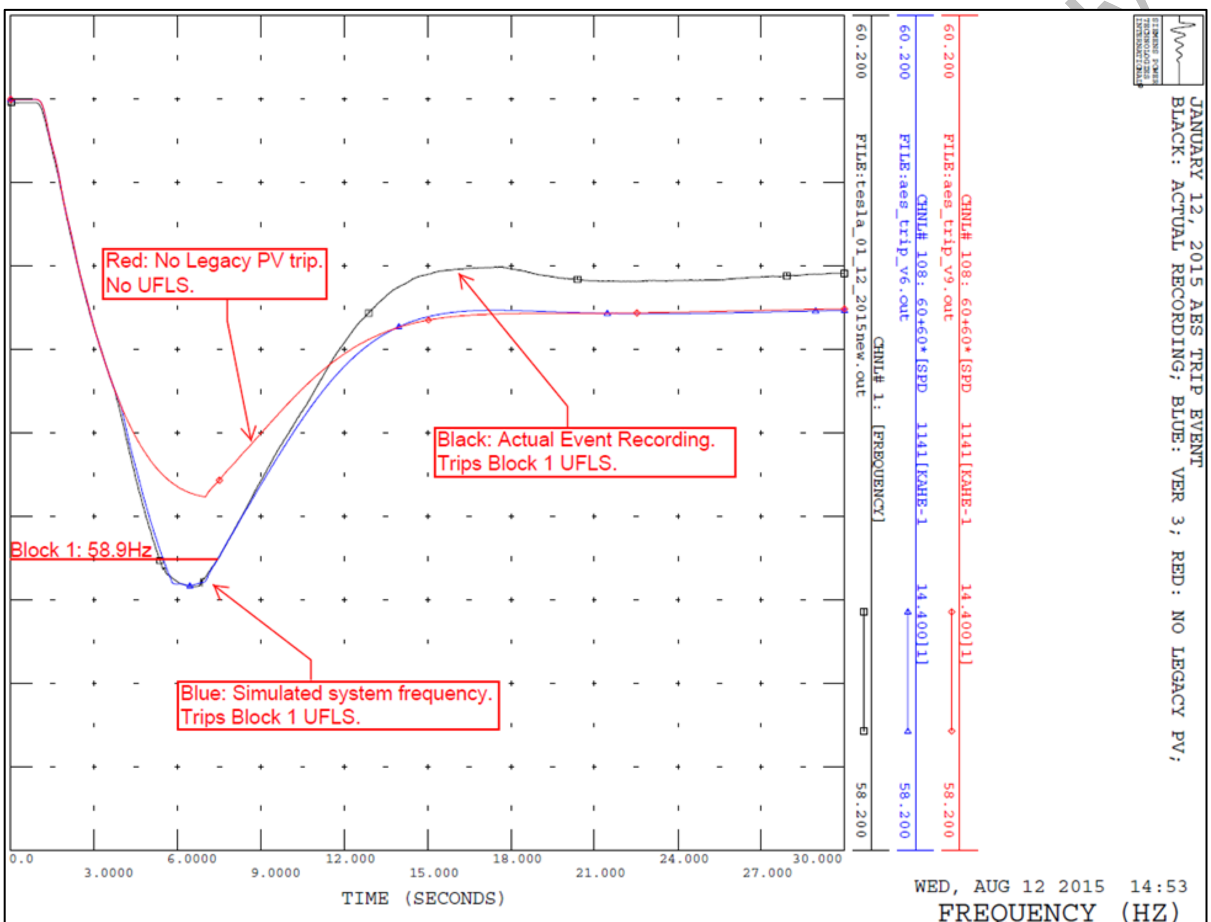

Figure 14. Simulated Frequency Response: No Legacy PV

Sensitivity Analysis—Waiau 9 Logic Correction

Figure 15 simulates the frequency response if Waiau 9 was able to sustain its output from inertial response. The red plot shows a slight improvement in frequency response, but the frequency nadir still dips below the Block 1 trip setting of 58.9 Hz. Thus, even if Waiau 9 was available, the system still would have experienced one block of UFLS necessary to stabilize system frequency.

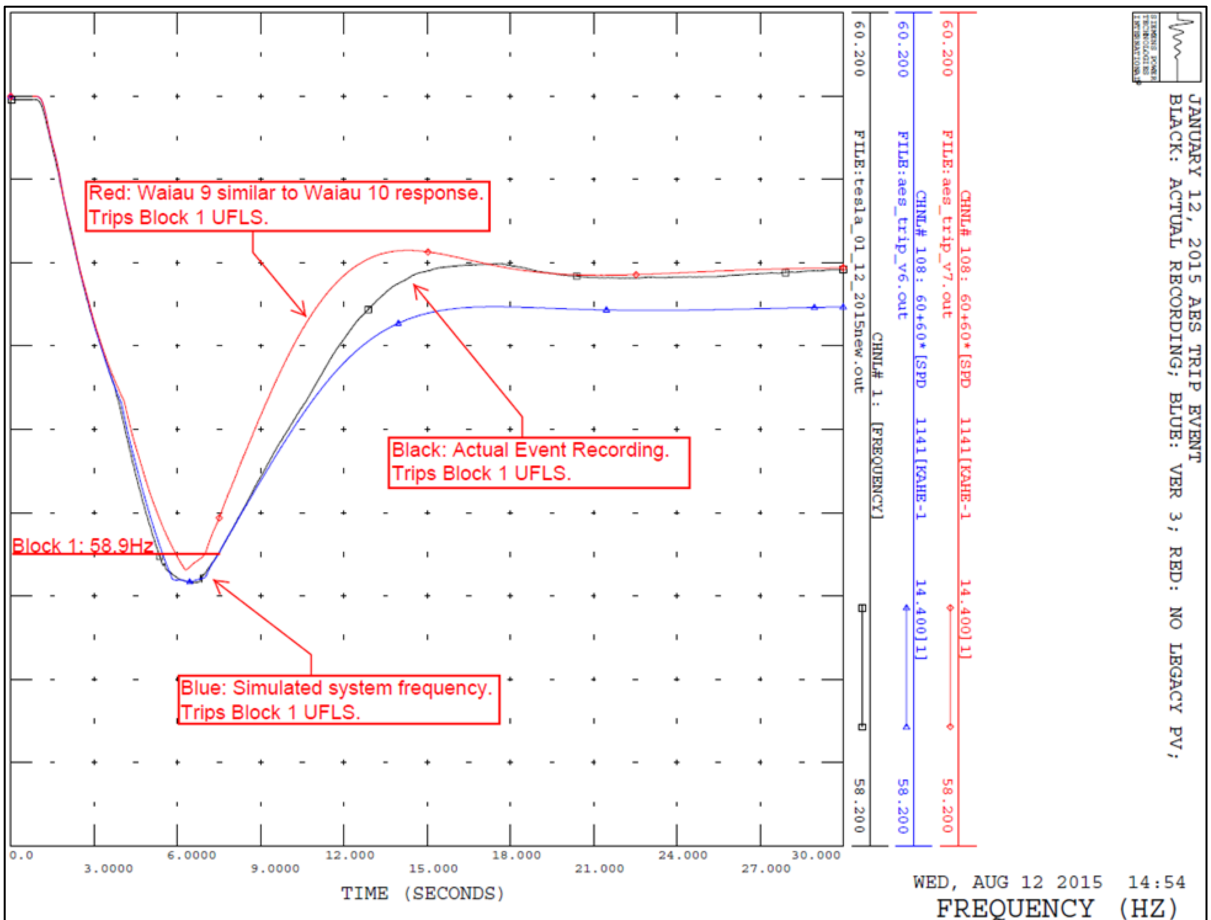

Figure 15. Simulated Frequency Response: Corrected Logic on Waiau 9

Sensitivity Analysis—Increase System Inertia

Figure 16 simulates system frequency if operators had dispatched CIP CT-1 instead of Waiau 9. The red plot shows that the added inertia and contingency reserves provided by CIP CT-1 would have avoided the block of UFLS to stabilize system frequency.

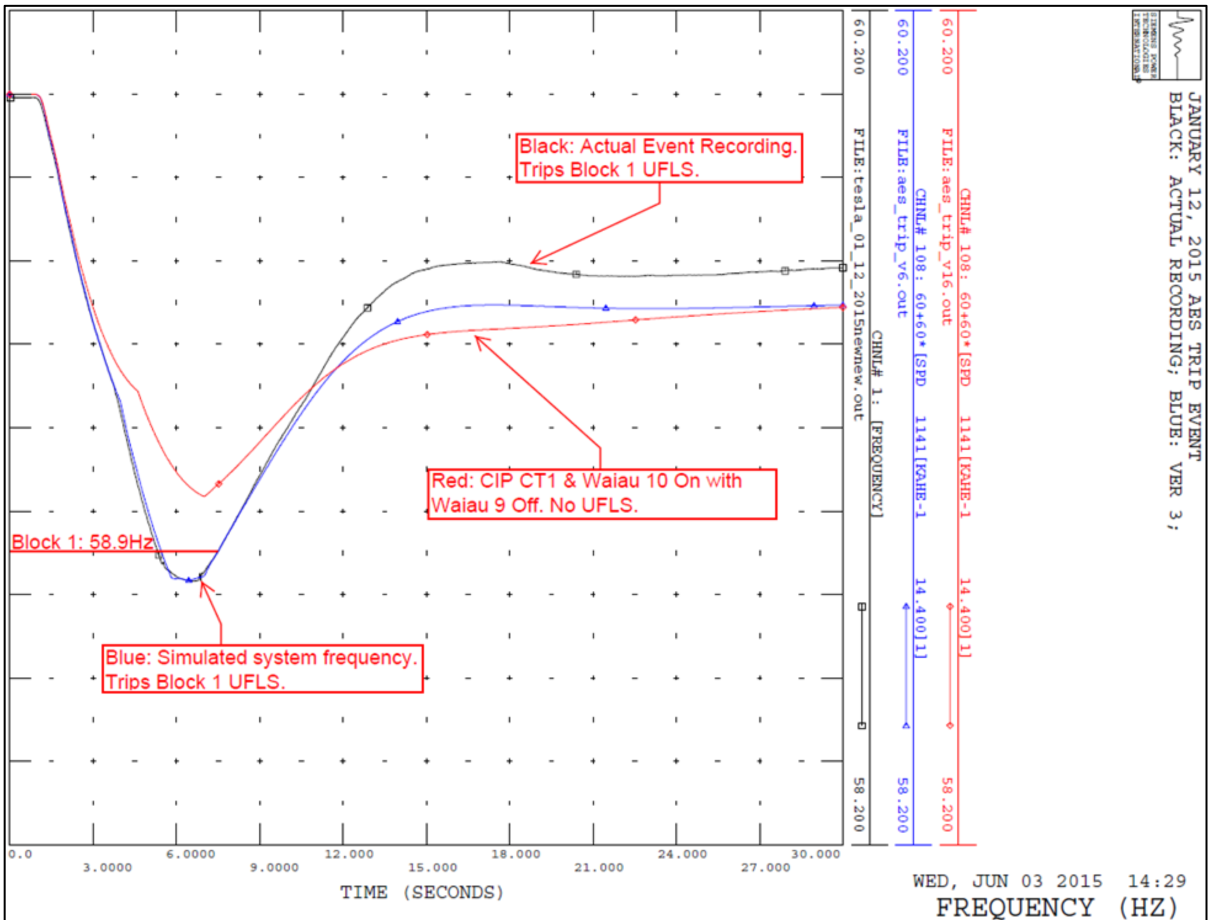

Figure 16. Simulated Frequency Response: CIP CT-1 in Lieu of Waiau 9

Sensitivity Analysis—130 MW BESS

Figure 17 simulates system frequency response with a 130 MW of BESS in droop control. The simulation separates the BESS into three locations (consistent with the actual project): the CEIP, Halawa, and Ewa Nui substations. The inertial response from the BESS raises the frequency nadir above the 59.3 Hz frequency threshold. Thus, Legacy PV would not have tripped offline, which (as shown in "Sensitivity Analysis—No Legacy PV") would have avoided the block of UFLS to stabilize system frequency.

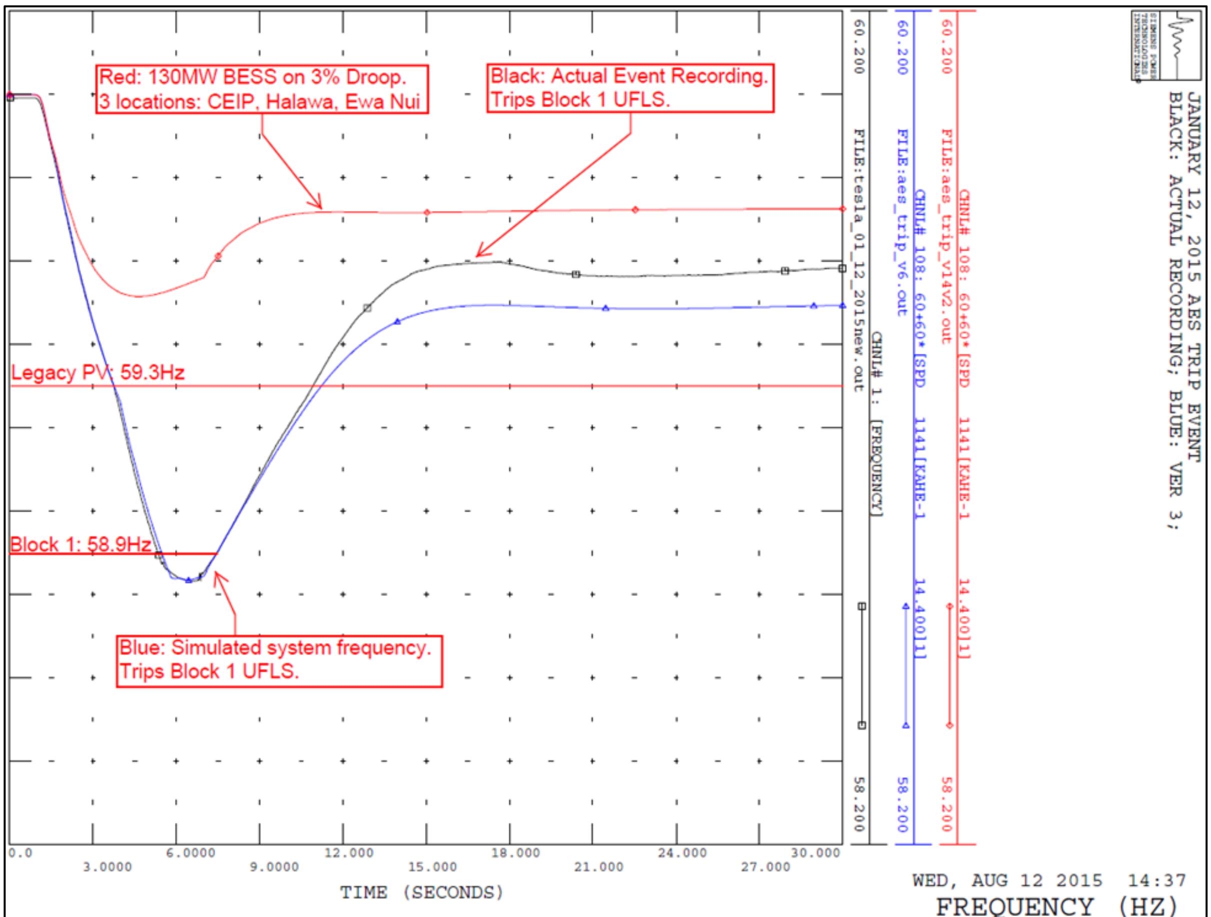

Figure 17. Simulated Frequency Response: BESS Sensitivity

GENERATION MIX FOR JANUARY 12

Figure 18 depicts the generation mix for January 12, 2015, and shows the generation response to the afternoon AES trip event and the evening rolling outages.

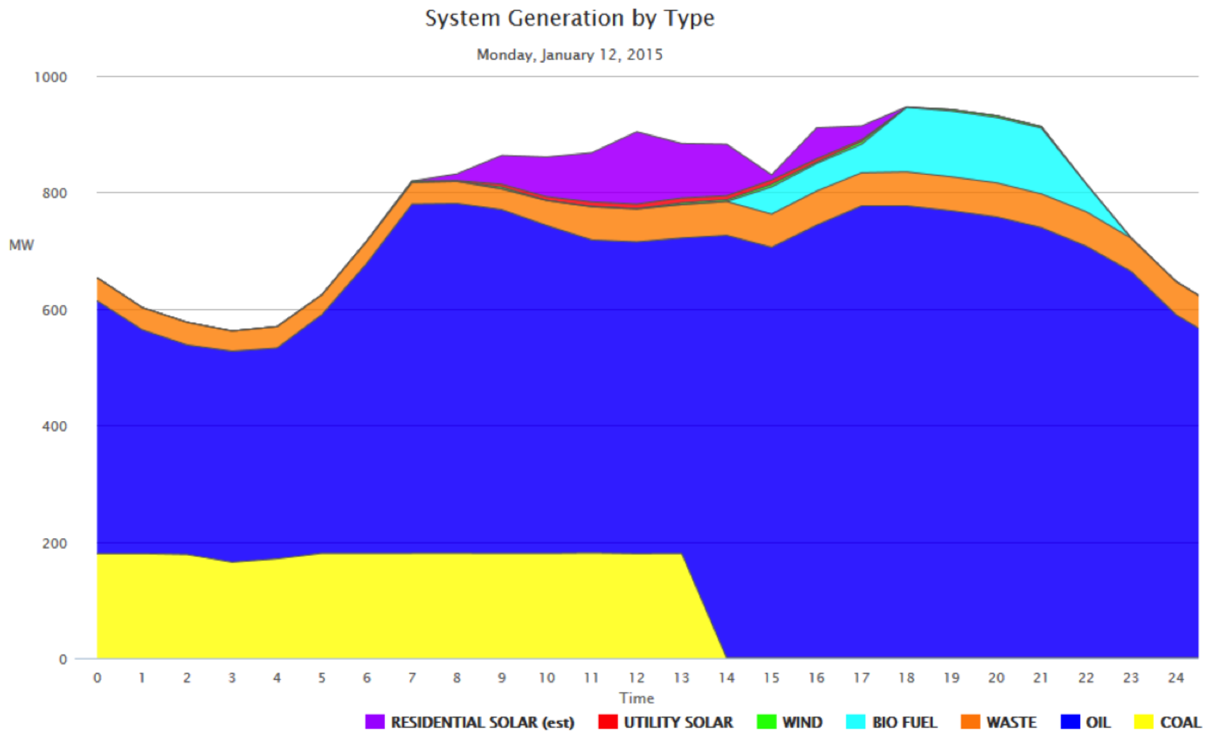

Figure 18. Generation Mix for January 12, 2015

AES (yellow) begins to ramp down and trip offline early afternoon, replaced by firm generation from Kahe and Waiau units (blue). Notice how all PV (purple and red) was offline by 6:00 PM. H-POWER (orange) increased its output to respond to the trip event, then held that generation amount throughout the remainder of the day. CIP CT-1 (light blue) was dispatched early afternoon after Waiau 9 failed to sustain its output, and increased its output during evening peak. Virtually no wind (green) was available.

The maximum generation during evening peak was about 950 MW.

COMPARISON OF THREE AES TRIP EVENTS

Besides the 12 January 2015 trip event, the AES generator tripped on 2 April 2013 and then again on 9 June 2014.

The April 2, 2013 AES Trip Event

The failure of a Linear Differential Variable Transducer caused the April 2, 2013 AES trip, which effectively lost 208 MW of generation. (The additional load loss was attributed to generator motoring, that has since been resolved by reducing the time delay for the reverse power relay from 2.5 seconds to 12 cycles.) Approximately 61 MW of Legacy PV tripped at 59.3 Hz, increasing the contingency magnitude to 269 MW. The total generation loss represented 33% of system load.

Three UFLS blocks automatically dispatched to stabilize system frequency despite the 308 MW of spinning reserve.

We implemented a handful of system improvements after investigating the 2013 AES trip event. We:

- Changed the under-frequency relay setting to trip AES auxiliary loads from 58.7 Hz to 59.5 Hz so that the auxiliary loads would kick in sooner after a unit trip.
- Replaced the speed-error cards on Kahe 5 and Kahe 6 to improve droop response.
- Reduced Kalaeloa's deadband from ±0.5 Hz to ±0.25 Hz.
- Reduced the AES primary reverse power relay from 2.5 seconds to 15 cycles to better enable its time delay. (This system improvement, however, did not play a role in the 12 January 2015 trip event.)

The June 9, 2014 AES Trip Event

The faulty operation of an under-frequency relay caused the June 9, 2014 AES trip, which resulted in a turbine trip and the effective loss of 198 MW. Approximately 50 MW of Legacy PV tripped at 59.3 Hz, increasing the contingency magnitude to 248 MW. The total generation loss represented 30% of system load. Despite carrying 310 MW of spinning reserve, three blocks of UFLS automatically dispatched to stabilize system frequency. A second under-frequency event caused Kicker Block 1 to trip.

The January 12, 2015 AES Trip Event

A boiler trip caused an AES ramp down to about 70 MW over about five minutes. The unit stabilized for a couple of minutes, but then the second boiler tripped resulting in a turbine trip causing AES to lose all 180 MW of generation. Approximately 25 MW of

Legacy PV tripped at 59.3 Hz, increasing the contingency magnitude to 205 MW. The total generation loss represented 17% of system load. Despite carrying 143 MW of spinning reserve, one block of UFLS automatically dispatched to stabilize system frequency.

Figure 19 compares the frequency response for these three AES events.

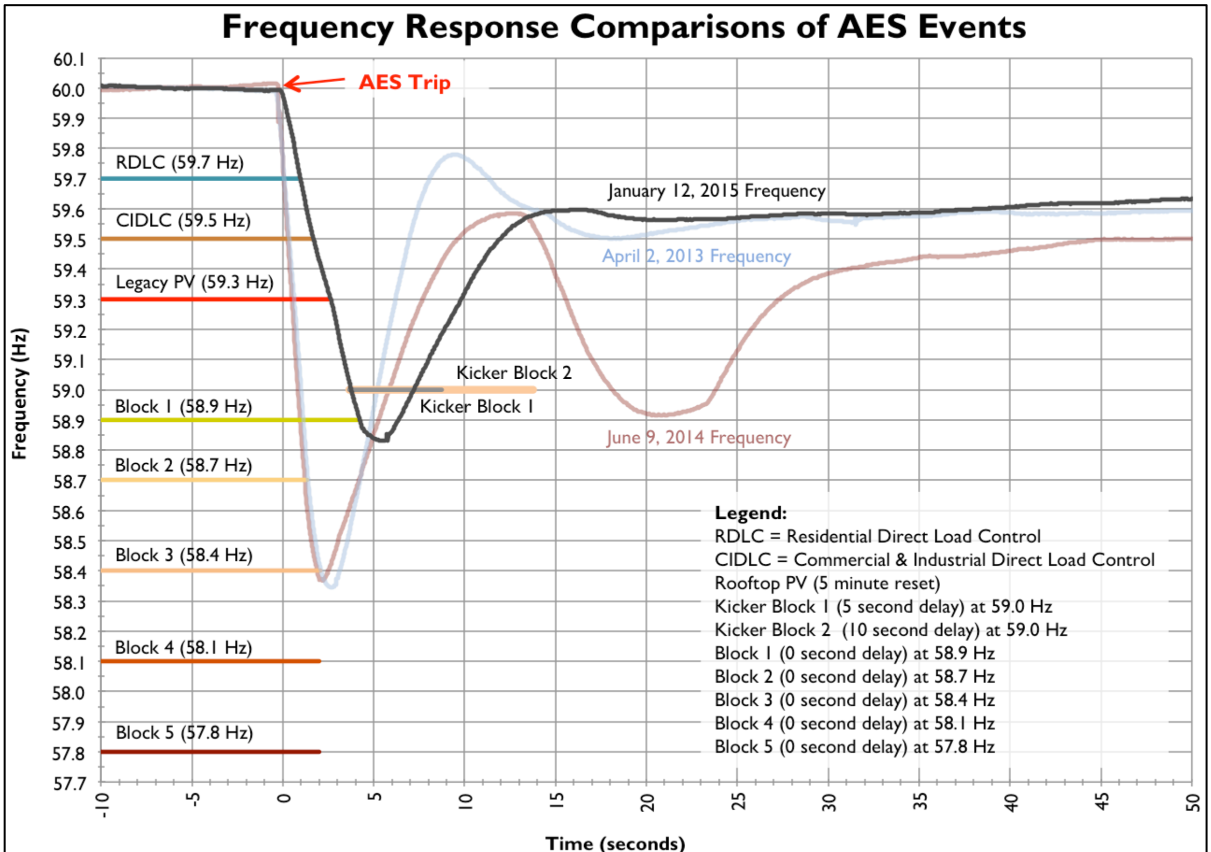

Figure 19. Frequency Response Comparisons of Three AES Events

Data Comparison of Three AES Trip Events

Table 7 compares data from those two events to the two events that occurred on 12 January 2015. Ultimately, this comparison shows the similarity among the four events.

Event Description	2 April 2013, 10:31 AM Event	9 June 2014, 9:49 AM Event	12 January 2015, 1:52 PM Event
System Load	800 MW	830 MW	800 MW
Generator Units Online	K1, K2, K3, K4, K5, K6, W6, W7, AES, HP, KPLP	K1, K3, K4, K5, K6, W7, W8, AES, HP, KPLP	K1, K2, K3, W3, W4, W5, W6, W7, W8, W9, W10, AES, HP, ½ KPLP
Total System Inertia	60.69	62.39	58.36
AES Gross Generation Loss	208 MW	198 MW	180 MW *
Excess Spinning Reserve	128 MW	130 MW	57 MW
Excess Quick Load Pickup	74 MW	50 MW	57 MW
Estimated PV Tripped at 59.3 Hz	61 MW	50 MW	25 MW
Frequency Nadir	58.35 Hz	58.36 Hz	58.837 Hz
Number of UFLS Blocks Shed	Blocks 1–3	Blocks 1–3 and Kicker Block 1†	Block 1
UFLS MW Shed	108 MW	96 MW and 13.5 MW	30 MW
Number of Customers Affected	79,000	86,510	20,325

* Two events occurred. First, a boiler trip lost 111 MW, then a turbine trip lost the remaining 60 MW plus 9 MW of auxiliary load.

† A circuit in the Kicker Block (Block 5) tripped, causing additional load shed.

Table 7. Data Comparison of Three AES Trip Events

For all three AES contingencies, we were carrying enough spinning reserve to cover the combined losses from AES and Legacy PV. Nonetheless, UFLS operated to stabilize system frequency.

The frequency response for the 2013 and 2014 contingency events shows a higher rate of change of frequency (total system inertia), which resulting in a lower frequency nadir. The high percentage of generation lost in each contingency (33% and 30% of total system generation) caused these high rate of change of frequencies. As a result, traditional primary reserves (like droop response) cannot arrest the decay of system frequency decay, thus UFLS must operate to stabilize system frequency.

