A. Commission Order Cross Reference

In Docket No. 2011-0206, Order No. 32053 entitled "Ruling on RSWG Work Product", the Hawai'i Public Utilities Commission ordered Hawaiian Electric:

> "to file a Power Supply Improvement Plan (PSIP) with the commission within 120 days of the date of this Decision and Order, among other reasons, to provide plans as to how HECO intends to accomplish the integration of substantial amounts of variable renewable energy resources, in a reliable and economic manner, without significant curtailments of existing or future renewable resources."[56]

The Order listed a number of component plans, each with a number of issues to consider. The Order also listed other stipulations—energy storage and ancillary services—to be analyzed and evaluated.

Presented here is a cross reference between the issues raised in the Commission's Order and the locations in this PSIP where they are addressed.

[56] Docket No. 2011-0206, Order No. 32053, Section II. C. 2. iii. 11.; p91.

COMPONENT PLANS

Component Plan	PSIP Heading	Page
Fossil Generation Retirement Plan	Plan for Retiring Fossil Generation	5-21
Generation Flexibility Plan	Increasing Operational Flexibility of Existing Steam Generators Utilization of Renewable Energy	5-12 5-25
Must-Run Generation Reduction Plan	Increasing Operational Flexibility of Existing Steam Generators	5-12
Environmental Compliance Plan	Environmental Compliance	5-60
Key Generator Utilization Plan	Key Generator Utilization Plan	5-16
Optimal Renewable Energy Portfolio Plan	Hawaiian Electric: Unprecedented Levels of Renewable Energy	5-11
Generation Commitment and Economic Dispatch Review	Appendix N	N-1

Table A-1. Component Plan Cross Reference

FURTHER ACTION: ENERGY STORAGE

Further Action	PSIP Heading	Page
Energy Storage	Energy Storage Plan	5-27

Table A-2. Further Action: Energy Storage Cross Reference

ANCILLARY SERVICES

Ancillary Services	PSIP Heading	Page
Must Run Generation Reduction Plan	Increasing Operational Flexibility of Existing Steam Generators	5-12
Generation Commitment and Economic Dispatch Review	Appendix N	N-1

Table A-3. Ancillary Services Cross Reference

B. Glossary and Acronyms

This Glossary and Acronym Appendix contains the terms used throughout the Power Supply Improvement Plan (PSIP), the Distributed Generation Interconnection Plan (DGIP), and the Integrated Interconnection Queue (IIQ). The Appendix clarifies the meaning of these terms, and helps you better understand the concepts described by these terms.

A

Adequacy of Supply

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

Advanced DER Technology Utilization Plan (ADERTUP)

A plan within the Distributed Generation Improvement Plan (DGIP) that sets forth the near, medium, and long-term plans by which customers would install, and utilities would utilize, advanced technologies to mitigate adverse grid impacts of distributed generation (DG) photovoltaics (PV).

Advanced Distribution Management System (ADMS)

A single system that includes an Outage Management System (OMS), Distribution Management System (DMS), and Distribution SCADA components and functionalities all in one platform, with a single user interface for the operator. ADMS will be used to help manage and integrate the new technologies and applications to be deployed as part of the utility's grid modernization program.

Advanced Inverter

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

Advanced Metering Infrastructure (AMI)

A primary component of a modern grid that provides two-way communications between the customer premises and the utility. An AMI is a necessary prerequisite to the interactions with advanced inverters, customer sited storage, demand response through direct load control, and EVs.

Alternating Current (AC)

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

Ancillary Services

Services that supplement capacity as needed in order to meet demand or correct deviations in frequency. These include reserves, black start resources, and frequency response.

As-Available Renewable Energy

See Variable Renewable Energy on page B-35.

Avoided Costs

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

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

B

Baseload

The minimum electric or thermal load that is supplied continuously over a period of time. See also Load, Electric on page B-19.

Baseload Capacity

See Capacity, Generating on page B-4.

Baseload Generation

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

Battery Energy Storage Systems (BESS)

Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, or other utility or customer functions. See also Storage on page B-31.

Black Start

The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

British Thermal Unit (Btu)

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

Buy-All/Sell-All

Tariff structure for DER under which customers would sell their entire DG output to the utility and purchase all of their requirements from the utility. This structure requires a two-meter system, with one meter to monitor grid import/export and one to monitor generation from the PV system.

C

Capacitor

A device that helps improve the efficiency of the flow of electricity through distribution lines by reducing energy losses. This is accomplished by the capacitor's ability to correct AC voltage so that the voltage is in phase with the AC current. Capacitors are typically installed in substations and on distribution system poles.

Capacity Factor (cf)

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

Capacity, Generating

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

Baseload Capacity: Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Baseload capacity typically operates at high annual capacity factors, for example greater than 60%.

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

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

Intermediate Capacity: Flexible generators able to efficiently vary their output across a wide band of loading conditions. Also known as Cycling Capacity. Typically annual capacity factors for intermediate duty generating units range from 20% to 60%.

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

Peaking Capacity: Generators typically called on for short periods of time during system peak load conditions. Annual capacity factors for peaking generation are typically less than 20%.

Capital Expenditures

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

Carbon Dioxide (CO_2)

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

Combined Cycle (CC)

A combination of combustion turbine- and steam turbine-driven electrical generators, where the combustion turbine exhaust is passed through a heat recovery waste heat boiler which, in turn, produces steam which drives the steam turbine.

2x1 Combined Cycle: A configuration in which there are two combustion turbines, one heat recovery waste heat boiler, and one steam turbine. The combustion turbines produce heat for the single waste heat boiler, which in turn produces steam that is directed to the single steam turbine.