CONCLUSIONS

The AES Hawai'i generator has now tripped offline in each of the last three years. (AES tripped offline again a few months after this year's contingency.) This year's AES trip event started with one of its boilers tripping before the entire unit tripped offline, which happened over a period of five minutes. This delay gave our system operators enough time to dispatch Waiau 9, thus limiting the UFLS to one block from only 2 to 6 minutes (compared to multiple blocks in the previous two trip events).

All three trip events carried sufficient spinning reserve, yet UFLS was still necessary to stabilize system frequency. Increasing amounts of DG-PV reduce system load, displace synchronous generation, and reduce system inertia, compromising system stability. Legacy PV disconnecting at 59.3 Hz increases the magnitude of the contingency, thus further compromising system stability. This larger contingency then results in a higher rate of change of frequency, making traditional governor droop response ineffective in arresting system frequency.

3. Internal and External Communication

On January 12, 2015, within minutes of the trip event—approximately 1:55 PM—personnel from System Operations notified Corporate Communication staff about the AES unit tripping offline, the load shedding, and the resultant brief outages. Immediately before that phone call, the Energy Management System (EMS) automatically informed us (by text messages an emails) of the trip event and resultant brief outages.

By this time, we had already begun to receive phone calls from the media about the outages. We told them about the trip, about the outages, and about the efforts to restore power.

Between 2:00–2:30 PM, System Operations notified us about the decision that rolling outages would be necessary that evening. They also told us the neighborhoods that would experience the outages and the approximate times of those outages.

System Operations and Corporate Communication have a close relationship. Over the course of the afternoon of January 12, 2015 and during the next two days, we spoke often with them to garner the most recent update of the evolving events surrounding the trip event. We then used this information as a basis for our news releases, press conference, social media posts, and conversations with news media.

COMMUNICATION STATEGY AND THE INCIDENT MANAGEMENT TEAM (IMT)

Our internal Incident Management Team (IMT), quickly organized, created and implemented a plan to communicate information about the event—a plan that remained flexible throughout the day as more and more information emerged.

After being informed about the trip event, Corporate Communication and Online Communication staff began setting up an Incident Management Team (IMT) to handle both internal and external communication about the trip event. The team was made up of the following personnel:

Lynne Unemori	Public Information Officer (PIO)
Barbara Heckathorn	Assistant PIO–Incident Commander
Darren Pai	Media Relations Unit Leader
Teri Theuriet	Employee Communication Unit Leader
Donna Mun	Online and Social Media Unit Leader

The IMT devised a strategy for communicating information about the event. As the afternoon and evening progressed, our frequent contact with System Operations kept us abreast of the latest developments in the trip event, the immediate brief outage, the operational status of the tripped units (both AES and Kahe 5), and the rolling outages expected for that evening's peak demand period.

The information obtained from System Operations formed the substance of our internal and external communication for the rest of the day, and over the next two days. Our internal audience includes all Hawaiian Electric employees (including key personnel such as our executive team) and our Key Accounts department; our external audience focuses on the news media, key stakeholders, and our customers.

News releases, phone conversations with the media, and postings through our social media channels formed the basis of our communication. Our messages encompassed a number of topics: the trip event itself, unit operational status, calls for voluntary energy conservation, a schedule of the rolling outages, the effected areas, and the status of the outages as they progressed.

COMMUNICATION PROCESS AND TIMELINE

What follows is a timeline of the events undertaken by the IMT to communicate the trip event and how it developed during the rest of the day and over the following two days.

January 12, 2015 Communication

Here is a timeline of the communication on January 12, 2015.

1:55 PM System Operations contacted us within minutes of the AES unit tripping offline and the initial load shedding event started. The load shedding affected approximately 20,325 customers throughout the island for about two to six minutes. We immediately began to work on creating messages to communicate the event to both Hawaiian Electric employees and our external audiences.

Simultaneously, we received a number of phone inquires from the news media about the outages. We told the news media about the lost of AES, our largest generator, and that Hawaiian Electric crews were currently working to quickly restore power.

From the information System Operations provided, we drafted, reviewed, and wrote a news release for immediate distribution to the news media.

1:55 PM Starting almost immediately after this first short outage and continuing until the end of the day (after evening peak passed), we communicated constantly with a number of entities. We updated the news media when they called with inquiries; and we engage our customers through social media channels, addressing their concerns, answering their questions, empathizing with them, and sharing the most updated information.

3:45 PM We distributed our first news release to the news media, key stakeholders, and emergency response contacts. (See “Distribution Lists” on page 60 for a list of these external audiences.) The news release described the loss of several generating units and the outages across Oʻahu, asked customers to conserve electricity, and told of the possibility of rolling outages that evening.

We posted the news release on the Hawaiian Electric website, adding a special banner to the home page to better call attention to the emergency alert. We also began a blitz of social media postings on our Twitter account, our Facebook page, and on our Goggle+ account. We posted messages to our Twitter account and posted on our Facebook/Google+ pages (linking to this news release). Our messages focused on advising customers to conserve energy and informing them about possible rolling outages. (For more details about our social media campaign and interactions, see “Communication Through Our Social Media Channels” on page 59.)

We sent an email to all employees about the entire situation—information they could use if asked about the units tripping and the resultant outages, and about the possibility of rolling outages that evening. We also posted a link to the news release on the company intranet carousel.

See “January 12, 2015; 3:35 PM: Loss of Power Generators Causes Oʻahu Outages” on page 146 to read this news release as issued.

4:00 PM We wanted to interact with the news media in person, so we held a news conference in the Ward Avenue customer service parking area. We took, and responded to, media questions about the news release and about the situation in general.

4:45 PM This second new release, following quickly on the heels of the first, updated our customers with developing events. Prominent in this news release was a schedule of the three hour-long rolling outages planned for the evening paired with the affected areas.

As with the previous release, we sent a corresponding email to all employees with this new information, posted the news release on our website and the intranet carousel, and to continued issuing messages through our Twitter account. In addition, our IMT constantly communicated with key stakeholders throughout the evening.

See "January 12, 2015; 4:35 PM: Rotating Outages to be Initiated on O'ahu" on page 148 to read this news release as issued.

4:50 PM We posted an initial schedule of the rolling outages on our website. The post included the anticipated beginning and ending times of the outages together with the effected areas.

7:30 PM We issued a third news release during the third rolling outage, essentially stating the status of what we had planned: that power had been restored to the customers who lost power, and that the third outage was in progress. This news release also included the entirety of the second news release.

As with the previous releases, we sent a corresponding email to all employees with this new information, posted the news release on our website and the intranet carousel, and posted messages through our social media channels. After the peak demand period, the IMT retired for the evening, however, internal and external communication continued.

See "January 12, 2015; 7:30 PM: Rotating Outages Initiated on O'ahu" on page 150 to read this news release as issued.

8:30 PM We issued our final news release of the day after the three rolling outages concluded. This release simply informed customers that power to all customers had been restored, and that no further outages were expected. This news release also included the previous two news release.

Again, we sent a corresponding email to all employees with this new information, posted the news release on our website and the intranet carousel, and posted messages through our social media channels. See "January 12, 2015; 8:30 PM: Power Retried to O'ahu Customers" on page 152 to read this news release as issued.

January 13, 2015 Communication

Early in the day, we issued a news release asking customers to continue to conserve electricity, especially during evening peak, and that no further rolling outages were expected.

As with yesterday's releases, we sent a corresponding email to all employees with this new information, posted the news release on our website and the intranet carousel, and posted messages through our social media channels. See "January 13, 2015: O'ahu

Customers Asked to Conserve Electricity" on page 155 to read this news release as issued.

Throughout the day, Corporate Communication staff quickly responded to all media inquiries.

January 14, 2015 Communication

We issued our final news release regarding this trip event. This news release lifted the call for energy conservation, and provided an update on the AES unit. See "January 14, 2015: Call for Energy Conservation Lifted" on page 157 to read this news release as issued.

Throughout the day, Corporate Communication staff responded to all media inquiries by giving an update about our current generation.

COMMUNICATION THROUGH OUR SOCIAL MEDIA CHANNELS

We communicate with our customers through Twitter and our Facebook/Google+ page. From the time when we issued our first news release, about 3:30 PM until after 10:00 PM, we continually engaged our customers, replying to their comments as necessary.

We issued 31 tweets: 26 on January 12 (within a period of about six hours) and the remaining 5 on January 13. Our Twitter account has an estimated 4,200 followers—people who directly receive our tweets (a Twitter message).

We responded to any Twitter follower who replied to one of our tweets with a question. We created, and used, the hashtag #OahuOutage, so the our followers would be able to keep track of all tweets we posted. See "Twitter Messages" on page 158 for a list of our tweets.

We posted on our Facebook/Google+ page each time we issued a news release, for a total of four postings. In each post, we summarized the current situation and provided a link to the most recent news release. As expected, customers commented and we replied as necessary. Our Facebook/Google+ page has an estimated 8,000 followers. See "Facebook/Google+ Posts" on page 160 for samples of our posts.

DISTRIBUTION LISTS

We send all of our communication releases to a number of distribution entities, that can be generally organized into three groups: news media, key stakeholders, and emergency response contacts.

News Media

News media distribution list

Key Stakeholders

Key stakeholders comprise the following organizations and people:

- Hawai'i Public Utilities Commission
- Hawai'i Consumer Advocate
- Hawai'i Emergency Management Agency (State Civil Defense)
- Honolulu Police Department
- Honolulu Fire Department
- State Senator Donna Kim
- State Senator Roz Baker
- State Senator Brian Taniguchi
- State Senator Mike Gabbard
- State Representative Joe Souki
- State Representative Sylvia Luke
- State Representative Scott Saiki
- State Representative Scott Nishimoto
- State Representative Chris Lee
- Honolulu City Managing Director Ember Shinn
- Honolulu City Council Chairman Ernie Martin
- Colleen Hanabusa
- Hawai'i Governor's office

Emergency Response Contacts

Emergency response contact distribution list

Key Accounts ?

key accounts distribution list

Key Employees ?

key employees distribution list

EVALUATING OUR COMMUNICATION

After the trip event and the threat of rolling outages was over, we took the time to evaluate our communication over the three days. We summarized that evaluation in six lessons learned, and developed some recommendations to better deal with the identified issues in the future.

Note to reviewers from Lynne Unemori, especially System Operations and Corporate Communication: Please evaluate the feasibility and practicality of these draft recommendations.

Earlier notification. Allow customers to plan better by notifying them earlier of possible rolling outages. Although we were first notified about the AES trip and resultant outages before 2:00 PM, we didn't issue our first news release until 3:45 PM, almost two hours later. See "Earlier Notification" on page 169 for examples of customer posts.

Recommendations: Use the news releases and other communication issued for this outage as templates to enable us to quickly prepare, review, and distribute informational messages for future events. As soon as possible, identify the duration and areas where outages might occur. Create and enforce a strict timeline and deadlines for editing and reviewing communication. Ensure that our Commercial Key Account managers and our Customer Business Management Service (CBMS) department effectively and efficiently communication with their customer contacts.

More specific outage locations. Identify specific locations that are affected by rolling outages. We received numerous social media comments as well as requests from the news media for this information. See "Specific Outage Locations" on page 169 for examples of customer posts.

Recommendations. Identify neighborhoods associated with our numerous circuits. Work closely with System Operations staff to better determine, as best as reasonable possibly, the specific streets and neighborhoods to be affected by an outage. Determine if Commercial Key Account managers and our Customer Business Management Service (CBMS) department need to identify the commercial customers in potential outage areas to communicate with them earlier.

Customer misunderstanding of our intent. Clearly describe the rationale of pending outages and their timing. We received numerous customer comments through our social media that demonstrated a misunderstanding as to why we would implement outages as certain times. Unfortunately, the rolling outages coincided with the 2015 College Football Playoff National Championship game that featured the Oregon Ducks led by quarterback Marcus Mariota, the year's Heisman Trophy winner and a Honolulu-born Samoan—a local favorite.

Some customers concluded that we purposely initiated outages during the football game; others wanted to know why outages couldn't be postponed until after the game concluded; and still others wondered why the rolling outages started later than the published scheduled times. See "Customers Misunderstanding Our Intent" on page 170 for examples of customer posts.

Recommendations. Enhance the breathe and depth of our messaging to answer anticipated questions and misunderstandings such as these in future prepared statements, new releases, and social media postings.

Overall positive response to our social media communication. For the most part, customers responded well to our social media posts. They retweeted our Twitter messages to their followers and shared our Facebook posted with their 'friends'. In addition, the news media reposted this information on their social media channels. All of this helped expand our sphere of communication and increased the number of customers receiving our messages. In general, customers were pleased with and appreciated our social media updates. See "Positive Customer Response" on page 171 for examples of customer posts.

Recommendations. Consider employing more communication tools (such as videos and photographs depicting response efforts, and a prepared list of energy conservation tips) to better use our social media channels to engage customers. Ensure that our messaging is conversational and friendly, as expected in social media interactions.

Creating the IMT challenged our ability to respond quickly. At a certain level, we were not fully prepared to respond to this sudden trip event and outage. The last time an event of this size and duration occurred was over six years ago. The scope of this outage was still being realized as the afternoon of January 12, 2015 progressed. This uncertainty about the length, severity, and timing of any resultant outage made it difficult for us to plan: select staff, assign tasks, and schedule additional shifts. As a result, certain tasks remained unassigned and the activity log created by the IMT was not adequately maintained.

Recommendations. Create an outline of a plan—including operational checklist—to ensure all actions and functions are considered and assigned to appropriate personnel.

Our IMT disbanded too early. When the threat of more outages passed on the evening of 12 January 2015, we disbanded the IMT. Because of this, we did not have enough staff to gather more information, create messages, and communicate with the news media and our customers. This need continued for two more days until the call of energy conservation was lifted. While these communication needs were ultimately met, an intact IMT would have facilitated our communication efforts.

Recommendations. The PIO and the Incident Commander should carefully consider the members of an IMT and how long each member must remain active to better facilitate the creation, approval, and issuance of messages for the duration of an event.

4. Customer Communication

Hawaiian Electric publishes a handful of local and toll-free phone numbers for customers to use when calling about any electricity-related issue—such as outages. Over the course of January 12 afternoon and evening, about 1,600 of them did just that.

Most customers called our power outage toll-free line: 1-855-304-1212. Virtually all other customers called our Customer Service line: 1-808-548-7311. Customers can quickly access a list of these and all other contact phone numbers by clicking the 'Contact Us' link at the top of our website's home page.

MESSAGES FOR OUR CUSTOMERS

When customers call, they immediately hear a polite prerecorded messages greeting them, then directing them on how to proceed if they are calling about a power outage. In industry terms, this prerecorded message is referred to as an all-caller message, simply because every caller hears this message.

These lines use a interactive voice recognition (IVR) system. Customers can either push a number on their phone to direct their call, or simply speak the option they want. One option, of course, is to speak live with a Customer Service representative.

When situations occur that affect many customers—such as this outage—our Customer Service Department changes the prerecorded message to one more pertinent to the situation.

During the afternoon of January 12, customers heard the standard all-caller message. Customers who called during this time and chose to speak with a company representative were informed about the pending outage situation; about voluntary energy conservation; and about the where, when, and how long the outages would last.

For evening peak, Customer Service recorded and loaded more specific messages, changing them the situation warranted. Customers started receiving this message (with the variable information in brackets) starting at about 6:00 PM:

> "We are currently implementing rolling blackouts in the [neighborhood] area. The duration of the outage will last approximately one hour starting from [starting time]. We apologize for the inconvenience."

Customer Service changed this message every time the neighborhood and time changed. Many customers who called hung up immediately after hearing this message. Most chose to speak with a Customer Service representative.

Customers did not experience long waits before their call was answered by a Representative. We ensured that a sufficient number of our representative were available to take calls at all three of our call centers: on O'ahu, Maui, and Hawai'i Island. Our representative informed customers that rolling outages were currently be implemented, the areas affected by their outages, and how long they were expected to last. Representatives received and related updated information over the course of the rolling outages.

Our IVR system captures metrics about the phone calls we received every 30 minutes. Rolling outages started about 6:30 PM. Between 6:00 PM and 7:59 PM, we received 1,549 customer calls.

The tenor of the conversations was generally positive and civil. While we heard about a number of issues, customers mainly complained about the outages coinciding with the BCS Championship Football game and about being notified of the outages late in the day. We did tell customers that customer energy conservation helped delay the start of the outages, and shorten their duration.

ASSESSMENT OF OUR CUSTOMER COMMUNICATION

Our prerecorded message about the start, location, and duration of the outages helped many customers. Approximately 40% of callers hung up after listening to this message. The IVR message enabled customers to obtain necessary information quickly, thus avoiding waiting for a live representative.

In the future, we would like to be more proactive in broadcasting this type of information. For example, we could use mobile technologies to automatically call customers or text them, and to email them with pertinent, updated, relevant information. This would enable us to directly contact customers with this vital information, rather than passively waiting for them to contact us.

5. Event Analysis

Every year, Hawaiian Electric files an Adequacy of Supply (AOS) report. This report indicates how the generation capacity on the O'ahu power grid is able to meet all reasonably expected demand as well as provide a reasonable reserve to meet emergencies. The AOS incorporates a Loss-of-Load Probability (LOLP) of, at most, one outage day every 4½ years in its overall capacity planning criteria.

The January 12, 2015 outage was the first generation shortfall on the O'ahu grid since early 2008, a period of over six years which falls well within our current capacity planning criteria. The outage, however, appeared to garner more criticism because, unfortunately, it coincided with the college football championship game that featured local favorite and Honolulu-born Marcus Mariota.

The outage did not coincide with annual peak. Outages occur because a number of generation units trip offline, are on forced outages, or are derated—all of which are simply random events.

DETERMINING ADEQUACY OF SUPPLY

The capacity of our entire fleet of firm generation is sufficiently large to meet all reasonably expected demand with a reasonable reserve for emergencies.

Our annual Adequacy of Supply (AOS) report assesses the generating reliability for the Oahu power grid. The AOS is based upon our Capacity Planning Criteria made up of two factors called Rule 1 Criteria and a Reliability Guidelines.

The total system capability including interruptible load—called Rule 1 Criteria—must be at least equal to the anticipated peak load minus unit maintenance, derates, and the largest unit in service. Our system Reliability Guideline includes the total generation loss of load probability (LOLP), and sets a threshold of, at most, one day for every 4½ years.

Our 2015 AOS report concluded that our firm generation capacity satisfies Rule 1, however we might not be able to meet the Reliability Guideline[7] in the first quarter of 2015 and starting in 2017. For the first quarter of 2015, an excessive number of forced outages led to our uncertainty about meeting the Reliability Guideline. Starting in 2017, the Reliability Guideline is called into question because of the planning deactivation of Waiau 3 and Waiau 4 with a combined capacity of 98 MW.

Variable distributed generation, which is mostly DG-PV, cannot be relied upon to meet a potential generation shortfall, especially during evening peak as the sun sets. This situation will exacerbate as DG-PV becomes a larger potion of our generation mix.

CAPACITY PLANNING CRITERIA FOR 2015

We assess the adequacy of our supply by considering two requirements: Rule 1 Criteria and a Reliability Guideline.[8]

Rule 1 Criteria

Our Rule 1 Criteria states that total system capacity plus the total amount of interruptible loads must, at all times, be equal to or greater than the sum of:

- The capacity needed to serve the estimated system peak load
- The capacity of the unit scheduled for maintenance
- The capacity that would be lost by the forced outage of the largest unit in service.

The calculation of Rule 1 benefits from interruptible load customers. Interruptible load programs (such as Rider I and load management programs) defer the need for additional firm capacity generation.

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7 This sentence clarifies a statement in Hawaiian Electric's 2015 AOS report that stated, "…Hawaiian Electric's firm generating capacity, which does not include intermittent energy sources such as wind and solar may not be sufficient to meet projected peak demand in the first quarter of 2015 and from 2017 on."

8 With our 2015 Adequacy of Supply filing, we stopped calculating a Rule 2 criteria used in previous filings, mainly because the characteristics of the O'ahu power grid have substantially changed. This Rule 2 considered the dynamic response of the power grid—the amount of reserve power available within three seconds. Appendix M of our Power Supply Improvement Plan (filed August 26, 2014 in Docket No. 2011-0206) detailed the draft planning standards that, together with the generating system reliability (LOLP) analyses, we will use to assess the adequacy of supply.

Our adequacy of supply can be determined through Rule 1 by adding or subtracting capacity without regard to the probability that such capacity will be available at any given point in time. Rule 1 is calculated by this equation:

  Total capacity of the system
– Capacity of unavailable units on planned maintenance
– <u>Capacity of the largest available unit</u>
  Rule 1 criteria

Then, simply compare this result with a reduced system peak:

Rule 1 criteria > (system peak – total interruptible loads) = no additional capacity needed

Rule 1 criteria ≤ (system peak – total interruptible loads) = additional capacity needed

The probability that the largest unit might be lost from service during the peak is not a factor when applying this rule.

Analysis of Rule 1 Criteria

Table 8 lists the excess capacity that satisfies the Rule 1 criteria from the 2014 and 2015 Adequacy of Supply reports.

Year	2014 AOS Rule 1 Results: Excess Generation	2015 AOS Rule 1 Results: Excess Generation
2014	160 MW	—
2015	175 MW	56 MW
2016	120 MW	179 MW
2017	114 MW	72 MW
2018	125 MW	56 MW
2019	—	132 MW

Table 8. Adequacy of Supply Rule 1 Results: 2014–2019

Notice, however, how the excess generation for 2015, 2017, and 2018 differ greatly between the amounts calculated in the 2014 AOS and the 2015 AOS. Several reasons account for these differences.

The 2015 AOS included the most recent maintenance schedules, which called for a number of planned outages early in 2015, thus the 56 MW excess generation compared with 175 MW calculated for the 2014 AOS. Also the 2015 AOS forecasted the deactivation of Waiau 3 and Waiau 4, reducing overall capacity by 98 MW, and thus reducing excess generation. 2019 brings the forecast of burning LNG, a much cleaner fuel, thus reducing the maintenance necessary to comply with MATS standards.

Reliability Guideline: Loss-of-Load Probability (LOLP) Analysis

The reliability guideline, as its name suggests, accounts for the unexpected loss from service of our generating units—a loss-of-load probability (LOLP). We then compare this calculated LOLP against our baseline reliability guideline threshold of 4½ years per day.

We plan to generate enough capacity every day to ensure that the probability of a generation shortfall occurs, at most, only one day every 4½ years. In actuality, we plan to ensure there is always enough generating capacity on the system to account for the contingency that multiple units are unexpectedly lost from service on any given day. In others words, our LOLP calculation must exceed the 4 ½ years per day criteria. LOLP is the probability of a generation shortfall from a system perspective (not a unit perspective).

To calculate our LOLP, we consider the number of units on the system, the rating of these units, the loads these units serve, the units capacity values, the forced outage rate (EFORd value), the maintenance outage rate, the planned outage rate, demand response, as well as other factors (such as the age of the unit).

We have established our LOLP and the reliability guideline of 4 ½ years per day to create a balance among what is acceptable for our power grid, the associated costs with maintaining this standard, and the costs of the infrastructure to maintain this standard.

On January 12, 2015, our power grid experienced that one day of generation shortfall that we assiduously work to avoid. This outage, however, was well within our 4½ reliability guideline threshold—the last such outage occurred over 6 years ago.

Potential for Future Repeat Outage Event

The current LOLP guideline and current system conditions point to a greater potential for repeat outages in the future. As such, we must evaluate changing the LOLP guideline, altering our generation operation, incorporating new resources, and adding alternative resources (such as demand response, load shifting, and distributed generation).

Our power grid is rapidly incorporating increasing amounts of variable wind and PV generation. We simply cannot rely on being able to dispatch this generation at a specific level to serve load, especially peak load. Determining their capacity value (that is, the variable resource's ability to replace firm generation) with a high level of confidence is a considerable challenge. Notwithstanding this uncertainty, estimated capacity values of variable generation and demand response are reflected in the LOLP calculations. Incorporating these estimated capacity values, however, makes the LOLP less certain.

Increasingly, we must respond to quickly changing factors (such as changes in peak demand and unit availability factors), many of which also change from year to year. To address these changing factors, we could move toward a higher reliability guideline.

The average mainland standard, with its interconnected grids and access to power pools, is 10 years per day. In August 2006 testimony, the Consumer Advocate called for evaluating our reliability guideline, offering a 6 years per day example as a means of ensuring reliable service.

Any movement toward our increasing the number of years in our reliability guideline to approach the mainland standard will increase costs. The Consumer Advocate, during testimony, called for assessing "the tradeoff between electric service costs to the consumer and the increase in reliability to be gained". This more conservative reliability guideline, however, would begin to address the increasing uncertainty in our capacity planning.

FACTORS INFLUENCING GENERATION SYSTEM RELIABILITY

While many factors influence generation system reliability, three factors stand out: Equivalent Demand Forced Outage Rates (EFORd), maintenance schedules, and the capacity value of wind.

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. Every year, we update estimated EFORd values for our AOS report.

We calculate EFORd values by averaging the last five years of actual EFORd values (from actual unit performance). We base our calculations on a combination of historical data, experience, and operational judgment. Predicting unit-specific EFORd values is extremely difficult. The variation of historical values bears out this difficulty. Nonetheless, for our planning, we must estimate future EFORd values for all firm generation units. EFORd projected values are not certain; actual experience most likely will vary from these projections. Taken as a whole, though, the average of all EFORd values remains within a few percentage points from year to year.

To ease the calculations of some EFORd values, we group similar units together: Waiau 5 with Waiau 6, Waiau 7 with Waiau 8, Waiau 9 with Waiau 10, Kahe 1 with Kahe 2, Kahe 3 with Kahe 4, and Kahe 5 with Kahe 6. Because of certain individual characteristics, we calculate the EFORd values for Waiau 3, Waiau 4, and CIP CT-1 separately.

We base EFORd values for our IPP units on estimated values for our capacity planning. The EFORd values of these IPP units remain relatively stable. We assign EFORd values of 1.5% for AES Hawaiʻi and both Kalaeloa units, and 3% for H-POWER.

Table 9 lists the historical and projected EFORd values for our utility-owned firm generation units, comparing the estimated with actual values for 2013 and 2014.

Unit	2009	2010	2011	2012	Projected 2013	Actual 2013	Projected 2014	Actual 2014	Projected 2015
Waiau 3	0.8%	3.3%	11.2%	4.4%	6.1%	13.7%	6.7%	33.2%	13.2%
Waiau 4	5.5%	0.9%	9.0%	2.2%	4.9%	1.7%	3.8%	5.0%	3.8%
Waiau 5	2.7%	1.6%	0.5%	1.9%	2.6%	1.4%	2.0%	3.5%	2.7%
Waiau 6	0.0%	0.2%	2.2%	6.5%	2.6%	2.4%	2.0%	7.2%	2.7%
Waiau 7	2.4%	0.1%	7.4%	0.4%	4.6%	1.6%	3.7%	0.0%	3.8%
Waiau 8	1.9%	1.3%	11.2%	3.7%	4.6%	4.7%	3.7%	6.7%	3.8%
Waiau 9	1.3%	0.6%	8.6%	25.5%	7.7%	2.1%	7.2%	0.9%	7.2%
Waiau 10	3.6%	9.0%	9.8%	4.8%	7.7%	7.1%	7.2%	3.4%	7.2%
Kahe 1	2.4%	0.7%	2.7%	0.5%	3.8%	0.6%	3.6%	2.8%	4.0%
Kahe 2	7.7%	8.8%	2.4%	7.2%	3.8%	3.1%	3.6%	10.6%	4.0%
Kahe 3	3.8%	3.9%	2.2%	2.5%	4.6%	1.3%	3.7%	2.2%	3.8%
Kahe 4	7.0%	10.4%	3.0%	2.7%	4.6%	2.3%	3.7%	9.0%	3.8%
Kahe 5	9.0%	1.1%	6.0%	4.6%	4.0%	2.3%	4.7%	6.1%	4.3%
Kahe 6	3.3%	2.0%	3.0%	3.4%	2.6%	12.8%	4.7%	1.8%	4.3%
CIP CT-1	18.3%	9.9%	8.4%	3.9%	10.1%	0.7%	8.2%	9.0%	6.4%
Average	3.5%	3.8%	5.0%	4.1%	4.1%	3.4%	4.0%	5.9%	4.1%

Table 9. Historical Actuals and Projected EFORd

Clearly, the historical EFORd values for each unit can increase or decrease from year to year. Our annual projected EFORd values average around 4.0%. While these values vary from year to year, the historical average of actual EFORd values is 4.3%. In other words, we expect each unit to be on forced outage or derated, on average, about 4.3% of the year when we plan for our available capacity.

Refer to "Appendix E: Unit EFOR(d) Explanations" (page 139) for details on how we arrived at the EFORd for each of our generation units.

Maintenance Schedules

Annually, we create a maintenance schedule for each unit for the current and for subsequent years. Units are offline and unavailable when on a maintenance outage. Units are overhauled over time, and are also offline and unavailable during these planned outages. Our maintenance schedules tend to follow a regular pattern and thus do not change significantly from year to year. We use these maintenance schedules when preparing our annual AOS report.

The AES, H-POWER, and Kalaeloa IPP units also have maintenance schedules prepared for them, which we merge into our maintenance schedules.

We then take these maintenance outages and planned outages into consideration when developing our capacity planning projections. These outages, of course, reduce available generating capacity.

The amount of time a unit is offline for maintenance and overhauling can change because of unforeseen circumstances and problems when we are working on the unit. These only serve to lengthen the amount of time a unit is offline. Whenever this happens, we revise the maintenance schedules.

Almost all units offline during the outages experienced on January 12, 2015 were either being repaired, on forced outages, tripped offline, or derated. Only one unit, Kahe 4 at 89 MW, was on planned maintenance.

Capacity Value of Wind

Because wind and solar are variable generating resources, determining their capacity value to supplement or replace firm generation with a high level of confidence presents a considerable challenge. We employed an LOLP analysis to determine the capacity value of existing and future wind resources. We reflect these capacity values to show wind's contribution to serving load.

Through our analysis, we determined the aggregate capacity value of our two existing wind facilities (30 MW for Kahuku Wind and 69 MW for Kawailoa Wind) to be approximately 10 MW, or about 10% of the nameplate capacity. (Mainland utilities also assign a 10% capacity value to wind.) We used this capacity value to derive the results detailed in our 2015 AOS report. We are still evaluating the accuracy of wind's 10% capacity value.

We realize, of course, and include in our capacity planning the fact that our wind resources are variable, and might be generating power anywhere from 0 MW to their capacity of 99 MW. Because we cannot count on wind being available to forestall a generation shortfall, we only use the assigned 10% capacity value in our planning.

The January 12, 2015 trip event is a perfect example of how unreliable wind generation can be. During that day and the next, our entire wind generation fluctuated between 0.2 MW and 3.6 MW.

Our LOLP calculations use a value for net peak demand. Because utility-scale PV and DG-PV do not generation power during the evening demand period, the capacity value of PV is 0.

RESERVE MARGIN

Every year in our Adequacy of Supply report, we list the actual reserve margin for the previous year, then calculate the reserve margin for the upcoming year and for the next four years.

How Reserve Margin Is Calculated

The reserve margin measures the amount of installed generating capacity relative to the annual peak load, and can be expressed as a percentage of the peak demand. It is calculated by taking the difference between total generating system capacity and the system annual peak load and then dividing the result by the system annual peak load.

Expressed as an equation, reserve is calculated as follows:

$$\text{Reserve Margin} = \frac{\text{Total Net Generating Capacity} - (\text{System Peak Demand} - \text{Interruptible Load})}{(\text{System Peak Demand} - \text{Interruptible Load})}$$

Total Generating Capacity is computed at the time of annual peak load. It includes both utility-owned and IPP firm generation—variable generation (wind, utility-scale photovoltaics, and DG-PV) is not included—plus the airport's Dispatchable Standby Generation (DSG).

Every year, using projected annual peak loads and expected capacity resources available to meet those loads, we calculate reserve margins for the current year and the upcoming four years. We then compare these calculations with established standards to determine if we need to add resources to the system.

We can consider interruptible loads in our analysis by either including the interruptible load as a resource or by reducing the peak load by the amount of available interruptible loads. We can also consider variable generation resources by including the estimated capacity value from each resource.

Reserve Margins for 2014 and 2015

With the continued increase in the amount of variable generation on the system, especially DG-PV, we forecast the reserve margin to keep decreasing in the upcoming years. Compare the reserve margins that we published in the 2014 Adequacy of Supply and 2015 Adequacy of Supply reports.

2014–2015 Reserve Margins

Year	2014 Reserve Margin	2015 Reserve Margin with Variable Generation	2015 Reserve Margin without Variable Generation
2013	61%	—	—
2014	49%	47%	46%
2015	47%	45%	44%
2016	47%	45%	44%
2017	37%	35%	34%
2018	37%	35%	34%
2019	—	34%	33%

Table 10. 2014–2015 Reserve Margin Percentages

See "Appendix D. Reserve Margin Calculations" (page 136) for an explanation of how we calculated these reserve margins.

Reserve Margin: January 12 and 13, 2015

We calculated the reserve margins for January 12 and 13, 2015 using the specific capacity, peak demand, and interruptible load for each day.

On 12 January 2015, the forecasted system demand was 1,030 MW; the forecasted interruptible load was 26 MW. During evening demand, wind generation averaged less than 1 MW. Thus, the evening reserve margin was calculated as –6.3%, indicating that the expected peak demand exceeded the amount of available capacity. Table 11 shows how this reserve margin was calculated.

Unit	Gross Capacity	Derate	Available Gross Capacity	Available Generation: Day Peak	Available Generation: Evening Peak
Kahe 1	86	–11	75	71	71
Kahe 2	86	—	86	82	82
Kahe 3	90	—	90	86	86
Kahe 4	89	–89	0	0	0
Kahe 5	142	–142	0	0	0
Kahe 6	142	_142	0	0	0
Waiau 3	49	—	49	47	47
Waiau 4	49	—	49	46	46
Waiau 5	57	—	57	55	55
Waiau 6	56	–21	35	33	33
Waiau 7	87	—	87	83	83
Waiau 8	90	—	90	86	86
Waiau 9	47	—	47	47	47
Waiau 10	44	—	44	44	44
CIP CT-1	113	—	113	0	112
Subtotal	*1,227*	*–405*	*822*	*681*	*793*
H-POWER	69	–11	58	58	58
Kalaeloa CT-1	104	–14	90	90	90
Kalaeloa CT-2	104	–104	0	0	0
AES	180	—	180	180	180
IPP Subtotal	*457*	*–129*	*328*	*328*	*328*
Spinning Reserve of the Largest Unit				180	180
Capacity (available gross capacity – spinning reserve)				829	941
Peak Forecast				830	1,030
Interruptible Load Forecast				26	26
Excess Operating Spinning Reserve				–1	–89
Reserve Margin				*3.1%*	*–6.3%*

Table 11. Reserve Margin for Monday, 12 January 2015

On 13 January 2015, the forecasted system demand and the forecasted interruptible load was the same as the previous day. During evening demand, wind generation also averaged less than 1 MW. Several Hawaiian Electric and IPP units were in various stages of returning to service. Thus, the evening reserve margin was calculated as –9.7%, indicating that the expected peak demand exceeded the amount of available capacity. Excess spinning reserve, however, enabled us to meet evening peak demand.

Table 12 shows how this reserve margin was calculated.

Unit	Gross Capacity	Derate	Available Gross Capacity	Available Generation: Day Peak	Available Generation: Evening Peak
Kahe 1	86	–11	75	71	71
Kahe 2	86	—	86	82	82
Kahe 3	90	—	90	86	86
Kahe 4	89	–89	0	0	0
Kahe 5	142	–142	0	0	0
Kahe 6	142	_142	0	0	0
Waiau 3	49	—	49	47	47
Waiau 4	49	—	49	46	46
Waiau 5	57	—	57	55	55
Waiau 6	56	–21	35	33	33
Waiau 7	87	—	87	83	83
Waiau 8	90	—	90	86	86
Waiau 9	47	—	47	0	47
Waiau 10	44	—	44	44	44
CIP CT-1	113	—	113	112	112
Subtotal	*1,227*	*–405*	*822*	*746*	*793*
H-POWER	69	–14	55	55	55
Kalaeloa CT-1	104	–14	90	90	90
Kalaeloa CT-2	104	–104	0	0	0
AES	180	–98	82	82	82
IPP Subtotal	*457*	*–230*	*227*	*227*	*227*
Spinning Reserve of the Largest Unit				113	113
Capacity (available gross capacity – spinning reserve)				860	907
Peak Forecast				810	1,030
Interruptible Load Forecast				26	26
Excess Operating Spinning Reserve				50	–123
Reserve Margin				*9.7%*	*–9.7%*

Table 12. Reserve Margin for Tuesday, 13 January 2015

Had the Honolulu Generating Station been activated, Honolulu 8 would have added 53 MW and Honolulu 9 would have added 54 MW to available capacity. If both units were available on January 12, the evening reserve margin would have been 4.4% thus mitigating the generation shortfall. Rolling outages would have been avoided. If both units were available on January 13, the evening reserve margin would have been 1.0%.

A Reserve Margin of 30%

Currently, system planning aims to exceed a 20% reserve margin. We are, however, realizing that, with the increased amount of variable generation on the system, a 30% reserve margin is a more realistic threshold.

On the United States mainland, reserve margins typically range between 12%–15%. Mainland utilities are interconnected, thus they can purchase power from one another when they are experiencing a generation shortfall. In addition, mainland utilities can purchase power from a regionalized power pool. For example, all utilities in New England (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut) can readily purchase power from NEPOOL, the New England Power Pool. Both of these factors contribute to mainland utilities carrying smaller spinning reserve, and thus can plan to effectively meet demand using these low reserve margins.

Isolated, independent utilities, such as Hawaiian Electric, cannot rely on either of these options. Island systems around the world are also being challenged to meet present and future energy needs in a sustainable and reliable way. A EURELETRIC Report stated: "In order to counteract systemic risks, most islands operate with generation margins of around 30%–40% compared to 15%–20% in mainland highly interconnected grid systems". Because of its geographical isolation, the state of Alaska (AKRES-001-0) developed a 30% reserve obligation standard.

We referenced this standard as necessary for calculating our reserve margins in the future, and based our planned transformation to a 30% reserve margin on that document's conclusions. As a result, our PSIP used a 30% reserve margin for its analysis when planning for transforming the Hawaiian Electric power grid. In addition, the PSIP introduced the draft planning criteria, BAL-502, which provided for calculating future reserve margins of 30% or greater.

A number of factors lead to our planning to be more conservative and use a 30% reserve margin. We are currently assigning capacity values to demand response, utility-scale renewable generation (including wind and PV), and energy storage to be used in calculating future reserve margins. The ever increasing amounts of uncontrollable DG-PV coupled with increasing peak demand forecasts form the more fundamental factors for raising our reserve margin threshold to 30%.

Our reserve margins in recent AOS reports appear in the 30%–40% range. Our review of other island systems and the evolving mix of generation resources makes us seriously consider that a reserve margin on the order of 40% might be most prudent. We must consider this for better managing our risk.[9]

Increasing amounts of variable generation make it prudent for us to ensure enough generation capacity to meet our capacity planning criteria to avoid generation shortfalls in the future.

[9] Refer also to Docket No. 2012-0212, Hawaii Electric Light's Power Supply Plan, submitted on April 21, 2014, Exhibit 1, EU Islands: Towards a Sustainable Energy Future, page 19.

6. Solar Generation's Impact

The Oahu generation grid is changing rapidly and requires new tools and procedures to accommodate those changes. The biggest change is the addition of large amounts of photovoltaic (PV) generation, most of which has been installed on residential and commercial rooftops (about 250 MW to date). The amount will only continue to increase.

The O'ahu grid is already running into challenges with this high DG-PV saturation. We are researching and evaluating different methods for incorporating higher levels of DG-PV, however, managing the grid as a whole faces substantial challenges to maintain high levels of reliability.

The reliability of Hawaiian Electric's generating unit fleet is vitally important to ensure load demands are met at all times of the day, for integrating variable generation, supplying ancillary services not provided by other generating systems, and supplying peak load demands, which occur in the evening when PV systems are not generating.

What we wrote in our PSIP bears repeating:

> Each increment of variable generation has to be balanced by firm generation assets (fossil or renewable) and/or energy storage to meet various system reliability criteria. To manage this reality, the firm generation resource mix has to be changed over time. This transformation is made by first increasing operational flexibility of existing steam generating units from baseload to cycling, improved turndown, and enhanced ramp rates, then acquiring new flexible firm generation as these steam generators are retired.
>
> There is also a cost for operating thermal generating units at lower output to manage the regulating reserve requirements that increase each year as more and more variable renewable resources are added to the system. The lower output of the firm, dispatchable assets results in less efficient operations of these assets (similar to "car gas mileage is worse at 10 mph than at 50 mph"). Additional starts and stops of the thermal

generating units to counter balance the outputs of the variable generation assets are expected to increase maintenance costs.

GENERATION UNIT OPERATIONS

Our generation mix has changed dramatically over the past seven years.

Historical Operation

In 2008 when we filed our IRP-4, our generation portfolio comprised virtually 100% of firm generation.

Unit	Fuel	Type	Gross Maximum	Net Maximum	Gross Minimum	Net Minimum
Kahe 1	LSFO	Baseload	92.0	88.2	35.0	32.5
Kahe 2	LSFO	Baseload	90.0	86.3	35.0	32.7
Kahe 3	LSFO	Baseload	92.0	88.2	35.0	32.3
Kahe 4	LSFO	Baseload	93.0	89.2	35.0	32.3
Kahe 5	LSFO	Baseload	142.0	134.7	55.0	50.7
Kahe 6	LSFO	Baseload	142.0	133.9	55.0	50.0
Waiau 3	LSFO	Cycling	49.0	46.2	24.0	22.3
Waiau 4	LSFO	Cycling	49.0	46.4	24.0	22.3
Waiau 5	LSFO	Cycling	57.0	54.6	24.0	22.5
Waiau 6	LSFO	Cycling	58.0	55.6	24.0	22.5
Waiau 7	LSFO	Baseload	92.0	88.1	35.0	32.6
Waiau 8	LSFO	Baseload	92.0	88.1	35.0	32.8
Waiau 9 (CT)	Diesel	Peaker	52.0	51.9	6.0	5.9
Waiau 10 (CT)	Diesel	Peaker	50.0	49.9	6.0	5.9
Honolulu 8	LSFO	Deactivated	56.0	52.9	24.0	22.3
Honolulu 9	LSFO	Deactivated	57.0	54.4	24.0	22.3
Subtotal	—	—	*1,263.0*	*1,208.6*	*476.0*	*441.9*
AES Hawai'i	Coal	Baseload	180.0	180.0	63.0	63.0
H-POWER (HRRV)	Refuse	Baseload	46.0	46.0	23.0	23.0
Kalaeloa (KPLP)	LSFO	Baseload	180.0	180.0	60.0	60.0
Subtotal	—	Baseload	*406.0*	*406.0*	*146.0*	*146.0*
Totals	**—**	**—**	**1,669.0**	**1,614.6**	**622.0**	**587.9**

Table 13. O'ahu Generation, 2008

In addition, we purchased 3.67 million kWh of non-firm variable energy from Tesoro Hawaiʻi and 90,000 kWh from Chevron.

Current Operations

Today, the situation has changed dramatically.

Our current capacity includes 1,227 MW of utility-owned and 456.5 MW of IPP-run firm generation; 99.0 MW of wind generation; 11 MW of station PV; and approximately 250 MW of DG-PV supplied through the net energy metering (NEM), system interconnection agreement (SIA), and feed-in tariff (FIT) programs. (See Table 1 on page 12 for a breakdown of this generation.)

Our total generation is approximately 2,043.5 MW of capacity. Firm generation comprises about 80%, while variable generation comprises the remaining 20% of capacity.

Probability of Future Operations

Variable wind and PV generation will continue to grow.

Two signed PPAs[10] totaling 44 MW were signed and are currently undergoing regulatory review. The Commission granted waivers from competitive bidding for three of five PV projects[11] with a combined total of 33 MW.

The planned Schofield generating station project, scheduled for later 2017, would add 50 MW of firm generation. This unit will enable us to deactivate existing firm generation. The unit's reciprocating engines will enable us to add increased amounts of variable renewable energy and provide additional energy security to O'ahu due to its siting away from coastal effects.

Finally, we anticipate that ongoing NEM, SIA, and FIT programs could add hundreds of MW of more PV capacity to the system over the next several years.

We issued a Request for Proposals (RFP) for one or more large-scale energy storage systems (ESS) able to store 60 to 200 MW for up to 30 minutes. This project, employing the best available technologies (including batteries, mechanical flywheels, capacitors, compressed gas systems, pumped hydro storage or a combination of such technologies) is scheduled for installation during the first quarter of 2017.

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10 Docket Nos. 2013-0423 and 2014-0077.

11 Decision and Order No. 31913, issued February 13, 2014, Docket 2013-0156. Two other utility-scale PV project totaling 222.5 MW was not granted a waiver.

THE EFFECTS OF DG-PV ON DEMAND

The demand for electricity on Oahu is not constant throughout the day. Five years ago, the demand was low overnight with a gradual trend upward until late morning. From late morning until late afternoon, demand was relatively level followed by a three to four hour peak in demand before dropping back down to overnight demand levels. Over the last five years, however, this demand pattern has changed, and projects to continue to change into the future.

Figure 20 (created two years ago) depicts this demand evolution. The blue line (labeled "7/10-6/11") shows the average demand curve from July 2010 through June 2011. While both DG-PV and utility-scale PV contributed to these demand curves, currently DG-PV represents about 95% of PV generation and thus has, by far, the greatest impact on these demand curves.

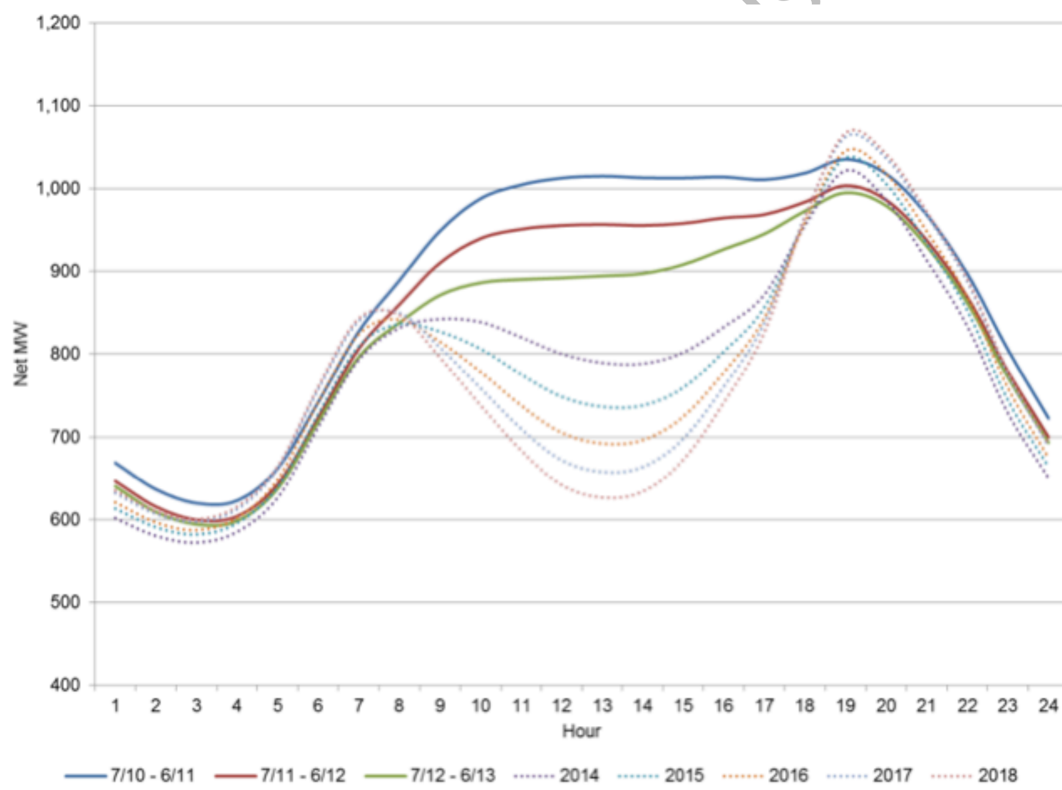

Figure 20. Evolving Demand Profile from DG-PV Growth

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.

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 low because DG-PV generation is low.

PV systems installed through the NEM, SIA, and FIT programs are referred to as behind-the-meter systems. These systems provide energy directly to the PV system's owner that we can neither directly monitor, nor control or curtail. The generation from these systems must be accepted by the grid. Utility-scale systems—both utility-owned or IPP-owned—are installation whose output we can directly or indirectly monitor, control, and curtail.

Although curtailment can be considered a tool to help manage the grid, we consider it an option of last resort. Additional tools need to be considered and implemented to reduce the need for curtailment as much as practical.

The current level of PV generation creates challenges with maintaining system frequency. Current tools, while effectively managing the grid, are being stretched to their limits. Additional tools are required for the grid to accommodate the anticipated levels of PV generation.

FREQUENCY CONTROL

To ensure a functional and reliable grid, electric frequency must be maintained very close to 60 Hz (cycles per second). When the supply of electricity exactly matches demand, grid frequency is held at a stable level. Our system operators seeks to continuously balance electricity supply with demand to maintain the proper frequency. This is done by continually varying the output of firm power generators.

The current fleet of firm power generation was sufficiently capable of managing the relatively small demand fluctuations the grid experienced before the addition of substantial levels of variable generation.

At today's level of fluctuations, the current fleet is able to manage well except for infrequent occasions when PV generation rapidly changes due to quick moving cloud cover. So far those infrequent occasions have caused what are considered unacceptable frequency deviations, but have not gotten to the level where customers' power was required to be temporarily shut off until frequency was restored to acceptable levels. While the frequency does fluctuate more, it rarely falls outside of an acceptable range.

One factor that has helped so far in minimizing the load swings from PV generation is that it is distributed throughout the island. Therefore, a single fast moving cloud tends to only affect the amount of PV in localized regions. However, as higher and higher density levels of circuit-level PV are installed, larger grid-level frequency deviations are occurring. In addition, as large utility-scale systems are installed, these frequency deviation events are likely to occur more often since those installations will have very high density levels of PV generation.

While acceptable now, the current tools available to manage frequency within tolerance are not sufficient for the future. There are two primary tools that can be used to help with this situation: energy storage and fast-ramping firm generation.

Energy Storage for Frequency Control

There are many types of energy storage that have been commercialized or are in development. While several of the technologies may be able to provide frequency control, the only two practical means of providing this service on Oahu today are flywheels and batteries. For this particular application, Hawaiian Electric believes flywheels are the superior choice over batteries.

Flywheels

Flywheel energy storage works by accelerating a cylindrical assembly called a rotor (flywheel) to a very high speed and maintaining the energy in the system as rotational energy. The energy is converted back by slowing down the flywheel. The flywheel system itself is a kinetic (or mechanical battery) spinning at very high speeds to store energy that is instantly available when needed.

The rotor is made up of various components, including a motor and generator mounted to the shaft. When charging (or absorbing) energy, the flywheel's motor acts like a load and draws power from the grid to accelerate the rotor to a higher speed. When discharging, the motor is switched into generator mode, and the inertial energy of the rotor drives the generator which, in turn, creates electricity that is then injected back into the grid. Multiple flywheels can be connected together to provide various megawatt-level power capacities.

The rotor is levitated on hybrid magnetic bearings operating in a near-frictionless vacuum-sealed environment. Because the magnetic bearings do not suffer the wear that standard bearings do and due to the high-strength materials of the rotor, the flywheels can operate for 20 years with minimal maintenance. Also, the flywheel does not lose any of its capacity over its lifetime. This makes flywheels an excellent choice for continuous frequency control since they can undergo hundreds of thousands of cycles before they reach the end of their useful life.

Batteries

Batteries produce energy based on natural electromotive forces between their electrodes. The chemical reaction between the electrodes occurs within the electrolyte of the battery. Over time, the chemical reaction forms a coating on the electrodes or changes the properties of the electrolyte such that the electromotive force weakens and the battery can no longer produce power at its rated voltage. Rechargeable batteries allow for the chemical reactions to be reversed, thereby restoring their power producing capability. This process of recharging the batteries is a way to store energy.

Each time a battery is used and then recharged (cycled), the electrodes and the electrolyte undergo changes. At first, these changes are minor and do not affect the battery performance. Over time, however, the accumulated changes will be significant enough so that the battery can no longer be recharged. In general, the more cycles the battery experiences in a given time, the faster it will reach its end of life.

Since continuous frequency control (especially with large amounts of PV generation) will require an energy storage device to experience significant cycling, batteries in this type of service are not expected to last more than 6 to 8 years. This need to replace batteries more frequently for this type of service coupled with their higher maintenance cost will make them a less cost-effective solution than flywheels despite the battery's lower initial capital cost.

High Ramp Rate Firm Capacity for Frequency Control

New firm generating units with high ramp rate capability would help to maintain frequency as the energy from PV systems and wind vary. Of course, the generating unit would only be useful for this purpose when it is synchronized to the grid and producing power. The problem with using this technology during the day when PV output is maximized is that the firm generation will be required to run at a minimum load, which will take up load increment that the PV systems will need. So, this is not the best solution to control frequency during the daytime periods. That said, high ramp rate capability of new generation should not be ignored as a secondary benefit. It can be very useful during days when PV penetration does not preclude its use and at other times to help smooth out fluctuations caused by wind power generation.

THE EFFECTS OF DG-PV ON OUR GENERATION FLEET

As 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, we have begun to make changes to accommodate this increased DG-PV. Two options for handling this situation is to either run with fewer baseload units or add energy-shifting storage systems.

Reducing the Number of Baseload Units

We currently run a number of utility-owned and IPP units as baseload generation (see Table 13 on page 82). A baseload unit runs 24-hours a day, somewhere between its full and minimum output capabilities.

At least one baseload unit is commonly offline for maintenance. Our system operators then dispatch the remaining units as baseload units. This mode of operation is not only the most economical way to dispatch generating units, it results in sufficient amounts of reserves (both capacity and inertia) to manage unexpected generator trips.