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

Single-Train Combined Cycle (STCC): A configuration in which there is one combustion turbine, one heat recovery waste heat boiler, and one steam turbine.

Combined Heat and Power (CHP)

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

Combustion Turbine (CT)

Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power. Combustion turbines typically use natural gas or liquid petroleum fuels to operate.

Commercial and Industrial Direct Load Control (CIDLC)

A demand response program that provides financial incentives to qualified businesses for participating in demand control events. Such a program is designed for large commercial and industrial customers.

Commercial and Industrial Dynamic Pricing (CIDP)

A demand response program that provides tariff-based dynamic pricing options for electrical power to commercial and industrial customers. CIDP encourages customers to reduce demand when the overall load is high.

Conductor Sag

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

Connected Load

See Load, Electric on page B-19.

Contingency Reserve

The reserve deployed to meet contingency disturbance requirements, the largest single resource contingency on each island.

Curtailment

Cutting back on variable resources during off-peak periods of low electricity use in order to keep generation and consumption of electricity in balance.

D

Daytime Minimum Load (DML)

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

Demand

The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in Kilowatts (kW = 1 Kilowatt = 1000 watts), while energy use is usually measured in Kilowatt-hours (kWh = Kilowatts x hours of use = Kilowatt-hours). Load is considered synonymous with demand. (See also Load, Electric on page B-19.)

Demand Charge

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

Demand Response (DR)

Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. The underlying objective of demand response is to actively engage customers in modifying the demand for electricity, in lieu of a generating plant supplying the demand.

> ***Load Control:*** Includes direct control by the utility or other authorized third party of customer end-uses such as air conditioners, lighting, and motors. Load control may entail partial or load reductions or complete load interruptions. Customers usually receive financial consideration for participation in load control programs.
>
> ***Price Response:*** Refers to programs that provide pricing incentives to encourage customers to change their electricity usage profile. Price response programs include real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates, and demand bidding or buyback programs.

Demand-Side Management (DSM)

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

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

Hawaiʻi's resource center for economic and statistical data, business development opportunities, energy and conservation information, and foreign trade advantages. DBEDT's mission is to achieve a Hawaiʻi economy that embraces innovation and is globally competitive, dynamic and productive, providing opportunities for all Hawaiʻi's citizens. Through our attached agencies, we also foster planned community development, create affordable workforce housing units in high-quality living environments, and promote innovation sector job growth.

Department of Land and Natural Resources (DLNR)

A department within the Hawaiʻi state government responsible for managing state parks and other natural resources.

Direct Current (DC)

A department within the Hawaiʻi state government responsible for managing Hawaiʻi's unique natural and cultural resources. Also oversees state-owned and state conservation lands.

Distributed Energy Resources Technical Working Group (DER-TWG)

A working group to be formed as a review committee for DER-related technical assessments.

DG 2.0

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

Direct Current (DC)

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

Direct Load Control (DLC)

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

Direct Transfer Trip

A protection mechanism that originates from station relays in response to a substation event.

Dispatchable Generation

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

Distributed Circuit Improvement Implementation Plan (DCIIP)

A plan within the Distributed Generation Interconnection Plan (DGIP) that summarizes the specific strategies and action plans, including associated costs and schedules, to implement circuit upgrades and other mitigation measures to increase capacity of electrical grids to interconnect additional distributed generation.

Distributed Energy Resources (DER)

Non-centralized generating and storage systems that are co-located with energy load.

Distributed Energy Storage

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

Distributed Generation (DG)

A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid. Distributed generation can serve as a primary or backup energy source and can use various technologies, including combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics. Also known as a Distributed Energy Resource (see page B-9).

Distributed Generation Interconnection Capacity Analysis (DGICA)

A plan within DGIP to proactively identify distribution circuit capacity constraints to the safe and reliable interconnection of distributed generation resources. Includes system upgrade requirements necessary to increase circuit interconnection capability in major capacity increments.

Distribution Automation (DA)

Programs to allow monitoring and control of all distribution level sources, as well as the automation of feeders to provide downstream monitoring and control.

Distribution Circuit Monitoring Program (DCMP)

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

Distribution Circuit

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

Distribution Transformer

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

Disturbance Ride-Through

The capability of DG systems to remain connected to the grid under non-standard voltage levels.

Droop

The amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop.

Dual-Train Combined Cycle (DTCC)

See Combined Cycle on page B-5.

E

Economic Dispatch

The start-up, shutdown, and allocation of load to individual generating units to effect the most economical production of electricity for customers.

Electric Power Research Institute (EPRI)

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

Electric Vehicle (EV)

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

Electricity

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

Energy

The ability to produce work, heat, light, or other forms of energy. It is measured in watt-hours. Energy can be computed as capacity or demand (measured in watts), multiplied by time (measured in hours). For example, a 1 megawatt (one million watts) power plant running at full output for 1 hour will produce 1 megawatt-hour (one million watt-hours or 1000 kilowatt-hours) of electrical energy.

Emissions

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

Energy Efficiency DSM

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

Energy Efficiency Portfolio Standard (EEPS)

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

Energy Excelerator

A program of the Pacific International Center for High Technology Research that funds seed-stage and growth-stage startups with compelling energy solutions and immediate applications in Hawaiʻi, helping them succeed by providing funding, strategic relationships, and a vibrant ecosystem.

Energy Management System (EMS)

A computer system,including data-gathering tools used to monitor and control electrical generation and transmission.