If the baseload units do not provide enough capacity to meet the daytime load or the evening peaks, system operators dispatch additional firm generating units as necessary. Those additional cycling and peaker units are then turned off after the evening peak period is over. The minimum output total of the baseload units is typically lower than the minimum demand at any point throughout the day, including the hours between 2:00 AM and 4:00 AM when the load demand is normally at its lowest point. Therefore, there has not been a need to limit the number of baseload units running overnight.

Although, with the increasing amounts of DG-PV, that situation is rapidly changing.

With the anticipated levels of PV generation on O'ahu, the minimum load demand periods may soon change to occur in the middle of the afternoon between noon and 1:00 PM. These new minimum loads have, at times, been lower than the minimum output total of the available baseload units.

Table 14 summarizes the minimum generation for our baseload units. These Gross Minimum amounts are values as of 2015; they differ from the values listed in Table 13 because operational inefficiencies that have surfaced in the intervening years that resulted in lower output ratings.

Unit	Type	Gross Minimum	Net Minimum
Kahe 1	Baseload	25.0	22.5
Kahe 2	Baseload	25.0	22.7
Kahe 3*	Baseload	—	—
Kahe 4	Baseload	25.0	22.3
Kahe 5	Baseload	55.0	50.7
Kahe 6	Baseload	45.0	40.0
Waiau 7	Baseload	25.0	22.6
Waiau 8	Baseload	25.0	22.8
AES Hawai'i	Baseload	63.0	63.0
H-POWER (HRRV)	Baseload	23.0	23.0
Kalaeloa (KPLP)	Baseload	60.0	60.0
Totals	**—**	**371.0**	**349.6**

* Kahe 3 is currently unavailable for an extended period of time.

Table 14. Baseload Unit Minimum Generation

On afternoons with high DG-PV generation, demand could fall below the minimum output of our baseload units. When that happens, we have a few options: curtail utility-scale PV and wind; somehow reduce the number of dispatched baseload units (that is, turn off one or more of the baseload units); or install energy storage systems that can absorb midday energy and release it during peak demand.

We have, however, begun to devise other solutions to this problem. For details, refer to "The Effects of DG-PV on Operations" on page 90.

Grid Stability with Variable Renewables

The representation of PV output transitioning smoothly in a bell-shaped curve (Figure 20) is accurate for sunny days with no clouds. The reality is that PV output typically varies up and down as clouds pass by. Sometimes these variations can be significant as storms quickly roll in and out. The fact that DG-PV is dispersed throughout the island helps to somewhat smooth out the variability. However, the density of DG-PV has already reached levels where isolated cloud cover can result in relatively large spikes of generation output.

To counteract the variations, online firm generation must ramp up or down to maintain frequency within acceptable tolerances. The faster the outputs from the PV systems change, the faster firm generation must react. The existing steam units do have the capability to react to these changes. However, as more and more PV is installed, the required ramp rates may exceed the steam unit capability. Many of the available options for replacement generation have superior ramping capabilities and would provide more flexibility to react to large sudden changes in as-available generation output.

Sometimes the sudden downward variation from variable generation can be large enough to create a need to start idle firm generating units. To react to these situations, the idle 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 of our existing firm generation fleet.

THE EFFECTS OF DG-PV ON OPERATIONS

To keep a reliable system, we must plan for low PV generation days to meet the high demand. That means that on high PV generation days, we have excess spinning reserve on the system.

Because of three problems with DG-PV—its generation is unpredictable, the amount on the power gird is unknown and must be estimated, and it can't be curtailed—our system operators manage the grid as best as possible, albeit somewhat blindly. Their results have been exemplary despite the mounting challenges.

New tools, however, are emerging to help us predict with more accuracy, which we are implementing and using.

Getting Old Units to 'Dance'

One option for dealing with excessive amounts of DG-PV is to carry excessive reserves to cover high demand. This, however, does not make economic sense. Instead, Power Supply has been working on other ways to alter the performance of our utility-owned baseload generating unit.

Power Supply, however, is meeting this is a technical, management, and operational challenge. Our firm generation units, as a whole, are all over 40 years old. These units were designed to operate as the sole means of meeting demand.

But Power Supply is pushing them beyond the limits of how these units were designed to perform. They are effectively managing the risk, taking operator attention to a higher level, cross training personnel, performing a higher level of control testing—all on 40 and 50 year old equipment. This transformation was approached and accomplished systematically, with testing, learning, and training to virtually eliminate any increase in the risk of operating these units.

Our utility-owned firm generation was designed to operate in a range of 45%–95% of their gross capacity. For years (decades actually), we have operated these units in a range of 45%–80% of their gross capacity, on average. The increase in DG-PV means that we are now operating them in the 20%–60% range of gross capacity. This lower level of operation increases maintenance requirements, stresses the units, increases the possibilities of operating problems and trip events, and thus lowers the capacity factors used in generation planning.

We refer to Kahe 1–6 and Waiau 7–8 as reheat units. Reheat units are more efficient, which is why we operate them for baseload generation. Reheat units have a more complicated design for the water circuitry; they take a double pass to the boilers and the turbines thus increasing efficiency.

This complicated design, in turn, complicates our running them differently than they were designed to do. Nonetheless, that is exactly what we are doing.

Increased Operator Diligence and Expertise

PV generation is not the same every day; it's mostly unpredictable. How does a system operator predict which curve the day will bring? It is challenging and will become more so in the future with increasing amounts of non-curtailable PV. System operators must be prepared every day for something new.

When DG-PV penetration increases and generates at a high level, the demand curve at the beginning of the daily evening peak becomes steeper. This means the operators must ramp up generation faster and faster. This stretches the level of spinning reserve, and pushes the limits of the operation of our generating units.

The operational changes we are and have made to our firm generation fleet also challenges the day-to-day responsibilities of our system operators. Through extensive training, however, they have risen to the challenge.

Enhanced Low-Load Operation

Rather than turning off baseload generation to meet demand on high PV days, we are working toward reducing the minimum gross operating levels of these units. Reducing operating levels allows us to keep the unit running so that it can quickly respond to increases in demand.

Table 14 (page 89) lists the minimum gross generation that our baseload units were designed for. Our 90-MW baseload units (Kahe 1–4 and Waiau 7–8) have gross minimum operating levels of about 25 MW. We have been working on these units to reduce the gross operating minimums to 7 MW. This is called enhanced low-load operation. Even at these low levels, these units still provide inertia to the system.

Reducing the gross operating levels of these units is not a trivial accomplishment, and stretches the capability of these units. We have performed a lot of testing to better ensure their stability as well as their ability to operate at these low levels. Consequences have arisen. Current fixed speed pumps in these units, while operating well at reduced levels, compromise reliability and increase maintenance needs.

To run the units at 7 MW, we must pull burners in the boilers. On units with mechanical atomizers, we must pull more units than actually necessary to maintain low operating levels. This, however, is quite difficult and decreases the stability of the unit. Changing to steam atomization helps because it allows us to keep more burners in the boiler while maintaining the stability of the unit.

Because of the concept of sliding pressure, the pressure of the unit lowers as we reduce the load on a unit. As a result, the unit's response to a system disturbance will not be as robust. This is yet another complication that we are effectively handling.

Ramp Rates

Ramp rates for our baseload units are designed to run at about 3 MW a minute. We are currently pushing the ramp rate to 5 MW per minute so that the unit can respond more quickly to increases and fluctuations in demand. To run at these increased ramp rates, however, requires that the unit be running at full pressure. When operating at low pressures, these units can only attain a ramp rate of 2 MW a minute.

As with enhanced low-load operation, operating the units at a 5 MW per minute ramp rate is not a trivial accomplishment. To run at this ramp rate, we pull burners, then watch the flame closely to ensure the unit's stability. As might be expected, pulling burners, running at low operating levels, then ramping up quickly reduces stability. We fine tune the units to be able to run in this manner. We train staff on how to accomplish this safely and reliably.

We are still working on improving ramps rates, but the jury is out as to how effective we might be.

Cycling Units

One other option is to cycle these baseload units off and on. Since these units were not designed for cycling, this option creates much concern about reliably especially when combined with running the units at low load levels. This is purely a mechanical issue, as our staff have been fully trained to handle these conditions.

Kahe 1–4 and Waiau 7–8 need about two and half hours to come back online after being shut down. While we can plan to bring units back online in time for evening peak demand, there are inherent risks in these plans. First, the startup could take longer than expected (up to three and half hours or more), not online to meet the expected demand load, and thus create a generation shortfall. Second, if a unit experiences at problem during startup (for instance, during the second hour of startup), another unit must be started (if one is available), which again delays output to meet the expected demand load, and thus again creates a generation shortfall.

So while these units can be cycled, there are challenges and risks that must be overcome. Cycling these units also increases the wear and tear on the units, as well as require more maintenance. And again, this cycling creates more work and demands more attention from our staff.

One other point. Cycling the larger baseload units—Kahe 5 and Kahe 6—is not feasible because of their size and with increased problems complying with environmental regulations.

Evolving Dispatch of Our Cycling Units

The effect on our cycling (non-reheat) units has already been very noticeable. The average cycling unit capacity factor has dropped from 16.6% in 2011 to 10.2% in 2013. If the lowering daytime demand trend continues (as forecast in Figure 20), we will no longer need to run our cycling units for most of the day (unless enough baseload are not available).

We have historically run these cycling units approximately 15 hours a day. Now, we regard them as short-term cycling units, running them approximately 5 hours a day. At some point, we will only need them as peaking units.

The Increasing Challenges of MATS Compliance

Stretching the operation of our baseload units has complicated our ability to comply with MATS requirements.

Particular Matter

Enhanced low-load operation complicates our ability to comply with MATS requirements. Particulate matter emissions is higher at low loads. We can measure particulate matter a couple of ways.

One method is to measure all the units once a quarter. We then take problematic units with high levels of particulate matter offline, and wash them. Because of the tight coupling between capacity and demand, this sudden removal can present immediate problems. This situation has the possibility of forcing us to increase capacity because our outage rate will be higher.

The other measurement methods is to install particulate matter continuous equipment monitoring systems. As the name implies, these systems continuously measure particulate matter levels. These systems average the low load measurements with high load measurements, meaning that the computed average is higher that the actual level of particulate matter in the unit. Because of these measurements, we would be taking offline and washing units more frequently, and before they actually needed the washing.

Air Preheaters

Operating at low levels results in the air preheaters for the baseload units become fouled more quickly. In more exact terms, they become plugged up. As a result, the unit begins having back pressure issues. Once plugged, they have to be cleaned. Running units at low level increases the number of cleanings, and thus reduces the availability of the unit.

The air preheaters actually decay quite quickly once they start getting fouled. Fouling limits the output of the unit. Units run with fouled air preheaters must be derated.

We have been having some success with washing the air preheaters while the unit is online. This helps with availability.

We are also considering changing the fuel mix to 70% LSFO and 30% diesel to slow down the fouling. This fuel adjustment can reduce the amount of maintenance, albeit slightly.

Liquefied Natural Gas (LNG)

Sulfur in the fuel creates particulate matter and causes the air preheaters to foul.

Switching to LNG eliminates these MATS compliance problem, even at low operating levels, because LNG does not contain sulfur. This would keep our baseload units running at full output with a lot less maintenance issues.

RELIABILITY AND AVAILABILITY

Short-Term Reliability Issues

All of our hard work and expertise and dedication is paying off. Reliability remains high.

Through our efforts and with a wealth of individual intervention, we have made relatively inflexible units flexible. Three of the six 90 MW baseload units—Kahe 1, Kahe 2, and Waiau 8—can run simultaneously at 7 MW each when necessary to reduce spinning reserve. We dispatch these units at these low levels when daytime DG-PV generation and nighttime wind generation are both high. When daytime DG-PV generation and nighttime wind generation are both low, we must go the other way and run the units at high levels. Because this variable renewable generation is unpredictable and can change rapidly, we must be prepared for the full spectrum of operation every minute of every day.

Pushing the limits of the design of units increases the possibility of trip events, not only when they are being constantly cycled, but especially when the units are turned on and off.

We must guard against getting into a habit of routine unit washings in an effort to keep output at their highest levels. Once again, this puts additional pressure on staff to be cognizant of this pattern and avoid it while still keeping output at top levels.

To comply with MATS requirements, our maintenance plans for future years contain significantly more outages. This required stepped-up maintenance results in increased loss of availability. In addition, cycling units, running them at enhanced low-load operation, and increasing ramp rates all increase maintenance needs.

In sum, all this extra maintenance and cleanings means that the units operate with lower capacity factors, a fact that must be considered in generation planning.

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.

7. Potential for Future Generation Shortfalls

After these recent outages, a key question to resolve is simply this: what is the potential for generation shortfalls in the future?

Central to this question are a number of questions: Is our projected generation adequate for the immediate future? Will a future outage fall within our Capacity Planning Criteria and, as such, comply with our loss-of-load probability criteria? Does our planning include other factors that would mitigate future shortfalls?

What follows is a discussion of the options available to us to minimize future generation shortfalls. Some help in small ways, others help avoid contingency situations, and others outline fundamental changes.

No matter which path we choose, we must continually seek an acceptable balance between reliability and cost.

ADEQUACY OF SUPPLY (AOS) 2015 SUMMARY

Our Adequacy of Supply (AOS) reports from both 2014[12] and 2015[13] both indicate sufficient generation for reasonably expected demand and for emergencies. (For specific amounts, see Table 8 on page 69.) We based this conclusion by analyzing forecasts for the upcoming year, both of which show slightly increasing annual peak demand.

[12] Hawaiian Electric Adequacy of Supply 2014 (filed 30 January 2015): http://puc.hawaii.gov/wp-content/uploads/2015/04/Adequacy-of-Supply-HECO-2014.pdf

[13] Hawaiian Electric Adequacy of Supply 2014 (filed 11 April 2014): http://puc.hawaii.gov/wp-content/uploads/2015/04/Adequacy-of-Supply-HECO-2015.pdf

Our Adequacy of Supply 2015 report stated that we could experience a generation shortfall in the first quarter of 2015. The report also indicated that we could experience a reserve capacity shortfall starting in 2017 when we anticipate deactivating Waiau 3 and Waiau 4. If this potential generation shortfall start to appear as a reality as 2017 gets closer, we will take appropriate actions to ensure an adequate supply. The easiest step would be to delay deactivating these two units.

LOSS-OF-LOAD PROBABILITY (LOLP) CRITERIA

Our current Capacity Planning Criteria is based on a loss-of-load probability factor of 4½ years per day. We have relied on this standard for decades. (See "Appendix F. Loss of Load Probability (LOLP) Explanation" on page 142 for a brief historical background.)

Interconnected utilities (such as those on the mainland) use a LOLP factor of ten years per day—a higher reliability standard. We use the 4½ years per day criteria mainly because we are an isolated utility, as do many other isolated utilities.

Planning Uncertainty

One method of lowering the potential of future generation shortfalls would be to revise our Capacity Planning Criteria to match those of interconnected utilities. We must consider a number of quickly-changing parameters, such as changes in peak demand and the reliability (and thus the availability) of our generating units.

Meeting the ten years per day requirements requires a number of changes in our current operating structure: increased amounts of reserve generation, more thermal generation capacity, higher reserve margins, and increased levels of production operation and maintenance. All of these changes would increase costs.

While these changes would not eliminate future outages, they would potentially lower their possibility. Such a measure of conservatism must recognize that uncertainties undoubtedly exist, and that we would have to effectively deal with these uncertainties as they arise. In other words, not matter what our LOLP is, we still must deal with the vagaries of our system.

Deactivated Generation Resources

Additional generation can mitigate future generation shortfalls, but do we need it?

If such capacity is needed, we have a few options: add more thermal generation, reactivate the Honolulu generating facility, and delay the deactivation of two units from the Waiau generating facility. Reactivating Honolulu 8 and Honolulu 9 would incur a $5–10 million dollar annual maintenance cost. Had these units been active, the January 12 rolling outages would have still occurred, although with much less severity and shorter duration.

All of these options, of course, are openly counter of the overall exhortation for increasing amounts of renewable generation.

OPTIONS POTENTIALLY MITIGATING ANOTHER OUTAGE

A number of options could potentially mitigate future outages, or if they do occur, their duration and reach (in other words, how long they last and the number of customers they affect) would be diminished. While each of these options has their appeal, they are not without their limitations.

Schofield Generating System

In Docket No. 2014—0113, Hawaiian Electric applied for approval to install approximately 50 MW of utility-owned and operated, firm, dispatchable generation on the Schofield Barracks Army facility in central O'ahu. This additional generation will improve the reliability and resiliency of our electric power grid as well as enable the integration of more variable generation renewable. This installation would also add a measure of energy security to the Army installation.

We anticipate the project going online in 2018. The additional 50 MW of firm generation might alleviate the projected shortfall in reserve capacity in that year and beyond. In addition, the installation would offset, somewhat, the loss of generation caused by deactivating Waiau 3 and Waiau 4.

More firm generation increases system reliability and, as a result, minimizes the potential for future generation shortfall.

Replacement Firm Generation

Replacing large existing firm generation with smaller firm generation could potentially improve reliability. For example, replacing an 180 MW unit with two 90 MW units has a number of benefits. Compared to a large single unit, new, smaller units would have:

- Lower EFORd ratings.
- Shorter and more flexible maintenance periods.
- On average, experience fewer outages, thus higher availability and improved reliability.

Higher availability better meets our LOLP reliability criteria, and thus reduces the potential for generation shortfalls.

Battery Energy Storage System (BESS) Resources

Hawaiian Electric intend to use energy storage as part of a portfolio of resources and methods to increase grid reliability. Energy storage has the potential to smooth intermittent generation from renewable energy and improve overall grid reliability.

Our Power Supply Improvement Plan (PSIP), filed in 2014, described a preferred plan that included the installation of two BESS units on O'ahu: a 200 MW BESS installed in 2017 for contingency reserve, and a 100 MW BESS installed in 2022 for regulating reserve. Each would help stabilize system frequency during a contingency event, and thus contribute to grid reliability.

The 200 MW BESS, providing contingency reserve, is designed to provide energy to the grid for approximately 30 minutes. The BESS would immediately inject power into the grid to help restore the balance between generation and load during a contingency event. This would occur when a large generating unit trips offline, and the resultant low frequency causes a large amount of DG-PV to simultaneously trip offline—exactly the circumstances the led to the 12 January 2015 rolling outages.

The 100 MW BESS would provide regulating reserve. It would absorb power from, or inject power into, the grid to help stabilize system frequency. This frequency stabilization enables the integration of increased amounts of DG-PV onto the power grid, which avoids our starting firm generation to meet demand.

Both of the BESS resources can help mitigate the potential for future generation shortfalls, although only for short durations (such than one hour).

Customer-Sited Emergency Generators

Numerous customers already employ emergency generators located on their properties. For example, the Queen's Medical Center owns an emergency generator comprised of four 2.25 MW diesel engines. With over 50,000 gallons of fuel storage, this generator can run for a number of days.

When experiencing a contingency event (such as a power outage or system emergency), we could ask these customers to reduce load by starting their emergency generators to supply their power and disconnect from the grid. These customer-sited emergency generators could lessen the severity and duration of relatively small generation shortfalls.

About 17–18 MW of generation was disconnected for different time periods during the January 12, 2015 trip event. Had all customer-site emergency generators been activated, this 17–18 MW shortfall would have been alleviated.

The Honolulu Airport dispatchable standby generation (DSG) project is yet another example of customer-sited generation. When this project is installed, we will be able to rely on its 8 MW of quick-starting generation to lessen a generation shortfall.

Demand Response (DR)

Demand Response (DR) programs can mitigate the potential of future generation shortfalls. DR programs give grid operators more flexibility when balancing supply and demand. DR can contribute regulating reserve, contingency reserve, and non-spinning reserve.

Dispatching a DR program can temporarily decrease demand, during certain periods of the day to deal with various system events, and thus eliminate or reduce customer impact. When the event ends, these DR loads are returned to the system.

Customers receive incentives for enrolling in one of three DR programs. The Residential Direct Load Control (RDLC) program enrolls about 14.7 MW; the Commercial and Industrial Direct Load Control (CIDLC) program enrolls about 12.7 MW; and the Fast DR program enrolls about 7.0 MW. Total enrollment is approximately 34.4 MW. This, however, is only an estimate because the amount is too difficult to measure.

These three programs are designed for one-hour dispatch. System operators, however, can dispatch these programs a number of times each day. While there are no firm limitations regarding the dispatch of DR programs, multiple dispatches can lower customer satisfaction. This dissatisfaction could then cause customers to leave the programs.

Other circumstances can lead to the DR programs being less effective. For instance, during the January 12, 2015 trip event, we issued a plea to conserve energy. The amount of generation available from any DR-enrolled customer voluntarily conserving energy would then be reduced.

Season, time of day, and other variables impact the performance of a DR program. As such, seldom is the entire 34.4 MW of enrolled capacity available for dispatch. in DR programs. A Demand Response Management System (DRMS) would enable System Operations to accurately forecast loads available for dispatch. DR loads broken down into groups for multiple dispatch could also aid system reliability. The two-way technology provided by a Smart Grid will help garner more accurate information.

These operational limitations, then, must be considered when assessing benefits, especially for system reliability. If these DR programs can meet these requirements, however, then using them judiciously could reduce system demand to levels that would increase system reliability.

Smart Grid Technology and Implementation

Smart Grid, while not providing any capacity, would enhance DR dispatch and thus benefit the operation and reliability power grid. Numerous Smart Grid solutions combine to enable these benefits.

To be most effective for grid reliability, DR programs would need a DRMS. System operators could then manually dispatch DR programs through the DRMS or an Energy Management System (EMS) could automatically dispatch DR. An Advanced Distribution Management System (ADMS), integrated into the DRMS, would provide system operators with a wealth of information about how the power grid is operating, and thus provide them with the tools to better respond to contingency events.

AMI meters facilitate a two-way communication between in-home devices and our central offices, enabling DR to be automatically dispatched as needed. This two-way communication technology provides available loads that we can reduce at any given moment. (One-way technology does not provide this level of information.) The two-way communication network provides an accurate picture of the system, thus giving system operators the confidence to potentially dispatch larger amounts of DR.

The AMI mesh network connected across all devices would facilitate this communication. This mesh network creates a reliable communication web because it contains devices that we select, install, and maintain, rather than relying on the happenstance devices that customers might install on their own.

A Customer Facing Solution (CFS) directly connects customers to the grid communications network. Then, through a text message, email, or web portal broadcast, the AMI would tell customers that we are dispatching DR. In addition, a CFS makes it easier for customer to enroll in and manage DR programs, thus making greater amounts of generation available to system operators. We can even use the CFS interface to communicate news to customers, such as appeals for energy conservation.

A Smart Grid-based critical peak pricing program would give customers an incentive—a lower cost per kWh—to shift usage from peak periods to times of less demand. Other time-based pricing programs "shave the peak" and "fill the valley" of the daily load demand profile, flattening (albeit slightly) the daily demand curve.

Community or substation battery storage, dispatched via SCADA, could also be employed to enhance grid reliability.

A future Smart Grid solution—customer-sited battery energy storage systems—could become a reality sometime in the next decade. We could create a DR program allowing us to discharge the batter energy when we need generation during an energy shortfall.

Ultimately, Smart Grid can make our current DR programs more robust. Smart Grid gives us access to more information from distribution to delivery, increasing the visibility and transparency of our power grid. From this, we can create programs that appeal to customers while maintaining grid stability and increasing reliability. These programs benefit customers, and the power grid.

MATS (Mercury and Air Toxics Standards) Compliance

Hawaiian Electric must now comply with MATS. We are currently determining the exact actions, maintenance procedures, and periodicity necessary to comply. For instance, can we comply by burning a cleaner fuel, or by washing certain boiler components (such as air preheaters) more frequently? Increasing unit washings causes a cascading series of events: more frequent planned outages results in higher EFORd rating for the unit, meaning less available generation, thus raising our LOLP which could raise the probability of generation shortfalls.

We are still performing unit tests and analyzing reliability issues to minimize—if not eliminate—the effects of MATS compliance on system reliability.

Independent Power Producer Contingencies

One IPP unit presents contingency issues on the O'ahu power grid: AES Hawai'i.

AES, the largest and lowest cost generating unit on O'ahu at 180 MW net, almost always runs at full output during the day to meet daily demand. (By comparison, the next largest units are Kahe 5 and Kahe 6, both rated at about 134 MW net.)

Daytime loads can drop to about 740 MW when DG-PV is generating at a high level; evening loads (between 5:00 PM and 9:00 PM) typically range from 950 MW to 1,100 MW.

When AES trips offline—like it did on January 12, 2015—the power grid immediately loses between 18% to 24% of its total generation. As a result, system frequency plummets more than if any other unit tripped offline. The trip also causes a large amount of DG-PV to trip offline, further exacerbating the event.

We are not starting our cycling units on days with high DG-PV generation. As a result, fewer units are online to provide the inertia that helps mitigate the frequency drop. Arresting this frequency drop, reversing it, and stabilizing it becomes more difficult. As a result, several blocks of load are programmed to shed, and bringing that load back online takes more time.

Large amounts of load shedding not only occurred on January 12, 2015, but also on April 2, 2013 and on June 9, 2014 when AES tripped offline. These events indicate that the AES unit is too large for the O‘ahu power grid.

We dispatch AES at the highest possible level to reduce operating costs. We could run AES at lower levels to reduce large amounts of load shedding when it trips. This, however, would require us to replace the lower generation with higher cost generation. Thus, running AES at top level increases the likely hood of future generation shortfalls.

Underfrequency Load Shedding

December 26, 2008 saw and island-wide outage—a total blackout. As a consequence, we developed, adopted, and implemented more aggressive underfrequency load shedding schemes to minimize the potential of island-wide outages in the future. These schemes shed load blocks at higher system frequencies to more quickly arrest frequency decay.

These load shedding schemes result in 10–20% of the customers to lose power for each block shed. Customers remain disconnected until system frequency stabilizes and rebounds when we can safely reconnect them.

The load shedding schemes are a trade-off. While a broader group of customers might lose power, these outages are generally shorter and more contained, and the potential for another island-wide outage is significantly reduced.

While our current load shedding schemes do not lower the potential for generation shortfalls, they do contain the duration and breadth of outages.

Grid Modernization

The O'ahu power grid has shifted from a utility-owned, central-station-dominant energy provider to one composed of independent power producers, ranging from small customer-sited DG-PV to larger, independent developer-based projects. The electrical grid has also experienced a shift from firm generation to one that includes an increasing amount of variable renewable generating resources. This increase in renewable generation and decrease in fossil-fuel generation has enabled Hawaiian Electric to meet Renewable Portfolio Standards early while decreasing emissions.

The electric grid must adapt to this changing resource mix. The design of the current electric grid is based on central station delivery of energy to its customers. The advent of DG-PV and other renewable resource, however, compels us to modernize our grid and our generation fleet to accommodate this shift.

This modernization must happen for both supply-side generation as well as for transmission and distribution.

Our existing generation units have too many limitations: lower response times relative to ramp rate and droop; must-run designations; minimum operation levels that restrict accepting higher levels of variable generation; as well as others. The O'ahu grid needs new firm generating units with greater operational flexibility. As these news units are added, we can deactivate or decommission existing generation.

These newer generation units will be better equipped to:

- Counteract fluctuations in increasing levels of variable renewable generation.
- Cycle on and off quickly.
- Provide firm, reliable generation when dispatched on short notice.
- Improve system-wide efficiency.
- Burn the most cost effective fuel available (fuel flexibility).
- Reduce must-run generation.
- Contribute to system security.

Grid modernization also requires energy storage, such as a utility-scale battery energy storage system (BESS). This type of BESS:

- Enable us to better control grid operations and manage variable generation across the entire island.
- Contribute to system security and reliability.
- Increase variable generation when coupled with quick-starting firm generation.

Deactivating or reducing the generation from our thermal units allows for more renewable energy to satisfy demand. The BESS could be relied on for reserve electricity to counteract the fluctuations from these renewable resources. Of course, the BESS cannot always completely replace the vagaries of variable renewables simply because, at time, its generation drops to near zero. Thus, we would still need quick-starting thermal generation to meet demand and ensure the reliability of the grid.

As outlined in the PSIP, our transmission and distribution system must also be modernized. This modernization would include a full suite of technologies and capabilities necessary for operating: data acquisition capabilities, controlling devices, telecommunications, and control systems. Smart Grid can bring much needed modernization, including Advanced Metering Infrastructure (AMI) with its two-way communications; an Advanced Distribution Management System (ADMS) and Energy Management System (EMS) together with the necessary implementation components; Volt-VAR Optimization (VVO); more robust Demand Response programs; better control (including curtailment and dispatch) of distributed generation (DG); adaptive relaying (dynamic load shedding); transformer monitoring; and potentially other advanced analytics, reporting, and monitoring capabilities.

Such is the vision for the power grid of the future. It would require enormous effort, critical research, detailed analysis, careful installation, and decisive external support to ensure the smoothest transition—all the while delivering a secure and reliable electric power grid.

This full scope of grid modernization components, together with new quick-starting generation, would considerably enhance our system reliability and lower the potential for future generation shortfalls.

Distributed Generation Photovoltaics and Customer-Side Energy Storage

While unit trips can occur any time, generation shortfalls almost always occur during evening peak: between 5:00 PM and 9:00 PM, with a higher demand between 6:00 PM and 8:00 PM. DG-PV generates most of its power between 10:00 AM and 2:00 PM. Because it's dark outside for most of evening peak, DG-PV does not—in fact, cannot—generate power.

As such, DG-PV does not, and cannot, help alleviate a potential outage for the vast majority of our customers.

DG-PV did not help serve peak demand during the rolling outages on January 12, 2015. Indeed, a large amount of DG-PV (about 30 MW) tripped offline immediately following the AES trip.

Individual customers with high-cost battery storage units might be helped, but the size of the unit limits its contribution to a generation shortfall.

DG-PV installation can be coupled with either a "non-export" or a "smart export" a battery energy storage system. Each system stores power generated by the DG-PV system during the day—but each in a different way—to be discharged at other times of the day.

A non-export battery energy storage system stores the power produced by the DG-PV system in excess of a customer's load. This coupled system has less circuit penetration than does DG-PV alone.

A smart export battery energy storage systems stores all the power produced by the PV system; none serves the customer's load. This coupled system has no circuit penetration because the customer's load remains on the circuit. Smart export systems can help reduce curtailment from lower cost, utility-scale renewable resources during the middle of the day for limited amounts of load.

Currently, neither type of battery-coupled system is on the system. When integrated into the system, they could help forestall the kind of rolling outages experienced on January 12, 2015. Their impact depends on the extent of the generation shortfall, the number of battery-coupled systems on the grid, and the aggregate amount of power they stored during the day. Unless they are designed to operate independent of the grid, the impact of these battery-coupled systems on switched-off circuits would be nonexistent.

We do not anticipate these battery-coupled systems being part of our electric grid anytime soon. Until such time, DG-PV ability to help mitigate a generation shortfall is also nonexistent.

NEW CONTRACTUAL TERMS FOR FUTURE POWER PURCHASE AGREEMENTS

Traditional power purchase agreements (PPAs) pay independent power producers (IPPs) on a combination of available firm capacity and the amount of energy delivered to the power grid. Such an agreement behooves IPPs to make their units available as much as possible.

These agreements evaluate Equivalent Availability Factors (EAFs) and EFORd numbers every contract year. The EAFs tend to decline and EFORd numbers tend to increase as IPP units age if necessary maintenance was foregone in an effort to keep availability high and maximize payments (a situation potentially exacerbated near the end of a PPA).

To counter this situation, future PPAs must contain incentives and sanctions (such as financial penalties for excessive unit trips or higher than expected EFORd numbers) to ensure proper maintenance together with high availability.

8. Conclusions and Recommendations

After analyzing the information garnered from the trip event and resultant outages, assessing our planning guidelines, and considering the evolving composition of our electric power grid, we have reached a number of conclusions. From these conclusions, we offer a number of cogent recommendations to be thoughtfully considered.

CONCLUSIONS

Despite the rolling outages on 12 January 2015, the Hawaiian Electric power grid has surpassed the expectations stated in our Capacity Planning Criteria. Our planning is based on a reliability guidelines of one outage day every 4½ years; the last such outage occurred on 26 December 2008, over six years ago.

Increasing amounts of DG-PV make the grid more difficult to manage and maintain its stability, a situation that has occurred much quicker than we anticipated. In 2013, we projected the affects of DG-PV on our daily load curve. The resultant load curve that we predicted for 2017 is already happening today.

At any given moment, we can only estimate the amount of DG-PV. We need to to know this amount precisely.

DG-PV can't be controlled nor curtailed. This needs to change for two main reasons: to better maintain system stability and reliability, and to be able to dispatch lower-cost generation when necessary (DG-PV is the most expensive electricity on our power grid).

Increasing amounts of DG-PV means less firm generation online, which means system inertia is lower making it more difficult to stabilize a contingency.

Increasing amounts of DG-PV make AES (the lowest cost electricity on the power grid) an ever larger percentage of firm generation, making it more and more difficult to respond to future AES trips.

On high DG-PV generation days, we are not turning on firm generation units in the afternoon. This means the system has less spinning reserve to respond to a contingency. This situation also increases the chances of not being able to start enough firm generation to meet evening peak (when DG-PV stops generating). To better respond to this situation, we need to begin replacing some units with new quick-starting units.

DG-PV tripped offline almost immediately after AES fully tripped offline because of the IEEE 1547 trip settings. Had this not happened, the afternoon UFLS would have been avoided.

When DG-PV tripped offline following the AES full trip, our UFLS schemes didn't take this generation loss into consideration because DG-PV can't be 'seen'. Thus, the contingency looked smaller than it actually was.

Even though we experienced brief outages in the afternoon, our UFLS schemes performed as expected.

Sufficient spinning reserve was available when AES fully tripped offline, however, the contingency still required one block of UFLS to stabilize frequency. This shouldn't have been necessary.

Our reserve margin needs to be increased from 20% to 30% to better plan for meeting future contingencies.

Power Supply is getting more our of our firm generation units than most industry professionals thought possible.

Power Supply is performing wonders with our firm generation units to get them to meet demand. These modifications (enhanced low-load operation, increased ramp rates, and cycling) most likely will increase maintenance and age the units faster.

High wind generation could have avoided the rolling outages, but it was only generating less than 5% of its full capacity. This demonstrates that wind cannot be counted on to overcome a generation shortfall.

As a result of the trip event, we changed our generation conditions and contingency plans. How well these new guidelines will perform during the next major contingency still need to be assessed.

Consideration should be given to changing our LOLP reliability guidelines from 4½ year per day to 6 years per day.

Our DR programs helped reduce load during the afternoon and evening events, making the outages less severe.

An airport DSG would have spared about 8,000 customers from the evening outage.

We must carefully consider whether deactivating Waiau units at the end of 2016 is prudent. Their deactivation cast some doubt on meeting our reliability guideline and LOLP for 2017 and beyond.

We have to carefully assess whether the 10% that we assigned as the capacity value of wind is workable.

We must communicate better about future outages by earlier notification and more specific outage locations. Perhaps text messaging and emailing could help achieve this.

In general, customers responded well to our use of social media channels (Facebook, Google+, and Twitter) to communicate information about the trip event and rolling outages.

Switching to LNG will drastically reduce unit maintenance necessary for MATS compliance, increasing the availability of our firm generation units.

The inertial response from a 130 MW battery energy storage system (BESS) would have prevented UFLS (had one been installed).

BESS units could provide both regulating reserve and contingency reserve, helping to mitigate the potential for future generation shortfalls, although only for short durations (such than one hour).

RECOMMENDATIONS

Increasing amounts of DG-PV compromise system stability. As a result, we recommend considering the following initiatives to mitigate system impacts attributed to another AES trip:

- Simultaneously trip the AES generator and its auxiliary loads from the power grid for turbine trips. (We are investigating the feasibility of making this change.)
- Add a battery energy storage system (BESS) or fast-response reserves.
- Reduce the amount of Legacy PV if energy storage is not feasible.
- Increase system inertia (run more synchronous generators) and evaluate the current UFLS scheme.

We also recommend considering the following initiatives to improve future unit trip investigations:

- Install Tesla recorders at AES, Kalaeloa, and H-POWER.
- Add turbine speed, governor valve position, and turbine first stage pressure to the existing Hawaiian Electric Tesla recorders.
- Improve the monitoring of DG-PV output, specifically Legacy PV.
- Improve the PSSE dynamic models.
- Improve the real-time load monitoring of RDLC and CIDLC to validate their performance during system contingency events.

Appendices

There are three appendices in this report that provide supporting information.

Appendix A. Generation Conditions and Contingency Plans: Details the severity level that describes the conditions for assessing an outage, and outlines the steps for handling each outage level.

Appendix B. Daily Generation Reports: Compares the daily generation reports for the two days of the outage: January 12, 2015 and January 13, 2015.

Appendix C. Outage Notification List: Lists the Hawaiian Electric personnel, together with their job title, who are notified in the event of an outage.

Appendix D. Reserve Margin Calculations: Explains how we calculate current and future (the next five years) reserve margins.

Appendix E. Unit EFORd Explanations: Explains how Hawaiian Electric determines the Equivalent Demand Forced Outage Rate (EFORd) for its generation units.

Appendix F. Loss of Load Probability (LOLP) Explanation: Explains the origins of how we calculate the LOLP used in our Capacity Planning Criteria.

Appendix G. Generator Inertia Constant H Values: Lists the generator constant H for the generation units on the Hawaiian Electric power grid.

Appendix H. News Releases: Reproduces our news releases issued to the media.

Appendix I. Social Media Postings: Contains our social media posts, and samples of the responses we received from our customers.

A. GENERATION CONDITIONS AND CONTINGENCY PLANS

A set of guidelines govern the daily operation of the Hawaiian Electric power grid. These guidelines consists of a set of six generation conditions, each of which identifies the current operating state of the power grid. There are two generation conditions for normal operation, and four for risk conditions. The System Operations department (or SysOps) applies these guidelines throughout the day to accurately identify the current reliability—and risk—of the power grid.

A set of six contingency plans is coupled to these six generation conditions. In other words, for each generation condition, there is a corresponding contingency plan. Each contingency plan is a set of actions that can be implemented as conditions and circumstances on the power grid require.

The Incident Commander (a high ranking, experienced member of SysOps), together with department leaders (such as the Manager and the Vice President of System Operations), assess the current condition of the power grid and its relevant risks. Uncertainty of system load and the amount of variable generation (mainly DG-PV) complicate these assessments. Company decision makers weigh a number of factors in their assessments. Chief among these factors: protecting company equipment and assets, and ensuring the safety of company personnel and the general public.

Based on their assessment, decision makers assign the generation condition that best represents the current state of the power grid and decide how, when, and which actions to implement in the corresponding contingency plan.

The contingency plans for certain risk conditions either advise or require notifying certain groups of customers or all customers. Customer groups include major commercial customers, large customers, government agencies, the media, and residential customers. The Vice President of System Operations (or a designated alternate) must first approve any public notification.

SysOps revised and updated these Generation Conditions and Contingency Plan guidelines following the outage on 12–13 January 2015. Overall, the new guidelines are more detailed and change the risk assessment so that the contingency plans are acted upon sooner.

Generation Condition Guidelines

Revision 16 of the our Generation Condition guidelines was in effect during the outage on 12–13 January 2015.

Generation Conditions, Revision 16

Generation Condition	XOSR*	Risk of Not Serving Load
ALPHA	XOSR ≥ 0 MW	Normal operations Offline reserve capacity available
BETA	XOSR ≥ 0 MW	No units in reserve
1	0 MW > XOSR ≥ –40 MW	AES, Kalaeloa Plant, K5, or K6 outage
2	–40 MW > XOSR ≥ –90 MW	Any reheat or Kalaeloa CT outage
3	–90 MW > XOSR ≥ –180 MW	Any unit outage
4	XOSR < –180 MW	Manual load shed

Table 15. Generation Condition (Revision 16) Guidelines

Generation Conditions, Revision 17c

Following the outage on 12–13 January 2015, SysOps refined our operating guidelines, creating revision 17c of the Generation Conditions.

Generation Condition	XOSR*	OSR*	Risk of Not Serving Load
ALPHA	XOSR ≥ 0 MW	Offline reserves available	Normal operations Offline reserve capacity available
BETA	XOSR ≥ 0 MW	No offline reserves	No units in reserve†
1‡	XOSR < 0 MW	90 MW ≤ OSR < 180 MW	AES, Kalaeloa Plant/CT (2 CT operation), K5, or K6 outage
2‡	XOSR < 0 MW	60 MW ≤ OSR < 90 MW	Any reheat or Kalaeloa Plant (1 CT operation) outage
3‡	XOSR < 0 MW	0 MW ≤ OSR < 60 MW	Any unit outage
4	XOSR < 0 MW	OSR < 0 MW	Manual load shed

Table 16. Generation Condition (Revision 17c) Guidelines

Notes:
* The calculations for spinning reserve, XOSR (Excess Operating Spinning Reserve) and OSR (Operating Spinning Reserve), exclude any observable variable generation.
† Waiau 3 and Waiau 4 are considered *unavailable* unless they are fully staffed.
‡ How Generation Conditions 1, 2, and 3 are applied depends on the capacity of the "largest unit".

Changes Made to the Generation Conditions Following the Outage

SysOps made the following changes to revision 16, resulting in guidelines updated in Revision 17c:

- Simplified the Excess Operating Spinning Reserve (XOSR) conditions for MW outage levels.
- Added a new set of conditions, Operating Spinning Reserve (OSR), that contained detailed conditions for MW outage levels.
- Added an additional risk consideration for the BETA generation condition.
- Added additional risk considerations for generation conditions 1, 2, and 3.
- Expanded the list of generation units that affect the risk of not serving the load for Generation Conditions 1 and 2.

Generation Contingency Plans

Contingency Plan actions vary according to the generation condition. During the ALPHA generation condition (normal operations), SysOps plans and performs routine maintenance and repairs on all company-owned generation units so as to maintain the reliability of the power grid. Maintenance is never scheduled when it might potentially put system reliability at risk.

During BETA, no maintenance is performed. During any of the four risk generation conditions (1, 2, 3, and 4), the Incident Commander implements the contingency plan actions that are most appropriate for restoring a reliable and stable grid.

Contingency Plans, Revision 16

Generation Condition	XOSR	Risk	Contingency Plan
ALPHA	XOSR ≥ 0 MW	Offline reserve capacity available. One unit in reserve offline.	1. *Normal Operations.* System Operation coordinates all planned maintenance to be performed.
BETA	XOSR ≥ 0 MW	All units online. No units in reserve	1. *Normal Operations.* Before conditions get to next level, all unit blocks should be reviewed and returned if possible. No unnecessary maintenance will be performed.
1	0 MW > XOSR ≥ –40 MW	AES, Kalaeloa Plant, K5, or K6 outage	1. *Risk duration of less than two hours:* a. Ask Kalaeloa for additional energy. 2. *Risk duration of greater than two hours:* a. Ask Kalaeloa and AES for additional energy. b. Consider informing major commercial customers of the situation (no conservation requested). c. Consider informing the appropriate government agencies as needed.
2	–40 MW > XOSR ≥ –90 MW	Any reheat or Kalaeloa CT outage	1. *Risk duration of less than two hours:* a. Consider informing major commercial customers of situation (no conservation requested). b. Consider informing government agencies as needed. c. Ask Kalaeloa and AES for additional energy. d. Ask H-POWER for additional energy. 2. *Risk duration of greater than two hours:* a. Implement all of line 1 action items (a through d above) in General Condition 2. b. Consider asking for voluntary conservation from residential customers via the media (providing a two-hour lead time).

Generation Condition	XOSR	Risk	Contingency Plan
3	–90 MW > XOSR ≥ –180 MW	Any unit outage	1. *Risk duration of less than two hours:* a. Consider voluntary conservation from large commercial customers. b. Ask Kalaeloa and AES for additional energy. c. Ask H-POWER for additional energy. d. Inform government agencies as needed. e. Execute Residential Direct Load Control (RDLC) program. 2. *Risk duration of greater than two hours:* a. Implement all of line 1 action items (a through e above) in General Condition 3. b. Notify Rider I and Commercial Direct Load Control (CDLC) program customers of possible demand response action of the possibility of executing both programs. c. Consider operating Waiau CTs at peak or peak-reserve temperature. d. Consider operating Hawaiian Electric reheat units at top heater out and overpressure.
4	XOSR < –180 MW	Manual load shed	1. *Any risk duration* a. Implement all of items in General Condition 3. b. Plan and execute rolling blackouts; provide a one-hour notice if possible. c. If frequency is dropping below 59.0 Hz, consider manually shedding load. d. Ask all customers to run their emergency generators.

Table 17. Generation Contingency Plans (Revision 16)

Contingency Plans, Revision 17c

SysOps updated the contingency plans related to the six generation conditions after the outage on 12–13 January 2015, resulting in revision 17c.

Generation Condition	XOSR	OSR	Risk	Contingency Plan
ALPHA	XOSR ≥ 0 MW	Offline reserves available	Normal operation; offline reserve capacity available	1. *Normal Operations.* Planned maintenance shall maintain ALPHA condition. Unplanned outages to be considered based on risk conditions.
BETA	XOSR ≥ 0 MW	No offline reserves	No units in reserve	1. *Normal Operations.* Before conditions get to next level, all unit blocks should be reviewed and returned if possible. No non-critical or routine maintenance will be performed.

Generation Condition	XOSR	OSR	Risk	Contingency Plan
1	XOSR < 0 MW	90 MW < OSR < 180 MW	AES, Kalaeloa Plant/CT (2 CT operation), K5, or K6 outage	1. *Risk duration of less than one hour:* a. Execute Residential Direct Load Control program. b. Execute Commercial Direct Load Control program. c. Execute Rider I program (limited to 15 times/year and 8 hours/billing cycle). 2. *Risk duration of greater than one hour:* a. Ask H-POWER for additional energy if not at full output.
2	XOSR < 0 MW	90 MW ≤ OSR < 180 MW	Any reheat or Kalaeloa Plant (1 CT operation) outage	1. *Any risk duration:* a. Implement steps of General Condition 1 section. b. Consider informing major commercial customers of situation (no conservation requested). c. Consider informing Government Agencies as needed. d. Consider informing large customers with emergency generators. i. No emergency generator power requested. ii. Provide two-hour lead time minimum (ideally, by mid-day for the evening peak); refer to Customer Notification Plan. e. Consider asking for voluntary conservation from residential customers via the media. Provide a two-hour lead time minimum (ideally, by mid-day for the evening peak).
3	XOSR < 0 MW	60 MW ≤ OSR < 90 MW	Any unit outage	1. *Any risk duration:* a. Ask AES for additional energy. b. Abnormal operating conditions, dispatch CIP CT-1 accordingly. c. Inform major commercial customers. Ask for voluntary conservation. d. Inform appropriate Government Agencies as needed. e. Inform large customers with generators. Schedule large customers with generators to go on emergency generator power (refer to Customer Notification Plan). f. Ask for voluntary conservation from residential customers via the media. Provide two-hour lead time minimum (ideally, by mid-day for the evening peak). g. Partially activate the Incident Management Team (refer to IMT Activation Plan).
4	XOSR < 0 MW	0 MW ≤ OSR < 60 MW	Manual load shed	1. *Any risk duration* a. Implement all items in General Condition 3. b. Ask all customers for conservation and to run their emergency generators. c. Plan and execute rolling blackouts. Provide minimum one-hour notice with plan details when possible (earlier if possible). d. If frequency is dropping below 59.0 Hz, consider manually shedding load. e. Activate IMT (refer to IMT Activation Plan).

Table 18. Generation Contingency Plans (Revision 17c)

Changes Made to the Contingency Plans Following the Outage

SysOps made the following changes to revision 16, resulting in contingency plans being updated in Revision 17c:

- For generation condition ALPHA: clarified the contingency plan.
- For generation condition BETA: clarified the contingency plan.
- For generation condition 1: lowered the threshold for implementing the contingency plan from a risk duration of two hours to a risk duration of one hour; included executing three demand response programs and requesting additional energy from H-POWER; removed the requirement of requesting additional energy from Kalaeloa and AES, as well as notifying major commercial customers and appropriate government agencies.
- For generation condition 2: lowered the threshold for implementing the contingency plan from a risk duration of two hours to any risk duration; added all of generation condition 1's actions and asking large customers to use their generators; removed the requirement of asking Kalaeloa, AES, and H-POWER for additional energy.
- For generation condition 3: lowered the threshold for implementing the contingency plan from a risk duration of two hours to any risk duration; added dispatching CIP CT-1, informing major commercial customers, requesting large customers to use their generators; asking for voluntary conservation, and partially activating the Incident Management Team; removed several requirements, including asking Kalaeloa and H-POWER for additional energy and executing three demand response programs.
- For generation condition 4: added asking all customers to conserve energy and activating the Incident Management Team; no requirements were removed.

B. DAILY GENERATION REPORTS

The Daily Generation Reports (DGR) are composed of nine sections:

1. **Today's Daily Capability.** Lists the capability and availability of all generation resources on O'ahu for the day of the report, plus the Generation Condition of the entire grid.
2. **Equipment Outage and Derating.** Lists the units that have planned or tripped outages and have been derated for the day of the report (excluding any risk conditions).
3. **Abnormal Conditions.** Lists the units with abnormal conditions for the day of the report (including redundant risk conditions).
4. **Yesterday's Operation.** Compares the MW and MW h data from the previous day against historical figures from one year ago.
5. **Historical Data.** Details the historical high day and evening peaks with current situations.
6. **Scheduled Unit Equipment Outage and Derating.** Lists the generation units with scheduled outages and deratings for the day of the report, together with the start and end date.
7. **Scheduled Unit Equipment Testing.** Lists the generation units scheduled to be tested on the day of the report.
8. **Definitions.** Lists the Generation Conditions (described in detail on page xx), and the day and evening peak periods.
9. **Weather.** Describes the statewide weather forecast for O'ahu for the day of the report, plus the south shore (south of the Ko'olaus, including Honolulu, Waikiki, Hawai'i Kai, and Kapolei) and Olomana (north of the Ko'olaus, including Kailua, Kaneohe, and Waimanalo) for the day of the report and the next three days.

The following pages show the Morning Editions of the Daily Generation Reports from January 12 and January 13, 2015. These reports have been formatted side by side on facing pages, so that the nine sections of conditions for the two days can be easily compared.

12 January 2015 Daily Generation Report: Section 1

1. TODAY'S SYSTEM CAPABILITY:

		Normal Capability	Derate	Available Capability	Running for Day Peak	Running for Eve Peak
	K1	86	-11	75	75	75
	K2	86		86	86	86
	K3	90		90	90	90
	K4	89	-89	0	0	0
	K5	142	-142	0	0	0
	K6	142	-142	0	0	0
	W7	87		87	87	87
	W8	90		90	90	90
	W3	49		49	49	49
	W4	49		49	49	49
	W5	57		57	57	57
	W6	56	-21	35	35	35
(deactivated 02/01/14)	H8	0		0		
(deactivated 02/01/14)	H9	0		0		
(changed 06/12/14)	W9	47		47	47	47
(changed 06/12/14)	W10	44		44	44	44
(changed 11/01/10)	CIP1	113		113		113
(changed 04/28/10)	DG	0		0		
	HECO Total	1227	-405	822	709	822
(changed 07/11/13)	HR	68.5	-33.5	35	35	35
(changed 9/28/05)	KL1	104	-14	90	90	90
(changed 9/28/05)	KL2	104	-104	0	0	0
	AES	180		180	180	180
	IPP Total	456.5	-151.5	305	305	305
	Total	1683.5	-556.5	1127	1014	1127
	Spinning Reserve for largest unit	-180		-180	-180	-180
	Capability	1503.5		947	834	947
				Peak Forecast	830	1030
				Excess Operating Spinning Reserve (XOSR)	4	-83
				Reserve Shutdown	113	0
				Generation Condition	ALPHA	TWO
				Total MW at risk	0	0
				Largest individual risk condition (in MW)	0	0
				Generation Condition upon loss of largest risk condition	ALPHA	TWO

Note that the above reheat capabilities are the normal pressure ratings and the above Waiau combustion turbine capabilities are the base ratings.

Figure 21. 12 January 2015, Daily Generation Report: Section 1

13 January 2015, Daily Generation Report: Section 1

1. TODAY'S SYSTEM CAPABILITY:

		Normal Capability	Derate	Available Capability	Running for Day Peak	Running for Eve Peak
	K1	86	-11	75	75	75
	K2	86		86	86	86
	K3	90		90	90	90
	K4	89	-89	0	0	0
	K5	142	-142	0	0	0
	K6	142	-142	0	0	0
	W7	87		87	87	87
	W8	90		90	90	90
	W3	49		49	49	49
	W4	49		49	49	49
	W5	57		57	57	57
	W6	56	-21	35	35	35
(deactivated 02/01/14)	H8	0		0		
(deactivated 02/01/14)	H9	0		0		
(changed 06/12/14)	W9	47		47		47
(changed 06/12/14)	W10	44		44	44	44
(changed 11/01/10)	CIP1	113		113	113	113
(changed 04/28/10)	DG	0		0		
	HECO Total	1227	-405	822	775	822
(changed 07/11/13)	HR	68.5	-13.5	55	55	55
(changed 9/28/05)	KL1	104	-14	90	90	90
(changed 9/28/05)	KL2	104	-104	0	0	0
	AES	180	-98	82	82	82
	IPP Total	456.5	-229.5	227	227	227
	Total	1683.5	-634.5	1049	1002	1049
	Spinning Reserve for largest unit	-180		-113	-113	-113
	Capability	1503.5		936	889	936
	Peak Forecast				810	1030
	Excess Operating Spinning Reserve (XOSR)				79	-94
	Reserve Shutdown				47	0
	Generation Condition				ALPHA	THREE
	Total MW at risk				0	0
	Largest individual risk condition (in MW)				0	0
	Generation Condition upon loss of largest risk condition				ALPHA	THREE

Note that the above reheat capabilities are the normal pressure ratings and the above Waiau combustion turbine capabilities are the base ratings.