Expense

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

Export Model

A model for DG PV interconnection in which co-incident self-generation and usage is not metered, excess energy is exported to the grid, and energy is imported to meet additional customer needs.

F

Feeder

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

Firm Capacity

See Capacity, Generating on page B-4.

Feed-In-Tariff (FIT) Program

A FIT program specific to Hawaiian Electric, under guidelines issued by the Hawaiʻi Public Utilities Commission, which provides for customers to sell all the electric energy produced to the electric company.

Feed-In-Tariff (FIT)

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

First-In-First-Out (FiFo)

The policy for clearing the DG interconnection queues, under which applications are processed in the order in which they were received.

Flicker

An impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.

Flywheel

See Storage one page B-31.

Forced Outage

See Outage on page B-23.

Forced Outage Rate

See Outage on page B-23.

Fossil Fuel

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

Frequency

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

Frequency Regulation

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

Full-Forced Outage

See Outage on page B-23.

Full Service Customer

Any residential or commercial customer that imports the entirety of their energy demands from the grid, and does not self-consume or export any energy derived from distributed energy resources co-located with their load.

G

Generating Capacity

See Capacity, Generating on page B-4.

Generation (Electricity)

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

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

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

Generator (Electric)

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

Geographic Information System (GIS)

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

Gigawatt (GW)

A unit of power, capacity, or demand equal to one billion watts.

Gigawatt-hour (GWh)

A unit of electric energy equal to one billion watt-hours.

Grandfather

To exempt a class of customers from changes to the laws or regulations under which they operate.

Greenhouse Gases (GHG)

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

Grid (Electric)

An interconnected network of electric transmission lines and related facilities.

Grid Modernization

The full suite of technologies and capabilities—including the data acquisition capabilities, controlling devices, telecommunications, and control systems—necessary to operate the utility's modernized electric grid. This includes Advanced Metering Infrastructure (AMI) with two-way communications and all the components to implement an Advanced Distribution Management System/Energy Management System. Additional components might include Volt-VAR Optimization (VVO); demand response; control of DG (curtailment and other); adaptive relaying (dynamic load shed); transformer monitoring; and potentially other advanced analytics, reporting, and monitoring capabilities.

Gross Generation

See Generation (Electricity) on page B-14.

Ground Fault Overvoltage

A transient overvoltage issue that occurs when the neutral of a wye grounded system shifts, causing a temporary overvoltage on the unfaulted phase.

Grounding Transformer

A transformer that provides a safe path to ground.

H

Hawai'i Public Utilities Commission (PUC)

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

Hawaiʻi Revised Statute (HRS)

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

Heat Rate

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

High Voltage Direct Current (HVDC)

An electric power transmission system that uses direct current, rather than alternating current, for bulk transmission.

I

Impacts

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

Impedance

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

Independent Power Producer (IPP)

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

Installed Capacity

See Capacity, Generating on page B-4.

Integrated Demand Response Portfolio Plan (IDRPP)

A Comprehensive Demand Response program proposal filed by the Companies with the Hawai'i Public Utilities Commission on July 28, 2014.

Integrated Interconnection Queue (IIQ)

Recommendations and plan for implementing and organizing an Integrated Interconnection Queue across all DG programs as directed by the Hawaiʻi Public Utilities Commission in Order 32053, to be filed on August 26, 2014.

Integrated Resource Plan (IRP)

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

Interconnection Charge

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

Interconnection Requirements Study (IRS)

Studies conducted by the Hawaiian Electric Companies on specific DG interconnection requests that may require mitigation measures to ensure circuit stability.

Intermediate Capacity

See Capacity, Generating on page B-4.

Intermittent Renewable Energy

See Variable Renewable Energy on page B-35.

Inverter

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

Islanding

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

K

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

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

L

Laterals
Lines branching off the primary feeder on a distribution circuit.

Levelized Cost of Energy (LCOE)
The price per kilowatt-hour in order for an energy project to break even; it does not include risk or return on investment.

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

Liquefied Natural Gas (LNG)
Natural gas that has been cooled until it turns liquid, in order to make storage and transport easier.

Live-Line Block Closing
Restrictions on the re-closing of feeders with interconnected DG PV systems based on line voltage levels.

Load, Electric

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

Baseload: The minimum load over a given period of time.

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

Load Balancing

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

Load Control Program

A program in which the utility company offers some form of compensation (for example, a bill credit) in return for having permission to control a customer's air conditioner or water heater for short periods of time by remote control.

Load Forecast

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

Load Management DSM

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

Load Profile

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

Load Shedding

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

Load Tap Changer (LTC)

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

Low Sulfur Fuel Oil (LSFO)

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

Low Sulfur Industrial Fuel Oil (LSIFO)

A fuel oil that contains up to 7,500 parts per million of sulfur; about 0.75% sulfur content. LSIFO is used by Maui Electric and Hawai'i Electric Light if a fuel with lower sulfur content than MSFO is needed.

Low Voltages

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

M

Maalaea Power Plant (MPP)

The largest power plant on Maui, with 15 diesel units, a combined cycle gas turbine, and a combined/simple cycle gas turbine totaling 208.42 MW (net) of firm capacity.

Maintenance Outage

See Outage on page B-23.

MBtu

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

Medium Sulfur Fuel Oil (MSFO)

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

Megawatt (MW)

A unit of power, capacity, or demand equal to one million watts. The Companies typically express their generating capacities and system demand in Megawatts.

Megawatt-hour (MWh)

A unit of electric energy equal to one million watt-hours. The Companies from time to time express the energy output of their generators or the amount of energy purchased from Independent Power Producers in megawatt-hours.