Figure 22. 13 January 2015, Daily Generation Report: Section 1

12 January 2015, Daily Generation Report: Sections 2 & 3

2. EQUIPMENT OUTAGE AND DERATING (excluding risk conditions)

	Units	Remarks (sorted by From time)	From	To
*	K5	Unavailable, tripped offline; turbine issues.	01/12/15 0537	
X	K5	Blocked at 82 MW; high furnace pressure.	01/11/15 1625	01/12/15 0537
*	K1	Blocked at 75 MW; fuel oil supply control instabilities.	01/10/15 1822	
X	K5	Blocked at 86 MW; high furnace pressure.	01/09/15 0632	01/11/15 1625
	W6	Blocked at 35 MW; boiler hot spot on 4th floor.	01/08/15 0756	
	HR	Blocked at 35 MW; Boiler #1 & #3 online.	1/8/15 0049	
	K4	Unavailable, maintenance outage.	12/18/14 2238	ETR 01/18/15
	KL2	Tripped offline; turbine vibrations.	12/09/14 1745	ETR 01/18/15
	K6	Unavailable; planned maintenance.	10/10/14 2242	ETR 02/2015

S = Scheduled short term from now to next report
* = Additions or changes to previous items
X = Completions

3. ABNORMAL CONDITIONS (including redundant risk conditions)

	Units	Remarks (sorted by From time)	From	To	MW At Risk
X	K3	100% risk; no SSWP backup.	01/09/15 1220	01/10/15 1123	90
				Total MW at Risk	0
				Largest Individual Risk Condition (in MW)	0

S = Scheduled short term from now to next report
* = Additions or changes to previous items
X = Completions
(MW at Risk in red are not counted in total)

Figure 23. 12 January 2015, Daily Generation Report: Sections 2 & 3

13 January 2015, Daily Generation Report: Sections 2 & 3

2. EQUIPMENT OUTAGE AND DERATING (excluding risk conditions)

	Units	Remarks (sorted by From time)	From	To
X	W9	Unavailable, tripped offline; low frequency problems.	01/12/15 1403	1443
*	AES	Good for 82 MW; Boiler A back online.	01/13/15 0636	
X	AES	Tripped offline; Boiler B tube leak.	01/12/15 1352	01/13/15 0211
*	HR	Blocked at 55 MW; all 3 boilers online.	01/12/15 1100	
	K5	Unavailable, tripped offline; turbine issues.	01/12/15 0537	
	K1	Blocked at 75 MW; fuel oil supply control instabilities.	01/10/15 1822	
	W6	Blocked at 35 MW; boiler hot spot on 4th floor.	01/08/15 0756	
X	HR	Blocked at 35 MW; Boiler #1 & #3 online.	01/8/15 0049	01/12/15 1100
	K4	Unavailable, maintenance outage.	12/18/14 2238	ETR 01/18/15
	KL2	Tripped offline; turbine vibrations.	12/09/14 1745	ETR 01/23/15
	K6	Unavailable; planned maintenance.	10/10/14 2242	ETR 02/2015

S = Scheduled short term from now to next report
* = Additions or changes to previous items
X = Completions

3. ABNORMAL CONDITIONS (including redundant risk conditions)

	Units	Remarks (sorted by From time)	From	To	MW At Risk
				Total MW at Risk	0
				Largest Individual Risk Condition (in MW)	0

S = Scheduled short term from now to next report
* = Additions or changes to previous items
X = Completions
(MW at Risk in red are not counted in total)

Figure 24. 13 January 2015, Daily Generation Report: Sections 2 & 3

12 January 2015, Daily Generation Report: Sections 4 & 5

4. YESTERDAY'S OPERATION

Friday 1/9/15	THIS YEAR ACT	LAST YEAR ACT	CHANGE
DAY PEAK MW:	818	896	-9%
EVE PEAK MW:	984	1015	-3%
DAILY MIN MW:	552	574	-4%
Jan Pk Forecast (per Aug 2014 update)	1183	(w/ Tesoro gen online)	
KALAELOA MWH:	2,011	3,756	-46%
HRRV MWH:	929	1,035	-10%
AES MWH:	4,263	4,142	3%
IPP NET MWH:	7,203	8,933	-19%
AS AVAILABLE:	107	282	-62%
HECO NET MWH:	10,450	9,576	9%
SYS NET MWH:	17,760	18,791	-5%
% IPP NET MWH:	41%	48%	
% AS AVAILABLE :	1%	2%	

5. HISTORICAL DATA

	Day Peak		Evening Peak	
HECO Record Peak	1315 MW	8/28/06	1327 MW	10/12/04
Previous Record	1291 MW	8/17/04	1319 MW	10/11/04
2014 Peak	1107 MW	10/07/14	1201 MW	09/22/14
2015 YTD Peak	838 MW	01/02/15	995 MW	01/05/15
Previous 2015 Peak	718 MW	01/01/15	993 MW	01/02/15

Figure 25. 12 January 2015, Daily Generation Report: Sections 4 & 5

13 January 2015, Daily Generation Report: Sections 4 & 5

4. YESTERDAY'S OPERATION

Monday 1/12/15

	THIS YEAR ACT	LAST YEAR ACT	CHANGE
DAY PEAK MW:	835	946	-12%
EVE PEAK MW:	921	1093	-16%
DAILY MIN MW:	559	590	-5%
Jan Pk Forecast (per Aug 2014 update)	1183	(w/ Tesoro gen online)	
KALAELOA MWH:	2,147	2,085	3%
HRRV MWH:	1,180	1,342	-12%
AES MWH:	2,595	4,284	-39%
IPP NET MWH:	5,922	7,711	-23%
AS AVAILABLE:	113	106	7%
HECO NET MWH:	11,368	11,918	-5%
SYS NET MWH:	17,403	19,735	-12%
% IPP NET MWH:	34%	39%	
% AS AVAILABLE :	1%	1%	

5. HISTORICAL DATA

	Day Peak		Evening Peak	
HECO Record Peak	1315 MW	8/28/06	1327 MW	10/12/04
Previous Record	1291 MW	8/17/04	1319 MW	10/11/04
2014 Peak	1107 MW	10/07/14	1201 MW	09/22/14
2015 YTD Peak	838 MW	01/02/15	995 MW	01/05/15
Previous 2015 Peak	718 MW	01/01/15	993 MW	01/02/15

Figure 26. 13 January 2015, Daily Generation Report: Sections 4 & 5

12 January 2015, Daily Generation Report: Section 6

6. SCHEDULED UNIT EQUIPMENT OUTAGE AND DERATING

	Units	Remarks (sorted by From time)	From	To
	K6	Planned outage (Boiler, Stack, FWH, Turbine, GCRTU replace)	10/10/14	
	WPP	Black start generator unavailable for annual maintenance	01/14/15	1 day
S	K2	Block at 60 MW, 100% risk; travel screen install.	01/14/15	1 day
	W4	Maintenance outage (boiler leak, cc, turbine gov valve, etc.)	01/19/15	01/29/15
	K5	Maintenance outage (APH wash only)	01/19/15	01/24/15
	W9	Maintenance outage (MCE testing, FI)	01/26/15	01/30/15
	W3	Maintenance outage (turbine rails, cc)	02/01/15	02/06/15
	W7	Maintenance outage (APH wash, CW tunning clean)	02/08/15	02/20/15
	W9	Planned outage (Generator, dc battery replacement)	02/15/15	04/24/15
	K3	Maintenance outage (Blr/APH wash, etc.)	02/22/15	03/20/15
	W6	Maintenance outage (APH wash, boiler hot spot, CW tunnel cln)	02/22/15	03/16/15
	W3	Maintenance outage (Blr inspect, gen inspect, etc.)	02/22/15	03/13/15
	W5	Maintenance outage (APH wash, CW tunnel clean)	03/29/15	04/10/15
	AES	Annual maintenance outage	04/16/15	05/10/15
	W10	Planned outage (Generator, dc battery bank, etc.)	05/03/15	07/10/15

S = Scheduled short term – not on Power Supply O&M Planned Maintenance Schedule
* = Additions or changes to previous items

Figure 27. 12 January 2015, Daily Generation Report: Section 6

13 January 2015, Daily Generation Report: Section 6

6. SCHEDULED UNIT EQUIPMENT OUTAGE AND DERATING

	Units	Remarks (sorted by From time)	From	To
	K6	Planned outage (Boiler, Stack, FWH, Turbine, GCRTU replace)	10/10/14	
	WPP	Black start generator unavailable for annual maintenance	~~01/14/15~~	~~1 day~~
S	K2	Block at 60 MW, 100% risk; travel screen install.	~~01/14/15~~	~~1 day~~
	W4	Maintenance outage (boiler leak, cc, turbine gov valve, etc.)	01/19/15	01/29/15
	K5	Maintenance outage (APH wash only)	01/19/15	01/24/15
	W9	Maintenance outage (MCE testing, FI)	01/26/15	01/30/15
	W3	Maintenance outage (turbine rails, cc)	02/01/15	02/06/15
	W7	Maintenance outage (APH wash, CW tunning clean)	02/08/15	02/20/15
	W9	Planned outage (Generator, dc battery replacement)	02/15/15	04/24/15
	K3	Maintenance outage (Blr/APH wash, etc.)	02/22/15	03/20/15
	W6	Maintenance outage (APH wash, boiler hot spot, CW tunnel cln)	02/22/15	03/16/15
	W3	Maintenance outage (Blr inspect, gen inspect, etc.)	02/22/15	03/13/15
	W5	Maintenance outage (APH wash, CW tunnel clean)	03/29/15	04/10/15
	AES	Annual maintenance outage	04/16/15	05/10/15
	W10	Planned outage (Generator, dc battery bank, etc.)	05/03/15	07/10/15

S = Scheduled short term – not on Power Supply O&M Planned Maintenance Schedule
* = Additions or changes to previous items

Figure 28. 13 January 2015, Daily Generation Report: Section 6

12 January 2015, Daily Generation Report: Sections 7 & 8

7. SCHEDULED UNIT EQUIPMENT TESTING

	Units	Remarks (sorted by From time)	From	To
	W9/10	30-min callback (separately); MCE motor testing.	01/13/15	1 day

S = Scheduled short term from now to next report
* = Additions or changes to previous items

8. DEFINITIONS

Generation Condition

ALPHA	XOSR>0 MW, at least 1 unit in reserve
BETA	XOSR>0 MW, no available units
ONE	-40 MW <= XOSR < 0 MW
TWO	-90 MW <= XOSR < -40 MW
THREE	-180 MW <= XOSR < -90 MW
FOUR	XOSR <-180 MW

Day and Evening Peak

There are three periods to determine the day and evening peaks:

Day Peak	0001 to 1500
Deadband	1501 to 1700
Evening Peak	1701 to 2400

The day peak normally occurs between 0001 and 1500
The evening peak always occurs between 1701 and 2400
If the highest peak of the day occurs in the deadband, this will be considered the day peak

Figure 29. 12 January 2015, Daily Generation Report: Sections 7 & 8

13 January 2015, Daily Generation Report: Sections 7 & 8

7. SCHEDULED UNIT EQUIPMENT TESTING

	Units	Remarks (sorted by From time)	From	To
	W9/10	30-min callback (separately); MCE motor testing.	~~01/13/15~~	~~1 day~~

S = Scheduled short term from now to next report
* = Additions or changes to previous items

8. DEFINITIONS

Generation Condition

ALPHA	XOSR>0 MW, at least 1 unit in reserve
BETA	XOSR>0 MW, no available units
ONE	-40 MW <= XOSR < 0 MW
TWO	-90 MW <= XOSR < -40 MW
THREE	-180 MW <= XOSR < -90 MW
FOUR	XOSR <-180 MW

Day and Evening Peak

There are three periods to determine the day and evening peaks:

Day Peak	0001 to 1500
Deadband	1501 to 1700
Evening Peak	1701 to 2400

The day peak normally occurs between 0001 and 1500
The evening peak always occurs between 1701 and 2400
If the highest peak of the day occurs in the deadband, this will be considered the day peak

Figure 30. 13 January 2015, Daily Generation Report: Sections 7 & 8

12 January 2015, Daily Generation Report: Section 9

9. WEATHER: (including Oahu South Shore and Olomana forecasts)

SYNOPSIS (statewide)

The relatively dry, light wind pattern will continue through much of the week as a ridge remains over the islands. Winds will be light enough for local land and sea breezes through much of the week. A front passing north of the state tonight, and another Thursday night may bring southwesterly winds to the islands for brief periods.

OAHU SOUTH SHORE- including: Honolulu, Waikiki, Hawaii Kai, Kapolei	**OLOMANA- including: Kailua, Kaneohe, Waimanalo**
Today Sunny. Isolated light showers in the afternoon. Highs around 79. West winds around 10 mph shifting to the southwest in the late morning and afternoon. Chance of rain 20 percent.	**Today** Sunny. Highs 75 to 80. Southwest winds around 10 mph.
Tonight Mostly clear. Lows 54 to 62. Light winds.	**Tonight** Mostly clear. Lows around 60. Light winds.
Tuesday Sunny and haze. Highs around 79. Light winds.	**Tuesday** Mostly sunny. Haze. Highs 76 to 81. Light winds.
Tuesday Night Mostly clear. Haze. Lows 58 to 65. Light winds.	**Tuesday Night** Mostly clear. Haze. Lows around 65. West winds around 10 mph.
Wednesday Sunny and haze. Highs 78 to 83. Light winds.	**Wednesday** Sunny and haze. Highs 78 to 83. West winds around 10 mph shifting to the east in the late morning and afternoon.
Wednesday Night Mostly clear. Haze. Lows 58 to 66. South winds around 10 mph.	**Wednesday Night** Mostly clear. Haze. Lows around 66. South winds around 10 mph.
Thursday Sunny and haze. Highs around 80. South winds around 10 mph.	**Thursday** Sunny and haze. Highs 76 to 81. South winds around 10 mph.

Figure 31. 12 January 2015, Daily Generation Report: Section 9

13 January 2015, Daily Generation Report: Section 9

9. WEATHER: (including Oahu South Shore and Olomana forecasts)

SYNOPSIS (statewide)

Light winds and mostly dry conditions with local land and sea breezes will prevail through Thursday. A weak front will increase clouds and rain slightly around Kauai by Friday or Saturday, but should have little effect elsewhere.

OAHU SOUTH SHORE- including: Honolulu, Waikiki, Hawaii Kai, Kapolei	**OLOMANA- including: Kailua, Kaneohe, Waimanalo**
Today Sunny and haze. Highs around 79. Light winds becoming south around 10 mph in the late morning and afternoon.	**Today** Sunny and haze. Highs around 78. Light winds becoming south around 10 mph in the late morning and afternoon.
Tonight Mostly clear. Haze. Lows 59 to 66. Light winds.	**Tonight** Mostly clear. Haze. Lows around 65. Southwest winds around 10 mph early in the evening becoming light.
Wednesday Sunny and haze. Highs 78 to 83. Southwest winds up to 10 mph.	**Wednesday** Sunny and haze. Highs around 80. Light winds becoming southeast around 10 mph in the late morning and afternoon.
Wednesday Night Mostly clear with isolated light showers. Haze. Lows 60 to 68. South winds around 10 mph. Chance of rain 20 percent.	**Wednesday Night** Mostly clear. Haze. Lows around 67. South winds around 10 mph.
Thursday Sunny. Isolated light showers in the morning. Haze through the day. Highs around 81. South winds around 10 mph. Chance of rain 20 percent.	**Thursday** Sunny and haze. Highs around 79. South winds around 10 mph.
Thursday Night Mostly clear with isolated showers. Lows 60 to 68. Light winds. Chance of rain 20 percent.	**Thursday Night** Mostly clear. Lows around 67. Light winds.
Friday Sunny. Isolated showers in the morning. Highs 78 to 83. Light winds. Chance of rain 20 percent.	**Friday** Sunny. Highs around 81. Light winds.

Figure 32. 13 January 2015, Daily Generation Report: Section 9

C. OUTAGE NOTIFICATION LIST

The following Hawaiian Electric personnel are notified in the event of any outage. The rationale: each person is a company executive; a manager or director concerned with power, generation, or energy resources; or personnel communicating with public audiences including our customers.

Alan Oshima	President and Chief Executive Officer
Tayne Sekimura	Senior Vice President, Chief Financial Officer
Stephen McMenamin	Senior Vice President, Chief Information Officer
Patricia Wong	Senior Vice President, Corporate Services
Jim Alberts	Senior Vice President, Customer Service
Susan Li	Senior Vice President, General Counsel
Lynne Unemori	Vice President, Corporate Relations
Darcy Endo-Omoto	Vice President, Government and Community Affairs
Joe Viola	Vice President, Regulatory Affairs
Richard Houck	Vice President, Enterprise Project Management
Colton Ching	Vice President, Energy Delivery
Shelee Kimura	Vice President, Corporate Planning and Business Development
Ron Cox	Vice President, Power Supply
Scott Seu	Vice President, Energy Resources and System Operations
Patsy Nanbu	Vice President. Regulatory Affairs
Enrique Che	Manager, Customer Service
Natalie Epenesa	Manager, Customer Relations
Cynthia Sugiyama	Corporate Communication Leader
Earlynne Maile	Manager, Asset Management
Shawn Tasaka	
Kerstan Wong	
Robert Tsuchiya	Manager, Test and Substations
Rodney Chong	Manager, Renewable Acquisition
Brenner Munger	Manager, Environmental Department
Cecily Barnes	
Tony Taparra	Manager, Generation Operations
Martin McDonough	
Michael Yuen	Manager, Power Supply Engineering
Robert Young	Manager, System Operations
Ross Sakuda	Manager, System Planning
Ken Fong	Manager, Transmission & Distribution Planning
Colette Miller	Director, Energy Contract Management

Bill Carreira	
Patti-Jo Day	Director Customer Account Services
Dan Sakamoto	Director, Key Account Management
Barbara Heckathorn	Director, Corporate Communication
Darren Pai	
Sharon Higa	Senior Communication Consultant
Teri Theuriet	Senior Communication Consultant
Donna Mun	Director, Online Communication
Gina Kealoha	Supervisor, Customer Assistance Center
Doug White	Supervisor, Customer Assistance Center
Peter Okunami	Senior Engineer, System Operation
Kevin Saito	Operating Superintendent, System Operation
IPP (zz$SysOp-IPP)	Independent Power Producer hot line
System Operation Administrator	

D. RESERVE MARGIN CALCULATIONS

Hawaiian Electric's AOS reports include calculations for projected system reserve margins. The calculations are based on projected system peak demand load and the total net generation capacity.

2014 Reserve Margin Calculations

Table 19 shows the data used to calculate the 2014 reserve margins.

Year	Total Net Generation Capacity	System Peak Demand Load	Interruptible Load	Reserve Margin
2013	1,778 MW	1,153 MW	47 MW	61%
2014	1,679 MW	1,173 MW	44 MW	49%
2015	1,679 MW	1,195 MW	50 MW	47%
2016	1,679 MW	1,203 MW	57 MW	47%
2017	1,586 MW	1,223 MW	65 MW	37%
2018	1,586 MW	1,228 MW	71 MW	37%

Table 19. 2014 Reserve Margins

Total net generation capacity is the sum of utility-owned firm generation (1,214.3 MW),

2015 Reserve Margin Calculations (without Variable Generation)

Table 20 shows the data used to calculate the 2015 reserve margins without variable generation.

Year	Total Net Generation Capacity	System Peak Demand Load	Interruptible Load	Reserve Margin
2014	1,671 MW	1,170 MW	26 MW	46%
2015	1,679 MW	1,195 MW	29 MW	44%
2016	1,679 MW	1,203 MW	36 MW	44%
2017	1,586 MW	1,223 MW	39 MW	34%
2018	1,586 MW	1,228 MW	42 MW	34%
2019	1,586 MW	1,238 MW	45 MW	33%

Table 20. 2015 Reserve Margins(without Variable Generation)

2015 Reserve Margin Calculations (with Variable Generation)

Table 21 shows the data used to calculate the 2015 reserve margins with variable generation.

Year	Total Net Generation Capacity	System Peak Demand Load	Interruptible Load	Variable Generation	Reserve Margin w/ Variable Generation
2014	1,671 MW	1,170 MW	26 MW	10 MW	47%
2015	1,679 MW	1,195 MW	29 MW	10 MW	45%
2016	1,679 MW	1,203 MW	36 MW	10 MW	45%
2017	1,586 MW	1,223 MW	39 MW	10 MW	35%
2018	1,586 MW	1,228 MW	42 MW	10 MW	35%
2019	1,586 MW	1,238 MW	45 MW	10 MW	34%

Table 21. 2015 Reserve Margins (with Variable Generation)

Reserve Margin Data

Various factors affect the data used to calculate the annual reserve margins.

Total Net Generation Capacity

Total net generation capacity, determined at the time of the annual system peak demand load, is the sum of the AOS rating in MW for all utility-owned and IPP firm generation.

Units	2013 RM	2014 RM	2015–16 RM	2017+ RM
Utility-owned units	1,321.6	1,214.3	1,214.3	1,121.7
AES Hawai'i	180.0	180.0	180.0	180.0
H-POWER	68.5	68.5	68.5	68.5
Kalaeloa CTs	208.0	208.0	208.0	208.0
Airport DSG	0.0	0.0	8.0	8.0
Total	1,778.1	1,670.8	1,678.8	1,586.2

Table 22. Total Net Generation Capacity AOS Ratings

The 2013 utility-owned central station units include the Honolulu generating station; the 2014 utility-owned units exclude the deactivated Honolulu units; the 2017+ utility-owned units exclude the planned deactivation of Waiau 3 and Waiau 4.

The 2015 calculations include the expected addition of Airport Dispatchable Standby Generation (DSG). Kalaeloa is assumed to continue in service after 2016. AES Hawai'i is assumed to continue in service after 2022.

See Table 1 (page 12) for a detailed breakdown of the AOS rating for each utility-owned central station unit.

System Peak Demand Load

The system peak demand loads are based on Hawaiian Electric's February 2014 Sales and Peak Forecast, and includes the estimated peak reduction benefits of third-party energy efficiency DSM programs. The annual forecasted system peak is expected to occur in the month of October.

The peak for 2013–2014 includes approximately 25 MW of standby load, and approximately 27 MW of standby load for the remaining data. The standby load is calculated from the load offset provided by on-site co-generation output at the two oil refineries at the time of the recorded system peak. It varies from year to year.

The System Peak Demand Load changed from a projected 2014 amount of 1,173 MW to an actual amount of 1,170 MW in 2015.

Interruptible Load

Interruptible Load impacts are net-to system, and are approximate impacts at the system peak.

Variable Generation

The variable generation is an amount that we estimate will always be available on the power grid.

E: UNIT EFOR(D) EXPLANATIONS

We carefully review the EFORd numbers of our generating units for previous years, then recommend EFORd numbers for the upcoming year. Here are explanations of how we arrived at our recommendations.

Waiau 3 and Waiau 4

In the 2014 AOS, the EFORd for Waiau 3 was 6.7%. The actual EFORd for 2014 for Waiau 3 was 33.2 %. In the 2014 AOS, the EFORd for Unit 4 was 3.8%. The actual EFORd for 2014 for Waiau 4 was 5.0%.

Hawaiian Electric believes that Waiau 3 and Waiau 4 will continue to be operated and maintained in a similar manner. Although Waiau 3 and Waiau 4 are similar units, their maintenance plan includes future deactivation. Therefore the maintenance strategies on these units are different compared to other units and the units are at different stages of material condition. Yet, Waiau 3 and Waiau 4 will be operated and dispatched in similar manner compared to recent history. Hawaiian Electric therefore does not believe that averaging the EFORd for Waiau 3 and Waiau 4 together will provide accurate assumption of each unit's future performance. Instead, we elect to base the Waiau 3 and Waiau 4 EFORd numbers on individual unit averages over the previous five years. Hawaiian Electric believes this will give a reasonable assumption of unit performance to be used as the 2015 AOS EFORd. Thus, for Waiau 3, an EFORd of 13.2% was recommended and for Waiau 4, an EFORd of 3.8% was recommended for the 2015 AOS EFORd.

Waiau 5 and Waiau 6

In the 2014 AOS, the EFORd rate for Waiau 5 and Waiau 6 was 2.0% based on the average actual EFORd numbers rates for both units for the recent 5 years. The actual EFORd for 2014 for Waiau 5 and Waiau 6 were 3.5% and 7.2%, respectively. For the 2015 AOS analysis, we decided to continue to use the average of the actual EFORd rates for the past 5 years. This approach recognizes that Waiau 5 and Waiau 6 are similar units under the same maintenance strategy yet at different stages of maintenance. In addition, Waiau 5 and Waiau 6 will be dispatched and operated similar in coming years. Averaging historic performance gives an accurate estimation of each unit's performance. The combined average of Waiau 5 and Waiau 6 five year historic EFORd is 2.7% and was recommended for the 2015 AOS EFORd for both Waiau 5 and Waiau 6.

Waiau 7 and Waiau 8; Kahe 3 and Kahe 4

These four units are of similar size, design, and vintage, and are dispatched as baseload units with similar duty cycles. They also have a similar maintenance strategy. With each unit at various stages of the maintenance plans, it was recommended that averaging all four units provides the best indication of EFORd to be used for the 2015 AOS analysis. Accordingly, in the 2014 AOS, the EFORd rate of 3.7% was used for these four units. The actual EFORd for 2014 for Waiau 7, Waiau 8, Kahe 3, and Kahe 4 were 0.0%, 6.7%, 2.2%, 9.0%, respectively, with an average of 4.5%. For the 2015 AOS analysis, we decided to continue to use the average of the actual EFORd rates for the four units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2015 as they were in recent years. As a result, an EFORd of 3.8% was recommended for the 2015 AOS EFORd for all four units.

Waiau 9 and Waiau 10

In the 2014 AOS, the EFORd rate for Waiau 9 and Waiau 10 was 7.2% based on the average of the actual EFORd numbers for both units for the recent 5 years. The actual EFORd in 2014 for Waiau 9 and Waiau 10 were 0.9% and 3.4%, respectively, and averaged to be 2.1% for the two units. For the 2015 AOS analysis, we decided to continue to use the average of the actual EFORd rates for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2015 as they were in recent years and that each unit has similar maintenance strategies. As a result, an EFORd of 7.2% was recommended for the 2015 AOS EFORd for both units.

Kahe 1 and Kahe 2

In the 2014 AOS, the EFORd for Kahe 1 and Kahe 2 was 3.6% based on the average of the actual EFORd numbers for both units for the recent 5 years. The actual EFORd in 2014 for Kahe 1 and Kahe 2 were 2.8% and 10.6%, respectively, and averaged to be 6.7% for both units. For the 2015 AOS analysis, we decided to continue to use the average of the actual EFORd for both units for the past 5 years. This approach also recognizes that these units will be dispatched and operated similarly in 2015 as they were in recent years. In addition, these similar units have similar maintenance strategies yet are at different stages of their maintenance strategy. Averaging the two units performance allows for the normalization of performance. As a result, an EFORd of 4.0% was recommended for the 2015 AOS EFORd both units.

Kahe 5 and Kahe 6

In the 2014 AOS, the EFORd for Kahe 5 and Kahe 6 was 4.7% based on the average of the actual EFORd numbers for the recent 5 years. The actual EFORd for 2014 for Kahe 5 and Kahe 6 were 6.1% and 1.8% respectively, and averaged to be 3.9% for both units. Kahe 5 and Kahe 6 are similar units and are operated and maintained in similar manner. For the 2015 AOS analysis, we decided to continue to average the two units performance over the last five years. As with other similar units, this normalizes the stage of each unit's maintenance strategy. As a result, an EFORd of 4.3% was recommended for the 2015 AOS EFORd for both units.