MMBtu

One million Btu. See also British Thermal Unit on page B-3.

Modern Grid

An umbrella term used to describe transformed grid, including communications, AMI, ADMS, and DA.

Must Run Unit

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

N

N-1 Contingency

A condition that happens when a planned or unplanned outage of a transmission facility occurs while all other transmission facilities are in service. Also known as an N-1 condition.

Nameplate Generation

See Generation (Electricity) on page B-14.

Net Capacity

See Capacity, Generating on page B-4.

Net Energy Metering (NEM)

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

Net Generation

See Generation (Electricity) on page B-14.

Nitrogen Oxide (NO_x)

A pollutant and strong greenhouse gas emitted by combusting fuels.

Nominal Value (Nominal Dollars)

While a complex topic, at its most basic, value is based on a measure of money over a period of time. Generally expressed in terms of US dollars, nominal value represents a money cost in a given year, usually the current year. As such, nominal dollars can also be referred to as current dollars.

Non-Export Model

A tariff structure governing the interconnection of non-export DG systems.

Non-transmission alternatives

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

North American Electric Reliability Corporation (NERC)

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

O

Off-Peak Energy

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

On-Peak Energy

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

Operation and Maintenance (O&M) Expense

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

Operating Reliability

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Operating Reserves

There are two types of operating reserves that enable an immediate or near immediate response to an increase in demand. (See also Reserve on page B-28.)

Spinning Reserve Service: Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Supplemental Reserve Service: Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Outage

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

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

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

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

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

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

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

P

Partial Outage

See Outage on page B-23.

Peak Demand

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

Peaker

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

Peaking Capacity

See Capacity, Generating on page B-4.

Phase imbalance

A condition in which there is a voltage imbalance across two or more phases of a multi-phase system.

Photovoltaic (PV)

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

Planned Outage

See Outage on page B-23.

Planning Reserve

See Reserve on page B-28.

Plug-in Electric Vehicle (PEV)

An umbrella term encompassing all electric or hybrid electric vehicles that can be recharged through an external electricity source.

Power

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

Power Factor

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

Power Generating Technology

The myriad ways in which electric power is produced, including both commercially available technologies and emerging technologies, as well as hypothetical technologies.

Power Purchase Agreement (PPA)

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

Present Value

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

Primary Lines

The main high-voltage lines of the transmission and distribution network.

Proactive Approach

A forward-looking process governing the forecasting of penetration of DER on distribution circuits, analysis of operational constraints, and pre-emptive mitigation of these constraints.

Public Benefits Fee Administrator (PBFA)

A third-party agent that handles energy efficiency rebates and incentives for the Hawaiian Electric Companies.

Pumped Storage Hydro

See Storage on page B-31.

Q

Qualitative

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

Quantitative

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

R

Ramping Capability

A measure of the speed at which a generating unit can increase or decrease output.

Rate Base

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

Reactive Power

The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment.

Real Dollars

While a complex topic, at its most basic, value is a measure of money over a period of time. Generally expressed in terms of units of US dollars, real dollars represents the true cost inclusive of inflationary adjustments (such as simple price changes which, of course, are usually price increases). Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars.

Recloser

A circuit breaker with the ability to reclose after a fault-induced circuit break.

Reconductoring

The process of replacing the cable or wiring on a distribution or transmission line.

Regulating Reserves

The capacity required to maintain system frequency through fast balancing.

Reliability

The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, Adequacy of Supply and System Security. See also System Reliability on page B-33.

Renewable Energy Resources

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

Renewable energy resources include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

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

Renewable Portfolio Standard (RPS)

A goal for the percentage of electricity sales in Hawai'i to be derived from renewable energy sources. The RPS is set by state law. Savings from energy efficiency and displacement or offset technologies are part of the RPS until January 2015, when they will instead be counted toward the new EEPS. The current RPS calls for 10% of net electricity sales by December 31, 2010; 15% of net electricity sales by December 31, 2015; 25% of net electricity sales by December 31, 2020; and 40% of net electricity sales by December 31, 2030.

Repowering

A means of permanently increasing the output and/or the efficiency of conventional thermal generating facilities.

Reserve

There are two types of reserves:

> ***Operating Reserve:*** That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. See also Operating Reserves on page B-23.

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

Reserve Margin (Planning)

The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Such capacity may be maintained for the purpose of providing operational flexibility and for preserving system reliability.

Residential Direct Load Control (RDLC)

A demand response program that offers incentives to customers who allow the Hawaiian Electric Companies to install a load control switch on residential electric water heater, so that the load can be curtailed remotely by the utility during times of system need.

Resiliency

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

Retail Rate

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

Reverse Flow

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

Rule 14H

The Hawaiian Electric Company rules governing service connections and facilities on a customer's premises.

Rule 18

The Hawaiian Electric Company rules governing Net Energy Metering.

S

Schedule Q

The tariff structure that governs Hawaiian Electric purchases from qualifying facilities 100kW or less

Scheduled Outage

See Outage on page B-23.

Secondary Lines

Low voltage distribution lines directly serving customers.

Service Charge

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

Service Level Issue

Any issue arising at the point of service provision to customers, including traditional utility service and grounding transformer overloads caused by DG PV.

Service Transformer

A transformer that performs the final voltage step-down from the distribution circuit to levels usable by customers.

Simple-Cycle Combustion Turbine (SCCT)

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

Single-Train Combined Cycle (STCC)

See Combined Cycle on page B-5.

Small Business Direct Load Control (SBDLC)

A demand response programs that allows the electric utility to curtail load without intervention of an operator at the end user's (customer's) premises. For example, the utility may install a load control switch on an electric water heater or air-conditioning unit, so that the load can be controlled remotely by the utility during times of system need.

Smart Grid

A platform connecting grid hardware devices to smart grid applications, including VVO, AMI, Direct Load Control, and Electric Vehicle Charging.

Smart Inverter Working Group (SIWG)

A working group created by the California Public Utilities Commission to propose updates to the technical requirements of inverters.

Spinning Reserve Service

See Operating Reserves on page B-23.

Standard Interconnection Agreement (SIA)

Rules governing interconnection of distributed generation systems.

Standby Charge

A fixed charge intended to recover significant backup generation facilities the utility must maintain to ensure grid reliability in the event of widespread DG outages.

Static VAR Compensator

A device used provide reactive power in order to smooth voltage swings.

Steady-State Conditions

Conditions governing normal grid operations; contrasted with transient conditions.

Steam Turbine (ST)

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

Storage

A system or a device capable of storing electrical energy to serve as an ancillary service resource on the utility system and/or to provide other energy services. Three major types of energy storage are relevant for consideration in Hawaiʻi:

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

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

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

Sulfur Oxide (SO_x)

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

Substation

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

Substation Transformer

Substation-sited transformers used to change voltage levels between transmission lines, or between transmission lines and distribution lines.

Supervisory Control and Data Acquisition (SCADA)

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

Supplemental Reserve Service

See Operating Reserves on page B-23.

Supply-Side Management

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

Switching Station

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

Synchronous Condensers

Devices used to modulate the voltage or power factor of transmission lines. Synchronous condensers typically provide dynamic reactive power support, and are deployed only where dynamic reactive power support needs to be maintained at a particular location.

System

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

System Average Interruption Duration Index (SAIDI)

The average outage duration for each customer served. A reliability indicator.

System Average Interruption Frequency Index (SAIFI)

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

System Reliability

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

System Security

The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

T

Tariff

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

Thermal Loading

The maximum current that a conductor can transfer without overheating.

Time-of-Use (TOU) Rates

The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

Total Resource Cost (TRC)

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

Transformer

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

Transient Condition

An aberrant grid condition that begins with an adverse event and ends with the return to steady-state conditions (stable voltage, connection of all loads).

Transient Over Voltage (TrOV)

A transient issue characterized by a sudden spike in voltage above steady-state conditions on a circuit, or on a subset or component of a circuit.

Transmission and Distribution (T&D)

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

Transmission System

The portion of the electric grid the transports bulk energy from generators to the distribution circuits.

Two-Way Communications

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

U

Ultra Low Sulfur Diesel (ULSD)

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

Under Frequency Load Shedding (UFLS)

A system protection scheme used during transient adverse conditions to balance load and generation.

Under Voltage Load Shedding (UVLS)

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

Under Voltage Violation

Bus voltage less than 0.9 per unit.

United States Department of Defense (DOD)

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

United States Department of Energy (DOE)

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

United States Environmental Protection Agency (EPA)

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

University of Hawai'i Economic Research Organization (UHERO)

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

V

Variable Renewable Energy

A generator whose output varies with the availability of it primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched down, its output cannot be guaranteed 100% of the time when needed. However, the primary energy source may be stored for future use, such as with solar thermal storage, or when converted into electricity via storage technologies. Also referred to as intermittent and as-available renewable energy.

Voltage

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

Voltage Collapse

The sudden and large decrease in the voltage that precipitates shutdown of the electrical system.

Voltage Regulation

A measure of change in the voltage magnitude between the sending and receiving end of a component, such as a transmission or distribution line.

Voltage Regulator Controller

A device used to monitor and regulate voltage levels.

Volt/VAR control

Control over voltage and reactive power levels.

Volt/VAR Optimization (VVO)

The process of monitoring voltages at customer premises through an AMI system, and optimizing them using reactive power control and voltage control capabilities.

W

Watt

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

C. Modeling Analyses Methods

Three teams conducted independent modeling analysis for produce the results presented in the PSIP. The teams included Hawaiian Electric Company generation planning, Black & Veatch, and PA Consulting. Each team employed a different modeling analysis method. In additional, Electric Power Systems employed a grid simulation model to conduct its system security studies.

Each of these four modeling methods are presented.

GRID SIMULATION MODEL FOR SYSTEM SECURITY ANALYSIS

The Transmission Planning Division of Hawaiian Electric Company uses the Siemens PSSE (Version 33) Power-Flow and Transient Stability program for transmission grid modeling and for system security analysis. This program is one of three most commonly used grid simulation programs in United States utilities. The program supports the IEEE (Institute of Electric and Electronic Engineer) generic models for generators and inverters. When available, custom models can preclude generic models.

PSSE is high-performance transmission planning software that has supported the power community with meticulous and comprehensive modeling capabilities for more than 40 years. The probabilistic analyses and advanced dynamics modeling capabilities included in PSSE provide transmission planning and operations engineers a broad range of methodologies for use in the design and operation of reliable networks. PSSE is used for power system transmission analysis in over 115 countries worldwide.

The program has two distinct program models: (1) power flow to represent steady state conditions and (2) stability to represent transients caused by faults and rapid changes in generation. The transient conditions are modeled to about 10 seconds after which most system will stabilize or fail.

After major system disturbances, we use this program to verify the system events as well as to verify the modeling assumptions.