CIP CT-1

On August 3, 2009, CIP CT-1 was placed in service (that is, tied into the electrical grid and producing power). In the 2014 AOS, the EFORd for CIP CT-1 was 8.2% based on the average of CIP CT-1 actual EFORd for the recent 5 years. The actual EFORd for 2014 for CIP CT-1 was 9.0%. For the 2015 AOS analysis, we decided to continue to use the average of the actual EFORd rate for the past 5 years. This approach recognizes that this unit will be dispatched and operated similarly in 2015 as it was in recent years. As a result, an EFORd of 6.4% was recommended for the 2015 AOS EFORd for CIP CT-1.

F. LOSS OF LOAD PROBABILITY (LOLP) EXPLANATION

> Use these documents:
>
> HECO 2003 AOS Response to CA-IR-1.pdf
> LOLP-white.ppt
>
> To discuss the historical aspects of how they decided on 4.5 years for a LOLP.

G. GENERATOR INERTIA CONSTANT H VALUES

Each generation unit has an inertia Constant H value. System planners use the inertia Constant H to calculate the stability of the power grid because Constant H values do not vary widely with the unit (machine) rating and the unit's speed.

Constant H is defined as the ratio of kinetic energy at the unit's rated speed to the rated apparent power of the unit. As an equation:

$$H = \frac{\text{Stored energy (MJ)}}{\text{Machine rating (MVA)}}$$

Thus, Constant H is expressed as MJ/MVA. MVA stands for Mega Volt Amp or Volts x Amp /1,000,000. For example, a total load requirement of 1,000 volts and 5,000 amps (1,000 x 5,000 = 5,000,000 VA) can be expressed as 5 MVA. This is called "apparent power'" because it considers both the resistive load and the reactive load. If the resistive load (watts) is 4,000,000 watts (4 megawatts) and the reactive load is 3,000,000 VARs (3 megavars), the apparent power is 5,000,000 VA (or 5 MVA).

Table 23 lists the constant H value for each generation unit on the Hawaiian Electric grid (except wind) and the corresponding calculated 100 MVA base value. (PSSE—Power System Simulator for Engineering—are software programs used for electrical transmission networks.)

Unit	Generator MVA	PSSE Constant H	PSSE Constant H (100 MVA Base)
Kahe 1	96.00	4.44	4.26
Kahe 2	96.00	4.44	4.26
Kahe 3	101.00	3.54	3.57
Kahe 4	101.00	3.54	3.57
Kahe 5	158.80	4.36	6.92
Kahe 6	158.80	4.36	6.92
Waiau 3	96.00	4.44	4.26
Waiau 4	96.00	4.44	4.26
Waiau 5	57.50	4.51	2.59
Waiau 6	57.50	4.51	2.59
Waiau 7	64.00	4.07	2.61
Waiau 8	64.00	4.00	2.56
Waiau 9 (CT)	62.50	4.04	2.53
Waiau 10 (CT)	64.00	3.95	2.53
Honolulu 8	57.00	7.84	4.47
Honolulu 9	57.00	7.84	4.47
CIP CT-1	162.00	4.72	7.65
AES Hawai‘i	239.00	2.57	6.14
H-POWER (HRRV)	75.00	2.78	2.09
H-POWER (HRRV) Expansion	42.13	3.41	1.44
Kalaeloa (KPLP) CT-1	119.20	4.96	5.91
Kalaeloa (KPLP) CT-2	119.20	4.96	5.91
Kapolei Sustainable Energy Park (Tesoro)	29.45	1.80	0.53
Kalaeloa Solar Two (KS2)	61.06	4.70	2.87

Table 23. Generating Unit Inertia Constants

H. NEWS RELEASES

As soon as practicable following the AES trip event at 1:52 PM on January 12, 2015, Corporate Communication began writing and issues news releases to the media. In total, Corporate Communication issued six releases from the beginning of the trip event until two days later.

The issue date and times (when applicable), plus their titles are:

- January 12, 2015; 3:35 PM: Loss of Power Generators causes O'ahu outages.
- January 12, 2015; 4:35 PM: Rotating outages to be initiated on O'ahu.
- January 12, 2015; 7:30 PM: Rotating outages initiated on O'ahu.
- January 12, 2015; 8:30 PM: Power retried to O'ahu customers.
- January 13, 2015: O'ahu customers asked to conserve electricity.
- January 14, 2015: Call for energy conservation lifted.

The actual news releases appear on the following pages.

January 12, 2015; 3:35 PM: Loss of Power Generators Causes O'ahu Outages

Hawaiian Electric

NEWS RELEASE

CONTACT: (808) 223-9932 **FOR IMMEDIATE RELEASE**

Loss of power generators causes O'ahu outages

Customers are asked to conserve power
Rotating outages may be necessary

HONOLULU, Jan. 12, 2015 – The loss of several generating units, including the largest on the island operated by independent power producer AES, required Hawaiian Electric to briefly shut off power for about 10 minutes to about 22,000 customers at approximately 1:50 p.m. The targeted emergency outages were necessary to avoid a more widespread outage or damage to the electric system from an imbalance of too much demand versus too little available generation.

The outages affected customers in areas across the island, including Kailua, Kaneohe, Maunawili, Wailupe, Halawa, Makalapa, Waipahu, and Waimano. Power to most affected customers was restored shortly after 2 p.m.

The outage occurred after a 180-megawatt power plant operated by AES, an independent power producer, unexpectedly went out of service. In addition, the Kalaeloa Power Plant, also owned and operated by an independent power producer, has been providing less than half its maximum output of 208 megawatts as it goes through repairs for an equipment problem. One of Hawaiian Electric's generating units at the Kahe Power Plant, which normally produces 135 megawatts, is also off line after it unexpectedly experienced problems this morning.

Due to the loss of generation, Hawaiian Electric may need to initiate rolling outages starting at approximately 5 p.m. The outages would last approximately one hour and rotate through various parts of the island. This may be necessary to ensure the demand for power does not exceed the amount of available generation, which could result in an islandwide outage.

Hawaiian Electric is asking O'ahu customers to assist with the situation by conserving electricity use this evening, especially between 5 and 9 p.m. This precaution is intended to ensure sufficient power is available to meet the early evening peak demand for electricity. Suggested steps include turning off or lessening use of air conditioners, delaying hot showers and dishwashing activities, and minimizing cooking until later in the evening.

"We apologize for this disruption and thank our customers for their patience. We understand the evening hours, especially today with the football game, are an especially inconvenient time to cut back on electricity, but with everyone's help we hope to avoid an emergency situation," said Darren Pai, Hawaiian Electric spokesperson.

More…

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Figure 33. January 12, 2015; 3:35 PM News Release: Loss of Power Generators Causes O'ahu Outages (1–2)

Loss of power generators causes outages
Page 2 of 2
Jan. 12, 2015

Hawaiian Electric is also asking its larger commercial customers to voluntarily reduce electricity usage. System operators will also work on further reducing the demand for power by using Hawaiian Electric's demand response programs. These voluntary programs help lower the overall use of electricity by reducing the energy output of certain appliances or equipment, such as water heaters, for participating residential customers and non-essential lighting and heating or cooling systems for participating commercial customers.

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Figure 34. January 12, 2015; 3:35 PM News Release: Loss of Power Generators Causes O'ahu Outages (2–2)

January 12, 2015; 4:35 PM: Rotating Outages to be Initiated on O‘ahu

Hawaiian Electric

NEWS RELEASE

CONTACT: **(808) 223-9932** **FOR IMMEDIATE RELEASE**

Rotating outages to be initiated on O`ahu
Loss of power generators causes O`ahu outages
Customers are asked to conserve power

Update as of 4:45 p.m., Jan. 12, 2015 – Below is the planned rolling outage schedule (times are approximate). Hawaiian Electric system operators will evaluate demand for electricity and based on that, will determine the exact start time and whether all of the noted areas will be affected:

Begin	End	Area
5 p.m.	6 p.m.	Nuuanu-School Street area, all of Hawai`i Kai, sections of Waimanalo and Kahala
6 p.m.	7 p.m.	Most of Waipahu, sections of Pearl City, Kunia, Ewa Beach, Waiawa, Crestview, sections of Mililani
7 p.m.	8 p.m.	Pearl City, Waimalu, Waialua, Kuilima

HONOLULU, Jan. 12, 2015 – The loss of several generating units, including the largest on the island operated by independent power producer AES, required Hawaiian Electric to briefly shut off power for about 10 minutes to about 22,000 customers at approximately 1:50 p.m. The targeted emergency outages were necessary to avoid a more widespread outage or damage to the electric system from an imbalance of too much demand versus too little available generation.

The outages affected customers in areas across the island, including Kailua, Kaneohe, Maunawili, Wailupe, Halawa, Makalapa, Waipahu, and Waimano. Power to most affected customers was restored shortly after 2 p.m.

The outage occurred after a 180-megawatt power plant operated by AES, an independent power producer, unexpectedly went out of service. In addition, the Kalaeloa Power Plant, also owned and operated by an independent power producer, has been providing less than half its maximum output of 208 megawatts as it goes through repairs for an equipment problem. One of Hawaiian Electric's generating units at the Kahe Power Plant, which normally produces 135 megawatts, is also off line after it unexpectedly experienced problems this morning.

Due to the loss of generation, Hawaiian Electric may need to initiate rolling outages starting at approximately 5 p.m. The outages would last approximately one hour and rotate through various parts of the island. This may be necessary to ensure the demand for power does not exceed the amount of available generation, which could result in an islandwide outage.

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Figure 35. January 12, 2015; 4:35 PM News Release: Rotating Outages to be Initiated on O‘ahu (1–2)

Loss of power generators causes outages
Page 2 of 2
Jan. 12, 2015

More…

Hawaiian Electric is asking O`ahu customers to assist with the situation by conserving electricity use this evening, especially between 5 and 9 p.m. This precaution is intended to ensure sufficient power is available to meet the early evening peak demand for electricity. Suggested steps include turning off or lessening use of air conditioners, delaying hot showers and dishwashing activities, and minimizing cooking until later in the evening.

“We apologize for this disruption and thank our customers for their patience. We understand the evening hours, especially today with the football game, are an especially inconvenient time to cut back on electricity, but with everyone's help we hope to avoid an emergency situation,” said Darren Pai, Hawaiian Electric spokesperson.

Hawaiian Electric is also asking its larger commercial customers to voluntarily reduce electricity usage. System operators will also work on further reducing the demand for power by using Hawaiian Electric's demand response programs. These voluntary programs help lower the overall use of electricity by reducing the energy output of certain appliances or equipment, such as water heaters, for participating residential customers and non-essential lighting and heating or cooling systems for participating commercial customers.

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Figure 36. January 12, 2015; 4:35 PM News Release: Rotating Outages to be Initiated on O‘ahu (2–2)

January 12, 2015; 7:30 PM: Rotating Outages Initiated on O'ahu

Hawaiian Electric

NEWS RELEASE

CONTACT: (808) 223-9932 **FOR IMMEDIATE RELEASE**

Rotating outages initiated on O'ahu
Loss of power generators causes O'ahu outages
Customers are asked to conserve power

Update as of 7:30 p.m. – Hawaiian Electric system operators have initiated an outage impacting the area from Waialae Iki through Hawai Kai and portions of Waimanalo. The outage is expected to last approximately one hour.

Hawaiian Electric has restored power to customers in the Nuuanu-School Street area whose power was turned off from approximately 6:25 p.m. to 7:25 p.m. Any customers in the Nuuanu-School Street area who are still without power should call Hawaiian Electric's trouble line at 1-855-304-1212.

We sincerely apologize for the disruption and are making every effort to minimize the areas affected by outages. We continue to ask O'ahu customers to assist with the situation by conserving electricity use this evening.

Update as of 4:45 p.m. – Jan. 12, 2015 – Below is the planned rolling outage schedule (times are approximate). Hawaiian Electric system operators will evaluate demand for electricity and based on that, will determine the exact start time and whether all of the noted areas will be affected:

Begin	End	Area
5 p.m.	6 p.m.	Nuuanu-School Street area, all of Hawai'i Kai, sections of Waimanalo and Kahala
6 p.m.	7 p.m.	Most of Waipahu, sections of Pearl City, Kunia, Ewa Beach, Waiawa, Crestview, sections of Mililani
7 p.m.	8 p.m.	Pearl City, Waimalu, Waialua, Kuilima

HONOLULU, Jan. 12, 2015 – The loss of several generating units, including the largest on the island operated by independent power producer AES, required Hawaiian Electric to briefly shut off power for about 10 minutes to about 22,000 customers at approximately 1:50 p.m. The targeted emergency outages were necessary to avoid a more widespread outage or damage to the electric system from an imbalance of too much demand versus too little available generation.

The outages affected customers in areas across the island, including Kailua, Kaneohe, Maunawili, Wailupe, Halawa, Makalapa, Waipahu, and Waimano. Power to most affected customers was restored shortly after 2 p.m.

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Figure 37. January 12, 2015; 7:30 PM News Release: Rotating Outages Initiated on O'ahu (1–2)

Loss of power generators causes outages
Page 2 of 2
Jan. 12, 2015

The outage occurred after a 180-megawatt power plant operated by AES, an independent power producer, unexpectedly went out of service. In addition, the Kalaeloa Power Plant, also owned and operated by an independent power producer, has been providing less than half its maximum output of 208 megawatts as it goes through repairs for an equipment problem. One of

More…

Hawaiian Electric's generating units at the Kahe Power Plant, which normally produces 135 megawatts, is also off line after it unexpectedly experienced problems this morning.

Due to the loss of generation, Hawaiian Electric may need to initiate rolling outages starting at approximately 5 p.m. The outages would last approximately one hour and rotate through various parts of the island. This may be necessary to ensure the demand for power does not exceed the amount of available generation, which could result in an islandwide outage.

Hawaiian Electric is asking O'ahu customers to assist with the situation by conserving electricity use this evening, especially between 5 and 9 p.m. This precaution is intended to ensure sufficient power is available to meet the early evening peak demand for electricity. Suggested steps include turning off or lessening use of air conditioners, delaying hot showers and dishwashing activities, and minimizing cooking until later in the evening.

"We apologize for this disruption and thank our customers for their patience. We understand the evening hours, especially today with the football game, are an especially inconvenient time to cut back on electricity, but with everyone's help we hope to avoid an emergency situation," said Darren Pai, Hawaiian Electric spokesperson.

Hawaiian Electric is also asking its larger commercial customers to voluntarily reduce electricity usage. System operators will also work on further reducing the demand for power by using Hawaiian Electric's demand response programs. These voluntary programs help lower the overall use of electricity by reducing the energy output of certain appliances or equipment, such as water heaters, for participating residential customers and non-essential lighting and heating or cooling systems for participating commercial customers.

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Figure 38. January 12, 2015; 7:30 PM News Release: Rotating Outages Initiated on O'ahu (2–2)

January 12, 2015; 8:30 PM: Power Retried to O'ahu Customers

Hawaiian Electric

NEWS RELEASE

CONTACT: (808) 223-9932 **FOR IMMEDIATE RELEASE**

Power restored to O'ahu customers
No further outages expected tonight

Update as of 8:30 p.m. – At approximately 7:45 p.m., Hawaiian Electric restored power to all customers in the area from Waialae Iki through Hawai`i Kai and portions of Waimanalo. If any customer in these areas is still without power, we ask that they please call Hawaiian Electric's trouble line at 1-855-304-1212.

Hawaiian Electric does not expect to initiate any further outages for the rest of the night.

An estimated 27,000 customers were affected by the rolling outages, but no more than 14,000 at one time.

"We thank our customers for their patience, understanding and efforts to conserve power. We deeply apologize for the impact of these outages, especially to those who were watching tonight's football game," said Darren Pai, Hawaiian Electric spokesman.

Due to customer conservation, demand for power did not climb as high, allowing system operators to minimize the number and duration of the power outages.

Crews from Hawaiian Electric and independent power producer AES are working throughout the night to bring critical generating units back into service. Since those generating units may only be partially restored, it may be necessary to ask customers to conserve power during the evening peak on Tuesday to mitigate the need for additional rolling outages.

Update as of 7:30 p.m. – Hawaiian Electric system operators have initiated an outage impacting the area from Waialae Iki through Hawai`i Kai and portions of Waimanalo. The outage is expected to last approximately one hour.

Hawaiian Electric has restored power to customers in the Nuuanu-School Street area whose power was turned off from approximately 6:25 p.m. to 7:25 p.m. Any customers in the Nuuanu-School Street area who are still without power should call Hawaiian Electric's trouble line at 1-855-304-1212.

We sincerely apologize for the disruption and are making every effort to minimize the areas affected by outages. We continue to ask O'ahu customers to assist with the situation by conserving electricity use this evening.

More….

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Figure 39. January 12, 2015; 8:30 PM News Release: Power Retried to O'ahu Customers (1–3)

Loss of power generators causes outages
Page 2 of 3
Jan. 12, 2015

<u>Update as of 4:45 p.m. –</u> Jan. 12, 2015 – Below is the planned rolling outage schedule (times are approximate). Hawaiian Electric system operators will evaluate demand for electricity and based on that, will determine the exact start time and whether all of the noted areas will be affected:

Begin	End	Area
5 p.m.	6 p.m.	Nuuanu-School Street area, all of Hawai'i Kai, sections of Waimanalo and Kahala
6 p.m.	7 p.m.	Most of Waipahu, sections of Pearl City, Kunia, Ewa Beach, Waiawa, Crestview, sections of Mililani
7 p.m.	8 p.m.	Pearl City, Waimalu, Waialua, Kuilima

HONOLULU, Jan. 12, 2015 – The loss of several generating units, including the largest on the island operated by independent power producer AES, required Hawaiian Electric to briefly shut off power for about 10 minutes to about 22,000 customers at approximately 1:50 p.m. The targeted emergency outages were necessary to avoid a more widespread outage or damage to the electric system from an imbalance of too much demand versus too little available generation.

The outages affected customers in areas across the island, including Kailua, Kaneohe, Maunawili, Wailupe, Halawa, Makalapa, Waipahu, and Waimano. Power to most affected customers was restored shortly after 2 p.m.

The outage occurred after a 180-megawatt power plant operated by AES, an independent power producer, unexpectedly went out of service. In addition, the Kalaeloa Power Plant, also owned and operated by an independent power producer, has been providing less than half its maximum output of 208 megawatts as it goes through repairs for an equipment problem. One of

Hawaiian Electric's generating units at the Kahe Power Plant, which normally produces 135 megawatts, is also off line after it unexpectedly experienced problems this morning.

Due to the loss of generation, Hawaiian Electric may need to initiate rolling outages starting at approximately 5 p.m. The outages would last approximately one hour and rotate through various parts of the island. This may be necessary to ensure the demand for power does not exceed the amount of available generation, which could result in an islandwide outage.

Hawaiian Electric is asking O'ahu customers to assist with the situation by conserving electricity use this evening, especially between 5 and 9 p.m. This precaution is intended to ensure sufficient power is available to meet the early evening peak demand for electricity. Suggested steps include turning off or lessening use of air conditioners, delaying hot showers and dishwashing activities, and minimizing cooking until later in the evening.

"We apologize for this disruption and thank our customers for their patience. We understand the evening hours, especially today with the football game, are an especially inconvenient time to cut back on electricity, but with everyone's help we hope to avoid an emergency situation," said Darren Pai, Hawaiian Electric spokesperson.

Hawaiian Electric is also asking its larger commercial customers to voluntarily reduce electricity usage. System operators will also work on further reducing the demand for power by using

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Figure 40. January 12, 2015; 8:30 PM News Release: Power Retried to O'ahu Customers (2–3)

Hawaiian Electric's demand response programs. These voluntary programs help lower the overall use of electricity by reducing the energy output of certain appliances or equipment, such as water heaters, for participating residential customers and non-essential lighting and heating or cooling systems for participating commercial customers.

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Figure 41. January 12, 2015; 8:30 PM News Release: Power Retried to O'ahu Customers (3–3)

January 13, 2015: O‘ahu Customers Asked to Conserve Electricity

Hawaiian Electric

NEWS RELEASE

CONTACT: **(808) 223-9932** **FOR IMMEDIATE RELEASE**

O‘ahu customers asked to conserve electricity
Rolling outages not expected tonight

HONOLULU, Jan. 13, 2015 – Although the amount of available power generation on O‘ahu has improved somewhat from last night, Hawaiian Electric is asking customers to conserve energy this evening, between 5 and 9 p.m. Crews at an independent power producer and at Hawaiian Electric continue to work on restoring critical generating units back to full service. This precautionary measure is to help ensure sufficient power is available to meet the early evening peak demand for electricity.

Customers can help by turning off or reducing the use of air conditioners; delaying hot showers, laundry, and dishwashing; and minimizing cooking until later in the evening.

Based on current conditions, Hawaiian Electric does not expect to initiate any rolling outages tonight. Rolling outages were initiated Monday night to ensure the demand for power did not exceed the amount of available generation, which could have resulted in an islandwide outage.

“We thank our customers for their efforts to conserve power Monday night. We understand the difficulty this created for customers, but it made a real difference and helped us avoid more widespread outages. As a precaution, we’re asking for conservation again tonight because your support helps us avoid a possible emergency situation,” said Darren Pai, Hawaiian Electric spokesman.

Crews at independent power producer AES have been working on repairs to a boiler tube leak and have been able to partially restore their generating station. AES is currently producing 82 megawatts of power, compared to its normal maximum output of 180 megawatts. AES is the single largest generating unit on the island.

Hawaiian Electric crews are restoring to service a 135-megawatt generating unit at the Kahe Power Plant, but it is not expected to be able to operate at its full capability this evening. In addition, the independent power producer Kalaeloa Partners plant continues to operate at less than half its maximum output of 208 megawatts as it makes repairs to damaged turbine blades, a problem dating back to December 2014.

In addition, based on current weather forecasts, Hawaiian Electric does not expect to receive much production this evening from the wind farms located on the North Shore.

More…

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Figure 42. January 13, 2015 News Release: O‘ahu Customers Asked to Conserve Electricity (1–2)

O'ahu customers asked to conserve electricity
Page 2 of 2
Jan. 13, 2015

Hawaiian Electric is also asking its larger commercial customers to voluntarily reduce electricity usage. System operators will also further reduce the demand for power by using Hawaiian Electric's demand response programs. These voluntary programs help lower the overall use of electricity by reducing the energy output of certain appliances or equipment, such as water heaters, for participating residential customers and non-essential lighting and heating or cooling systems for participating commercial customers.

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FOLLOW US FOR THE LATEST:

Hawaiian Electric PO BOX 2750 / HONOLULU, HI 96840-0001

Figure 43. January 13, 2015 News Release: O'ahu Customers Asked to Conserve Electricity (2–2)

January 14, 2015: Call for Energy Conservation Lifted

Hawaiian Electric

NEWS RELEASE

CONTACT: (808) 223-9932 **FOR IMMEDIATE RELEASE**

Call for Energy Conservation Lifted

HONOLULU, Jan. 14, 2015 – Power plant crews have made significant progress on repairs to two of the largest generating units on Oahu. As a result, it is no longer necessary to ask customers to make extra conservation efforts in the evening.

Crews from AES, an independent power producer, are working on their 180-megawatt generating unit, which is the single largest generating unit on the island. Hawaiian Electric crews are also continuing to work on a 135-megawatt generating unit at the Kahe Power Plant. Both are expected to operate at about half their normal capacity while repairs are being completed. However, combined with the additional generation from other available units, based on the forecasted demand for power, this provides enough generation reserves to meet customers' energy needs.

"Our customers stepped up and made a difference by conserving energy the past couple of nights. We appreciate their help and thank them for their patience," said Darren Pai, Hawaiian Electric spokesman.

###

FOLLOW US FOR THE LATEST:

Hawaiian Electric PO BOX 2750 / HONOLULU, HI 96840-0001

Figure 44. January 14, 2015 News Release: Call for Energy Conservation Lifted

I. SOCIAL MEDIA POSTINGS

Here are examples of most of the messages we posted to our social media channels.

Twitter Messages

We posted tweets through our Twitter account on January 12, 2015 and January 13, 2015, listed in two tables. Each day's table lists the actual tweet (Twitter message), the number of re-tweets (a follower resending the tweet to their followers), and the number of Favorites each tweet received (an indication that the follower appreciate the tweet). Over the two days, we received 275 re-tweets and 59 Favorites.

Tweets are limited to 140 characters (including spaces and punctuation), thus the brevity and nonstandard abbreviations. References to specific followers begin with an @ sign (such as, @MinnaSugimoto).

January 12, 2015 Tweets

Twitter Message	RTs	Favorites
We're asking for your help to conserve energy tonight, especially between 5–9 p.m. Please read more: http://hwnelec.co/HdsQs.	19	2
Rotating outages to be initiated on Oahu starting approx. 5 pm; Pls see schedule: http://hwnelec.co/HdwVO	25	3
#OahuOutage: Nuuanu-School Street area, all of Hawaii Kai, sections of Waimanalo & Kahala now est. to be out at 5:30 pm.	12	–
Please conserve energy as it will help with the rotating blackouts #OahuOutage	2	2
#OahuOutage update: Please help conserve energy so we can delay the rotating blackouts. Mahalo.	10	4
Please spread the word to conserve energy so we can delay the rotating blackouts. #OahuOutage	10	3
Please share & help us delay the rotating outages by conserving energy. #OahuOutage	6	4
Pls cont to conserve energy. We are now est to start at 6 pm but it can be delayed if we cont to conserve. Mahalo. #OahuOutage	8	4
#OahuOutage update: Nuuanu-School Street area, all of Hawai'i Kai, sections of Waimanalo & Kahala scheduled for outage at around 6 pm.	8	2
So far so good. Mahalo for helping us. Pls cont to conserve energy so we can delay the rotating outages. #OahuOutage	8	–
Mahalo to our customers that are part of the EnergyScout water heater program. We cont to delay the rotating blackouts. #OahuOutage	2	1
Please help us delay the rolling outages by conserving energy. We're getting close to initiating but you can help us delay. Mahalo.	20	7
Pls do not do laundry at this time & help us conserve. #EnergyTips	6	–

Twitter Message	RTs	Favorites
@MinnaSugimoto Please spread the word to customers to conserve and we can delay the rolling blackouts. Mahalo.	1	1
Pls delay taking hot showers during this time so we can delay rolling outages. Mahalo cc: @DaraInHawaii @MinnaSugimoto	6	1
Pls delay cooking to help us delay rolling outages #energytips	4	–
#OahuOutage 625p: Nuuanu-School Street area are currently out of power & the outage will last about an hr.	15	2
630p #OahuOutage: Only customers in the Nuuano-School Street area are currently out of power at this time. Sorry for the inconvenience.	13	–
700p #OahuOutage: cust. in Hawaii Kai & sections of Waimanalo, Aina Haina & Kuliouou will be out of pwr in 20 min.	16	2
715p #OahuOutage: cust. in Hawaii Kai & sections of Waimanalo, Aina Haina, Niu Valley & Kuliouou will be out of pwr in 5–10 min.	4	–
720p: Downtown & Nuuanu customers will be back with power shortly. Mahalo for your patience. #OahuOutage	6	1
725p: DT/Nuuanu/Pacific Hts/Kalihi Valley restored #OahuOutage	11	2
725p #OahuOutage: cust. in Hawaii Kai & Laukahi, sections of Waimanalo, Waialae Iki Aina Haina, Niu Valley & Kuliouou are out of pwr.	15	4
#OahuOutage: If any cust. in the DT/Nuuanu/Pacific Hts/Kalihi Valley are still out of pwr, please call 1-855-304-1212 to report.	6	–
745p #OahuOutage update: Hawaii Kai & Laukahi, sect. of Waimanalo, Waialae Iki Aina Haina, Niu Valley & Kuliouou will be back up shortly.	10	3
We do not expect to initiate any further outages at this time. Mahalo to our customers for helping to conserve - http://hwnelec.co/HdRM7	14	8
Totals	*257*	*56*

Table 24. Twitter Messages: January 12, 2015

January 13, 2015

Twitter Message	RTs	Favorites
Aloha @islandfeversis -- currently, we are in the all-clear but if we do have any changes, we'll be sure to post these ASAP on social media.	1	1
@islandfeversis Thank you! Have a nice day.	–	–
We don't expect to initiate any rolling outages tonight, but are asking for customers' help with conserving energy: http://hwnelec.co/Hhcw1.	6	–
Mahalo @eriKaengle. We are asking for customers' help w/ conserving energy between 5–9p: http://hwnelec.co/HhcMt. Thank you!	1	1
.@lisn_808 We do not have any rolling outages planned. Please call in your specific address in Waipahu to our Trouble Line, 1-855-304-1212.	10	1
Totals	*18*	*3*

Table 25. Twitter Messages: January 13, 2015

Facebook/Google+ Posts

We posted on our Facebook/Google+ page coincident with four of our news releases. Duplicates of our posts with associated comments follow. Each duplicate contains metrics about the post: the number of customers who viewed the post, as well as the amount of Likes, Shares, and comments received. Each post is followed by the comments we received—some understanding, many critical, a few crass—and our replies and apologies when appropriate.