Input to this program includes impedances for all the transmission lines, transformers, and capacitors; detailed information of the electrical characteristics of all generators and inverters (including PV panels and wind turbines); and energy storage devices (such as batteries). The model includes relays for fault clearing and under-frequency load shedding (UFLS).

Electric Power Systems used the PSSE model to conduct its robust and detailed system security studies because the model allows rapid and consistent sharing of data.

HAWAIIAN ELECTRIC: P-MONTH MODELING ANALYSIS METHODS

The Companies used computer models for the PSIP analyses. Production costs of the operating the system is simulated using the P-Month hourly production simulation model. The model is populated with unit data to characterize the resources operating on the system at all hours so that the performance and cost of the system can be evaluated for various future cases. The data from the hourly production simulation model is processed using other internally developed tools to evaluate the results of the simulations.

P-MONTH Hourly Production Simulation Model

Thermal Generation Modeling

The model, P-MONTH, is an hourly production simulation program supplied by the P Plus Corporation (PPC). This model simulates the chronological, hour-by-hour operation of the generation system by dispatching (mathematically allocating) the forecasted hourly load among the generating units in operation. Unit commitment and dispatch levels are based on fuel cost, transmission loss (or "penalty") factors, and transmission system requirements. The load is dispatched by the model such that the overall fuel expense of the system is minimized (that is, "economic dispatch") within the constraints of the system. The model calculates the fuel consumed using the unit dispatch described above, based on the load carried by each unit and the unit's efficiency characteristics. The total fuel consumed is the summation of each unit's hourly fuel consumption.

Variable Generation Modeling

The model calculates the energy produced by renewable resources and other variables using an 8760 hourly profile. This profile is constructed based on historical observed output from in service variable generation or from solar irradiance profiles and measured wind potential for future variable generation. Generation that is produced according to this hourly profile that cannot be accommodated on the system in any one hour will be curtailed per the curtailment order. The curtailment order follows a last in, first out rule whereby the last installed variable renewable resource will be curtailed first, that is, reverse chronological order.

Unit Forced Outage Modeling

The production simulation model can be used by applying one of two techniques: probabilistic or Monte Carlo. Using the probabilistic technique, the model will assume generating units are available to operate (when they are not on overhaul) at some given load that is determined by their normal top load rating and forced outage rate. By this methodology, the units will nearly always be available at a derated capacity that has been reduced to account for the forced outage rate.

PMONTH has a Monte Carlo Simulation option in which random draws are used to create multiple scenarios (iterations) to model the effect of random forced outages of generating units. Each scenario is simulated individually; the averages of the results for all the scenarios represent the expected system results. This Option provides the most accurate simulation of the power system operations if sufficient number of scenarios are used. However, the computer run time can be long if many scenarios are run. The number of scenarios needed to establish a certain level of confidence in the results depends on the objectives of the user and the size of the system. Normally, the system production cost will converge sufficiently between 20 and 30 iterations.

Using the Monte Carlo, or deterministic, technique, forced outages for generating units are treated as random, discrete outages in one week increments. The model will randomly take a generating unit out of service (during periods when it is available) up to a total forced outage time of 5%. By this methodology, the unit can operate at normal top load for 95% of the time when it is not on overhaul but will not be able to operate (that is, will have a zero output) for 5% of the time when it is not on overhaul. For the PSIP, the modeling will use the Monte Carlo methodology to capture the forced outages of all thermal units.

Demand Response Modeling

Demand response programs were modeled to provide several benefits including capacity deferral and regulating reserve. Programs that provide capacity were included in the capacity planning criteria analysis assessment. Programs that provide regulating reserve ancillary services were included in the modeling.

Energy Storage Modeling

The benefits of energy storage for system contingencies are captured in the system security modeling. Regulating reserves were provided by a combination of energy storage and thermal generation. Load shifting was modeled as a scheduled energy storage resource. The roundtrip efficiency was accounted for in the charging of this resource. The charging schedule was optimized to coincide with the hours in which curtailment occurred or the profile of PV energy during the day to minimize day time curtailment. The discharging schedule coincided with the evening peak.

System Security Requirements

The system security requirements were met by including the regulating and contingency reserve capabilities of demand response, energy storage, and thermal generation in the modeling. The system security requirements depend on the levels of PV and wind on the system. The regulating reserve requirements were changed hourly in the model to reflect the dynamic changes in levels of PV and wind throughout the day. Curtailed energy from controllable PV and future wind resources contributed to meeting the regulating reserve requirement. The contingency reserve requirements were changed annually to reflect the largest unit contingency on the system.

Sub-Hourly Model

The P-Month model is an hourly chronological model. Sub-hourly modeling cannot be done using this model. The Companies developed a limited sub-hourly model to assess the any value that the hourly model was not able to capture compared to the modeling sub-hourly when batteries, and other resources that operate like batteries, are on the system.

Key Model Inputs

In addition to the system changes described in the Base Plan, there are several key assumptions that are required for modeling:

1. Energy and hourly load to be served by firm and non-firm generating units
2. Load carrying capability of each firm generating unit
3. Efficiency characteristics of each firm generating unit
4. Variable O&M costs
5. Operating constraints such as must-run units or minimum energy purchases from purchased power producers
6. Overhaul maintenance schedules for the generating units
7. Estimated forced outage rates and maintenance outage rates
8. Regulating reserve requirements
9. Demand response and energy storage resources
10. Fuel price forecasts for fuels used by generating units

Methodology for Post-Processing of Production Simulation Results

Key Outputs

Some of the key outputs from the model are as follows:

1. Generation produced by each firm generation units
2. Generation accepted into the system by non-firm generating units
3. Excess energy not accepted into the system (curtailed energy)
4. Fuel consumption and fuel costs
5. Variable and fixed O&M costs
6. Start-up costs

Post-Processing

The outputs from the model are post-processed using Excel to incorporate the following:

1. Capital costs for new generating units, renewable and energy storage resources, allocated based on capital expenditure profiles
2. Capital costs for utility projects such as fuel conversions or the retirement of existing utility generating units
3. Payments to Independent Power Producers (IPP) for purchased power, including Feed in Tariff projects
4. Fixed O&M for future energy storage resources

All costs are post-processed into annual and total dollars to be used in the Financial Model. All annual, total, and present value (2015$) revenue requirements are also post-processed for use in evaluating the different plans but are not meant to be the "all-in costs" that the Financial Model will be doing. Revenue requirements are characterized as utility and IPP. Utility revenue requirements are categorized into fuel, fixed O&M, variable O&M, and capital. IPP revenue requirements are categorized into capacity and energy payments. Using the revenue requirements from post-processing, plans can be analyzed according to several key metrics.

Key Metrics

The key metrics analyzed through post processing of the model data are as follows:

1. Differential accumulated present value of annual revenue requirements
2. Differential rate impact
3. Monthly bill impact
4. Total system curtailment
5. Renewable Portfolio Standards (RPS)
6. Gas consumption
7. Utility CO_2 emissions
8. Annual Generation Mix
9. Daily Generation Mix by Hour

Lana'i & Moloka'i Modeling

The model used in the analysis for Lana'i and Moloka'i is an Excel based model focusing on meeting the total sales (energy) forecasted for each year. In this way the amount of energy produced from each resource was assumed to be taken regardless of any profiles. This simplified model shows results that are directionally correct.

The model calculations are broken up into three pieces: existing power purchase agreements, future renewable resources, and utility generation. First, it is assumed that the utility generation will provide a minimum amount of generation for system reliability. Second, the existing power purchase agreements fill in additional energy based on historical purchases. Lastly, future resources can be added to get as close to the total sales as possible. If the total energy provided by the three pieces is less than forecasted sales for a particular year, the utility generation will increase to make up the difference. If the total energy is greater than forecasted sales then the excess is curtailed from newly added resources.

The model will track all costs associated with fuel expense, O&M, capital, and power purchased payments to give annual revenue requirements and total net present value (NPV) consistent with the analysis for the other islands. Similarly, the model will also calculate the Renewable Portfolio Standards (RPS) percent for each year of the plan.

The utility generation component allows for different fuels to be assigned to the units as well as splitting the fuel types as necessary. Fuel usage and associated costs are calculated for each year.

Future renewable resources are identified by the year of installation as well as ownership (for example, utility or IPP). Resource ownership determines the capital expenditures patterns. Either a levelized profile or a declining profile to match company revenue requirements is used in the analysis. Costs for O&M and applicable fuel costs for each year are calculated for the new resources.

PA CONSULTING: PRODUCTION COST MODELING

PA Consulting Group (PA) performed hourly and sub-hourly production cost modeling to support the Hawaiian Electric Companies' development of the PSIPs. The production cost modeling was conducted using the EPIS AURORAxmp software. AURORA is an hourly chronological dispatch model used to model electricity markets. The model has broad capabilities. The primary forecasting capabilities that we used in the model are least cost dispatch and long-term capacity expansion modeling.

The capacity expansion model is an optimization model that determines the most cost effective long-term generation expansion and retirement schedules, based upon assumptions regarding capital costs, operating costs, and operational constraints, as well as system constraints such as reserve margins and spin requirements. The most cost effective plan is based upon the solution with the lowest net present value.

The chronological dispatch model determines the least-cost solution for dispatching resources, including demand side resources, to meet load and reserve margin requirements. The dispatch solution honors individual generator constraints and factors in marginal dispatch costs, including fuel and O&M. Each resource is modeled individually, taking into account the unit-specific cost and operating characteristics. Units are dispatched in the simulation in the order of economic merit (according to dispatch cost) until adequate generation is brought on line to meet the load. The model factors in out-of-merit dispatch due to must-run and must-take requirements. The model also curtails resources if the constrained generation exceeds demand.

The sub-hourly modeling was structured to address the Commission's interest in utilizing sub-hourly modeling to more fully investigate issues raised in the April 28th D&Os. These issues include evaluation of the value of DR and DG in the context of the Company's vision for the future of the utility, and consideration of resources required to support the integration of more intermittent renewable generation resources, and to reduce curtailments where it is economic to do so.

Specifically, PA used the sub-hourly modeling to identify any periods with unserved energy or periods with significant potential for renewable energy curtailment. We evaluated whether changing the resource mix can cost effectively address these issues. This assessment was conducted using iterative analyses to identify whether changing the available resource mix will reduce curtailment or dispatch costs.

AURORA was used to both evaluate a least-cost capacity expansion and retirement plan, and also to model scenarios of alternative resource plans in order to identify the incremental costs associated with alternative policies.

Key Inputs

PA worked with Hawaiian Electric Resource Planning and Black & Veatch to develop a common set of assumptions for the modeling initiative. These assumptions include:

- Resource characteristics (such as capacity, heat rates, ramp rates, minimum-up times, and minimum-down times)
- Characteristics of demand response programs
- Fuel costs
- Types of fuel that each fossil generator will use
- Identification of timing and generators that would be converted to burn LNG
- Fixed and variable operating costs
- Capital costs necessary to extend the life of existing generation
- Costs for new generation technologies (capital and operating)
- Availability of new generation resources (timing and capacities)
- System load forecasts
- Production profiles for variable energy resources.