January 12, 2015, 3:30 PM Facebook/Google+ Post

Hawaiian Electric Companies added a new photo to the album: **Call for Energy Conservation**.
January 12 ·

Hawaiian Electric is asking Oahu customers to conserve electricity use this evening, especially between 5 and 9 p.m. This precaution is intended to ensure sufficient power is available to meet the early evening peak demand for electricity. Suggested steps include turning off or lessening use of air conditioners, delaying hot showers and dishwashing activities, and minimizing cooking until later in the evening. Due to loss of generation, Hawaiian Electric may need to initiate rolling outages starting at approximately 5 p.m. The outages would last approximately one hour and rotate through various parts of the island. This may be necessary to ensure the demand for power does not exceed the amount of available generation, which could result in an islandwide outage. Please read more here: http://hwnelec.co/Hdqw5.

2,938 people reached

Like · Comment · Share · 21 15 19

2,938 People Reached

101 Likes, Comments & Shares

41 Likes	21 On Post	20 On Shares
38 Comments	23 On Post	15 On Shares
22 Shares	19 On Post	3 On Shares

398 Post Clicks

162 Photo Views	21 Link Clicks	215 Other Clicks

NEGATIVE FEEDBACK

3 Hide Post	0 Hide All Posts
0 Report as Spam	0 Unlike Page

Hawaiian Electric Companies Donna and MaryAnn, we'll do our best to minimize the inconvenience. Thank you for your patience and your kokua with conservation, as every little bit will help. Mahalo.
Like · Reply · 2 · Commented on by Minnie Fukuda [?] · January 12 at 4:24pm

Figure 45. Facebook/Google+ Post: January 12, 2015; 3:50 PM (1–3)

Donna Asinsin I read the updates and Mahalo for all what you folks do..
Like · January 12 at 5:40pm

Hawaiian Electric Companies Aloha Donna - Please spread the word to conserve energy as it will help us to delay the rotating outages. Mahalo for your support.
Like · 1 · Commented on by Minnie Fukuda [?] · January 12 at 5:42pm

Donna Asinsin Already doing my part when I saw the notice on fb...
Unlike · 1 · January 12 at 5:43pm

Write a reply...

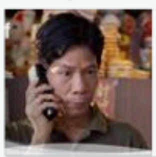
Brad Rockwell I've been there before... providing power on an island is not easy and sometimes multiple bad things align to create a situation nobody likes. Good luck, HECO.
Like · Reply · 5 · January 12 at 4:34pm

Hawaiian Electric Companies Mahalo Brad for your understanding.
Like · Commented on by Minnie Fukuda [?] · January 12 at 4:39pm

Write a reply...

Mercedes Harwood-Tappé Where will the outages take place exactly? All over each grid or only some?
Like · Reply · January 12 at 4:28pm

Hawaiian Electric Companies Aloha Mercedes - We will be providing an update on the planned rolling outages shortly on hawaiianelectric.com. Mahalo.



Hawaiian Electric: Home Channel Page
The Hawaiian Electric Companies are...
HAWAIIANELECTRIC.COM | BY HAWAIIAN E...

Like · Remove Preview · 1 · Commented on by Minnie Fukuda [?] · January 12 at 4:36pm · Edited

Mercedes Harwood-Tappé Thank you for the quick response! I will check back then! I appreciate it.
Like · January 12 at 4:34pm

Hawaiian Electric Companies Aloha Mercedes- Another post has been made with the approximate schedule and locations.
Like · 2 · Commented on by Minnie Fukuda [?] · January 12 at 5:07pm

Mercedes Harwood-Tappé Thank you for the update
Like · January 12 at 5:23pm

Write a reply...

Figure 46. Facebook/Google+ Post: January 12, 2015; 3:50 PM (2–3)

MaryAnn Suan Dearmore Really HECO!!! There's a National Championship Football Game going on with Hawai'i 1st Heisman Trophy Winner!
Like · Reply · 6 · January 12 at 4:04pm

Jeremiah Skurtu Just turn off waikiki, rest of us can have electricity. .. tourists always asking for the real hawaii experience
Like · Reply · 3 · January 12 at 7:22pm

Sweet Tee YOU SUCK HECO!!!!!!!!
Like · Reply · 2 · January 12 at 6:52pm

Royce Wright Jr. So Hawaii pays the most expensive electric in the USA, about twice the amount of the 2nd highest State (2o cents kwh), yet you guys can't seem to muster up the cash to keep a steady supply...
Like · Reply · 2 · January 12 at 4:53pm

Donna Asinsin Ummm,yeah..gonna be really pissed if no can watch....
Like · Reply · 2 · January 12 at 4:09pm

Jerry Maltezo Yeah let's plan another on Super Bowl Sunday too!!!
Like · Reply · 1 · January 12 at 5:16pm

Vaughn Travis REALLY AND I PAY $550 A MONTH FOR SHIT THATS GONNA RUN OUT?!!!WTF!!!
Like · Reply · 1 · January 12 at 4:46pm

Sweet Tee HECO YOU SUCK!!!!!
Like · Reply · January 12 at 9:20pm

Nani Rozkiewicz Yeah couldn't you guys have started this an hour later and not during the begining of the 3rd quarter of the BCS Championship?! I understand that this needed to get done but really would an hour have mattered?? This is like doing this during Super Bow... See More
Like · Reply · January 12 at 7:56pm

Jeremiah Skurtu Thought only supposed to be an hour... it's now been 1 and a half
Like · Reply · January 12 at 7:24pm

Annette Viernes I'm waiting for the rotation. It has not happened yet!!!!!
Like · Reply · January 12 at 7:14pm

Karen Lacro Maybe if stepped up on approving the solar panel switch, this wouldn't be needed.
Like · Reply · January 12 at 5:38pm

Figure 47. Facebook/Google+ Post: January 12, 2015; 3:50 PM (3–3)

January 12, 2015, 7:45 PM Facebook/Google+ Post

Hawaiian Electric Companies
January 12 · Edited ·

UPDATE as of 7:45 pm: Customers in Hawaii Kai & sections of Waialae Iki, Waimanalo, Aina Haina & Kuliouou are now restored. If you are still out of power, please call 1-855-304-1212 to report your outage.

UPDATE as of 7:25 pm: Customers in Hawaii Kai & sections of Waialae Iki, Waimanalo, Aina Haina & Kuliouou are currently out of power. This will last approximately an hour. Customers in Downtown & Nuuanu-School Street area are now restored.

UPDATE as of 7:15 pm: Customers in... See More

6,608 people reached

Like · Comment · Share · 15 23 41

6,608 People Reached

180 Likes, Comments & Shares

41 Likes	15 On Post	26 On Shares
83 Comments	30 On Post	53 On Shares
56 Shares	41 On Post	15 On Shares

911 Post Clicks

274 Photo Views	0 Link Clicks	637 Other Clicks

NEGATIVE FEEDBACK

2 Hide Post	1 Hide All Posts
0 Report as Spam	0 Unlike Page

Nicci-Linn Likolehua Freitas That's really stupid. Why not during the day when the majority is at work or school. Not in the 4th quarter of the bloody BCS bowl
Like · Reply · 2 · January 12 at 6:33pm · Edited

> **Hawaiian Electric Companies** During the day, the demand is typically lower. We were trying to delay as long as we could but we had to initiate the first rotating outage. Sorry for the inconvenience.
> Like · 1 · Commented on by Minnie Fukuda [?] · January 12 at 6:37pm
>
> Write a reply...

Alden Starr Will this affect Pearlridge shopping center also?
Like · Reply · January 12 at 5:48pm

> **Hawaiian Electric Companies** Aloha Alden- No Pearlridge Center will not be affected. Mahalo.
> Like · Commented on by Minnie Fukuda [?] · January 12 at 5:50pm
>
> Write a reply...

Figure 48. Facebook/Google+ Post: January 12, 2015; 7:45 PM (1–3)

Mike Low HECO you get no likes...but probably a lot of hates for the lack of a backup plan (no, rolling blackouts is not a backup), especially during the championship game. You can try to separate yourselves from independent power producer AES all you want, but you're as equally responsible for this mess. All these rate hikes and you still can't get your act together! smh
Like · Reply · 11 · January 12 at 5:33pm

> **Hawaiian Electric Companies** Aloha Mike- We respect your opinion and sorry for the inconvenience.
> Like · Commented on by Minnie Fukuda [?] · January 12 at 5:35pm
>
> View more replies

Solomon Manuia Hawaiian Electric thanks for the hard an awsome work done the super crew of
Unlike · Reply · 1 · January 13 at 5:25pm

Sweet Tee HECO YOU SUCK!!!!!!
Like · Reply · 6 · January 12 at 6:40pm

Juliet Kim screw u hawaiian electric! in the dark with a 2 yr old and a 3 month old seems like forever ! especially dinner time! not f'ing cool at all!
Like · Reply · 4 · January 12 at 6:51pm

Randall Ushijima HECO owes me a small refund! Rolling blackout during the game? You suck!
Like · Reply · 4 · January 12 at 6:45pm

Daniel Lee-Soon Fail.
Like · Reply · 4 · January 12 at 6:33pm

Jody Teruya Heco - please plan in advance and not have scheduled blackouts during the AFC/NFC Championships and the SuperBowl! Thank you!
Like · Reply · 3 · January 12 at 7:15pm

Kristin Momoa Why wasn't Waikiki FIRST on the list or are the Tourists and Prada more important than us residents?
Like · Reply · 3 · January 12 at 7:02pm

> 1 Reply

Colleen Ahia What happens when we have someone on oxygen and need electricity? We live in an 8 unit apt. building!
Like · Reply · 3 · January 12 at 6:56pm

Myra Caneso Rodriguez Not a good idea!!! Worst timing on a BCS night!
Like · Reply · 3 · January 12 at 6:53pm · Edited

Dianne Sumida HECO, you need to specify exactly what area. I live in Pauoa which is not Nuuanu and we have no power. If we are part of your rolling blackout, then you should mention our area and not lump us in with Nuuanu.
Like · Reply · 2 · January 12 at 6:56pm

Jody Teruya Listening on a portable radio is just as exciting as watching it on tv...NOT!
Like · Reply · 2 · January 12 at 6:46pm

Figure 49. Facebook/Google+ Post: January 12, 2015; 7:45 PM (2–3)

Kathy Yamamoto Thanks Heco! Now we can't watch the end of the game!!
Like · Reply · 2 · January 12 at 6:27pm

Jeremiah Skurtu You suck HECO
Like · Reply · 1 · January 12 at 7:20pm

Drew Niles Thank you so much Hawaiian Electric! In your infinite wisdom, you have decided to spare me from an Ohio State win. In the future, I won't be so quick to curse your name. Now I understand that my HUNDREDS of dollars per month are financing pure GENIUS!!!
Like · Reply · 1 · January 12 at 7:17pm

Nani Rozkiewicz Yeah you could have waited an hour before doing this black out crap!!! I missed the Bcs championship !!! One hour would not have hurt u guys!!!! Heco sucks!!!
Like · Reply · 1 · January 12 at 7:13pm

Verna Kuulei Vaughan Epic Fail!
Like · Reply · 1 · January 12 at 6:57pm

Terry Brewer HECo sucks. Always has always will...
Like · Reply · January 12 at 10:11pm

Dane Teruya Fail!
Like · Reply · January 12 at 8:18pm

Figure 50. Facebook/Google+ Post: January 12, 2015; 7:45 PM (3–3)

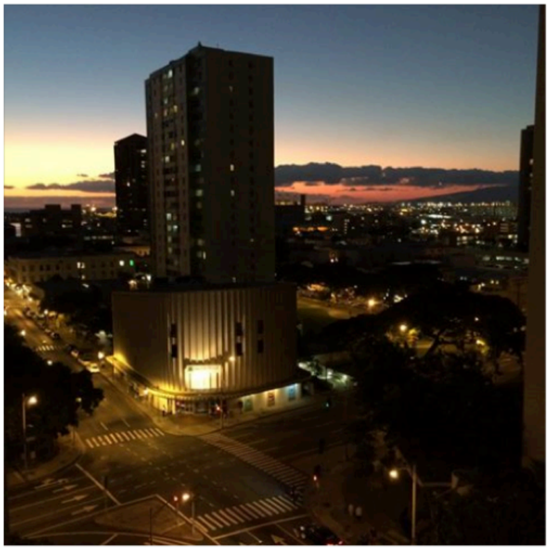
January 12, 2015, 8:30 PM Facebook/Google+ Post

Hawaiian Electric Companies
January 12 ·

Update as of 8:30 p.m. – At approximately 7:45 p.m., we restored power to all customers in the area from Waialae Iki through Hawaii Kai and portions of Waimanalo. Any customers in these areas who are still without power should call Hawaiian Electric's trouble line at 1-855-304-1212.

Hawaiian Electric does not expect to initiate any further outages for the rest of the night.

An estimated 27,000 customers were affected by the rolling outages, but no more than 14,000 at one time... See More



1,428 people reached

Like · Comment · Share · 30 4

1,428 People Reached

53 Likes, Comments & Shares

39 Likes	30 On Post	9 On Shares
6 Comments	6 On Post	0 On Shares
8 Shares	1 On Post	7 On Shares

147 Post Clicks

84 Photo Views	0 Link Clicks	63 Other Clicks

NEGATIVE FEEDBACK

0 Hide Post	0 Hide All Posts
0 Report as Spam	0 Unlike Page

Hawaiian Electric Companies Shunny, at the moment we all in all-clear mode. If anything changes we will be posting updates here and on our Twitter account, @HwnElectric. Mahalo.
Like · Reply · Commented on by Minnie Fukuda [?] · January 13 at 7:54am

Kim Bermudez Love your service! But did you have to start the rolling outages as the rice was cooking? 😃
Like · Reply · January 13 at 9:43am

> **Hawaiian Electric Companies** Our apologies, Kim! Thank you very much for your patience and understanding.
> Like · Commented on by Hootsuite [?] · January 13 at 9:48am
>
> **Kim Bermudez** You guys are da best!
> Like · January 13 at 10:05am
>
> Write a reply...

Shunny Shunshun Who will be affected on Tuesday and when/how will we find out. We were told Waipahu would have outages tonight but did not have any.
Like · Reply · January 12 at 10:25pm

Figure 51. Facebook/Google+ Post: January 12, 2015; 8:30 PM

January 13, 2015 Facebook/Google+ Post

Hawaiian Electric Companies added a new photo to the album: **1/13/15: Oahu Customers Asked to Conserve Energy.**
January 13 ·

Based on current conditions, Hawaiian Electric does not expect to initiate any rolling outages tonight. Although the amount of available power generation on Oahu has improved somewhat from last night, we are asking customers to conserve energy this evening, between 5 and 9 p.m. Crews at an independent power producer and at Hawaiian Electric continue to work on restoring critical generating units back to full service. This precautionary measure is to help ensure sufficient pow... See More

799 people reached

Like · Comment · Share · 17 3 1

799 People Reached

29 Likes, Comments & Shares

17 Likes	17 On Post	0 On Shares
7 Comments	6 On Post	1 On Shares
5 Shares	2 On Post	3 On Shares

41 Post Clicks

18 Photo Views	1 Link Clicks	22 Other Clicks

NEGATIVE FEEDBACK

0 Hide Post	0 Hide All Posts
0 Report as Spam	0 Unlike Page

Hawaiian Electric Companies Crews report that the Aiea outage has been fully restored. Mahalo.
Like · Reply · Commented on by Minnie Fukuda [?] · January 13 at 8:42pm · Edited

Kū Lia Lee-Anne Kathryn Hardy looks like not enough people conserved tonight 🙁
Like · Reply · January 13 at 8:01pm

> **Hawaiian Electric Companies** Aloha Ku Lia. We do not have any planned rolling outages tonight, but we are experiencing an outage in a portion of Aiea. If you are experiencing an Oahu outage, please call our Trouble Line at 1-855-304-1212. Mahalo.
> Like · 1 · Commented on by Minnie Fukuda [?] · January 13 at 8:16pm

Figure 52. Facebook/Google+ Post: January 13, 2015 (1–2)

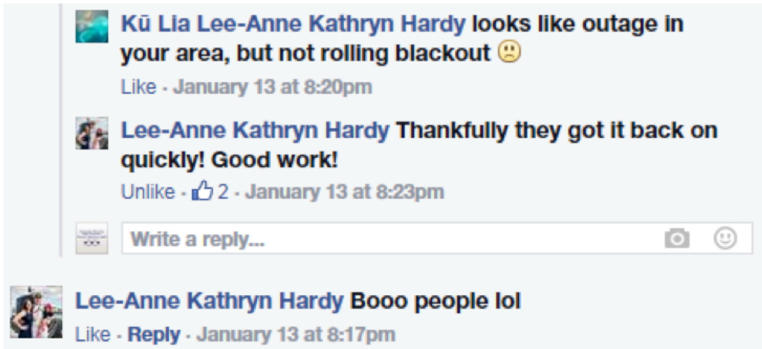


Figure 53. Facebook/Google+ Post: January 13, 2015 (2–2)

Customer Posts Supporting Our Lessons Learned

Customer responses to our social media posts helped us identify lessons to be learned for future outages.

Earlier Notification

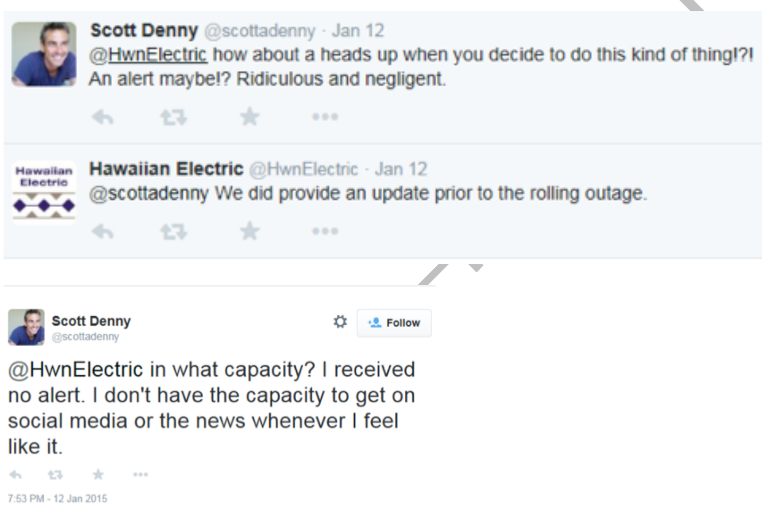
These posts enabled us to realize that we must notify customers earlier about when the actual outages are scheduled to occur.

@nkvball: @HwnElectric great give us less than 20 min warning when we are stuck in traffic #EpicFail

@nkvball: @HwnElectric you didn't spread the word well enough!!!!

@gtrchick1: @HwnElectric @nkvball only saw on Tv 5 in ago. If my power was cut at 5:30 I would have NO NOTICE

@wilburwong: @HwnElectric the game! Wish we could have advanced notice as well. Was in the process of cooking dinner for two little kids. Now we're stuck


Scott Denny @scottadenny · Jan 12
@HwnElectric how about a heads up when you decide to do this kind of thing!?! An alert maybe!? Ridiculous and negligent.

Hawaiian Electric @HwnElectric · Jan 12
@scottadenny We did provide an update prior to the rolling outage.

Scott Denny
@scottadenny
Follow
@HwnElectric in what capacity? I received no alert. I don't have the capacity to get on social media or the news whenever I feel like it.
7:53 PM - 12 Jan 2015

Figure 54. Customer Social Media Posts: Earlier Notification

Specific Outage Locations

Customer posts made us realize that we must be much more specific about the actual locations where outages are going to occur.

@wilburwong: @HwnElectric my area isn't listed. Or at least I never considered my street Nuuanu. I'm two blocks from there and east.

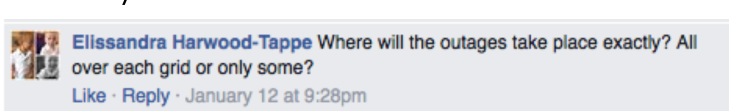

Elissandra Harwood-Tappe Where will the outages take place exactly? All over each grid or only some?
Like · Reply · January 12 at 9:28pm

Figure 55. Customer Social Media Posts: Specific Outage Locations

Customers Misunderstanding Our Intent

These posts showed us that many customer misunderstood why and when the outages would occur.

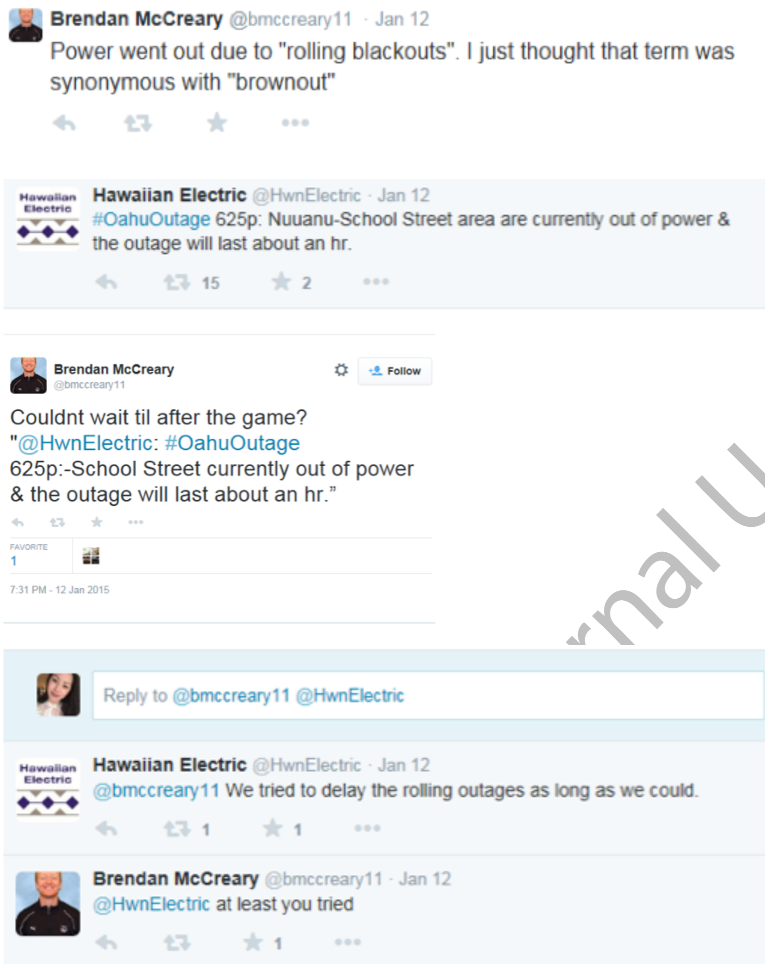


Figure 56. Customer Social Media Posts: Customers Misunderstanding Our Intent

Positive Customer Response

Many customer posts enabled us realize that engaging them through our social media channels helps establish a much needed conversation about the situation.

Oskar Garcia @oskargarcia · Jan 12
How's the power? MT @MilekaLincoln: #Oregon XP good & @StLouisHawaii alumni feeling good too! #Mariota madness in here!! #CFBChampionship

Mileka Lincoln @MilekaLincoln · Jan 12
@oskargarcia @StLouisHawaii SO far SO GOOD! *fingers crossed* ...apparently @HwnElectric has delayed their rollout. We'll see how it goes!
1

Hawaiian Electric @HwnElectric · Jan 12
@MilekaLincoln As long as customers help us conserve energy then we can delay the outages. @oskargarcia @StLouisHawaii
4 3

Mileka Lincoln @MilekaLincoln Follow
CONSERVE! "@HwnElectric: @MilekaLincoln As long as customers help us conserve energy we can delay the outages. @oskargarcia @StLouisHawaii"
FAVORITE 1

Mileka Lincoln @MilekaLincoln · Jan 12
We still have power but just in case:PB&J w/ red white for dinner. Conserving power's DELISH #OahuOutage @HwnElectric
Mileka Lincoln

Colin Sato @colinsato · Jan 12
@HwnElectric no problem, thanks for keeping everybody up-to-date.
Details

Colin Sato @colinsato · Jan 12
@HwnElectric Okay, thanks. Earlier message was a little confusing. I now understand that now = not and it makes more sense.
Details

Colin Sato @colinsato · Jan 12
@HwnElectric i've been waiting in town, hoping I would arrive when power is back on.
Details

Colin Sato @colinsato · Jan 12
@HwnElectric thanks... So, power is currently out? Is there a timetable for restoration? Just worried about getting in the garage.
Details

Figure 57. Customer Social Media Posts: Positive Customer Response (1–2)

JJ Kam @RukusAlliance · Jan 12
@HwnElectric awesome, thanks for the update!
Details

JJ Kam @RukusAlliance · Jan 12
@HwnElectric is Pacific Palisades going to be out anytime tonight?
Details

Nancy Bueno @goformiles · Jan 12
@HwnElectric Thank you !! Been prepping for the lights going out.
Details

Nancy Bueno @goformiles · Jan 12
@HwnElectric when will pearl city be affected
Details

@LourdesMadriaga: @HwnElectric No worries. We're actually looking forward to it. Kids love the flashlights lol

Figure 58. Customer Social Media Posts: Positive Customer Response (2–2)