Hourly Production Cost Modeling

Generation and demand side resources are dispatched to serve the system load. The base case simulations reflect the current configuration in which each island is a stand-alone system.[1] Units with low operating costs relative to other facilities are dispatched often; units with high costs are dispatched less frequently. The hourly dispatch logic is based upon short-run marginal generation costs, which include: fuel costs, variable operating costs, start-up costs, and emission costs. In contrast, the long-term retirement and expansion plan considers all costs rather than just marginal costs. The additional costs in the long run optimization include fixed O&M costs and capital costs.

The hour-by-hour interaction of supply and demand determines how frequently plants are dispatched within a market. The model incorporates logic for a variety of constraints that are incorporated into the least-cost dispatch logic. These constraints include: must-run requirements, minimum load requirements, ramp times, minimum uptimes, and minimum downtimes. The model also includes planned maintenance schedules and forced outage rates. The determination of the least-cost dispatch, subject to constraints, is based upon the model, assuming perfect information about future hourly loads.

PA used an iterative process to develop the preferred PSIP for each island. Our first step was to represent the existing systems within the model and develop simulations for the

[1] A case was run with a 200 MW DC transmission cable connecting the islands of O'ahu and Maui.

first two years. We used these simulations to calibrate the models to reasonably represent how the current power systems dispatch and to capture the current generation operating costs, fuel costs, and purchase power agreements. We then used the optimization model to develop a least cost base case that factored in constraints related to committed generation retirements, assumptions about future levels of distributed generation, and availability of new generation resources. In the third stage of our analysis we tested alternative scenarios to examine the incremental costs of alternative power supply plans. The analysis in the third stage was based upon modeling specific scenarios over the 2015–2030 time horizon and did not use the long-term resource optimization feature.

Sub-Hourly Production Cost Modeling

The purpose of the sub-hourly modeling was to gain insights regarding ramp constraints, identify potential issues with large amounts of variable supply resources, and identify the potential value of fast response resources, including demand response resources. We use sub-hourly modeling to identify any periods with unserved energy or high frequency, and amounts of renewable energy curtailment. We then assess whether changing the resource mix can cost effectively address these issues.

The sub-hourly modeling was conducted with the previously described production cost model. In order to develop the sub-hourly analysis, it was necessary to convert all the hourly generation and variable supply resource profiles into five-minute profiles. We did not change any assumptions about fuel costs or generator constraints. A brief description of the process for developing the five-minute profiles follows.

We started with available one-minute historic net load profiles, wind production profiles, and solar production profiles. We developed a one-minute gross load profile from the one-minute profiles into five-minute profiles using averages of the five-minute periods. In instances where we did not have sub-hourly data, such as for hydro generation, we assumed that the generation was constant over the one hour period.

PA modeled four days per month at the five-minute level, rather than every day, due to the large amounts of data associated with five-minute modeling. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day.

An overview of PA's sub-hourly modeling methodology follows. This modeling will be conducted at the five-minute intervals.

1. Development of Sub-Hour Modeling Assumptions and Data Inputs

We based inputs to the sub-hourly model on the assumptions agreed upon for the hourly model (fuel costs, generator characteristics, and load forecast) and on one-minute data.

The one-minute data include historic net load profiles, wind production profiles, and solar production profiles. In addition, PA incorporated input from parallel tasks related to development of DG and DR unit characteristics and cost options, as well as how that analysis should be integrated into the sub-hourly chronological dispatch modeling. PA closely coordinated these efforts with the company to ensure that the modeling assumptions and scenarios modeled are consistent with the Company's strategic vision.

2. Translation of Hourly Model Assumptions/Inputs to Five-minute Data

The vast majority of assumptions and inputs used for hourly modeling were used directly in the 5-minute modeling. These include fuel costs, resource capacities and efficiencies, and resource variable operating costs, as well as system operating reserve requirements. In some cases, dynamic information such as resource ramp rates and other time dependent assumptions were adjusted to correspond to the five-minute modeling interval, so that the inputs were correctly incorporated in to the model's economic dispatch algorithms.

3. Development of Five-minute Profiles for Modeling Inputs

We converted renewable generation production profiles from one-minute to five-minute data, and converted the hourly load forecasts to five-minute profiles using the historic one minute load profiles. The conversion ensured consistency between the hourly, one-minute, and five-minute data sets.

Renewable Generation Profiles. Five-minute profiles for wind and solar were constructed from available one-minute data. PA analyzed the one-minute data to develop representative five-minute shapes for typical days in each month. The representative five-minute shapes were not limited to simple averages of one-minute renewable output levels across days, but were structured to represent the extent of variation that exists at the one minute level. There was only one one-minute wind and solar profile per island so all solar and wind resources on each island used the common wind / solar profile. The capacity of the individual units were adjusted so that over a year the total production matched each unit's characteristics.

Load Shape and Distributed Generation Profiles. The derivation of the five-minute load shape profiles required a different analysis, since existing load data reflect behind-the-meter generation. Given time limitations, PA utilize an Excel-based model to construct five-minute load shapes for future years. Future load shapes were based on the current five-minute system load shape and the hourly load forecasts. PA used the five-minute PV production shape and penetration estimates for behind-the-meter solar to allocate the hourly loads into five-minute blocks representing gross system loads (without behind-the-meter generation) and net system loads for future years.

4. Sub-Hourly Model Development and Calibration

PA modeled four days per month at the five-minute level. We did not model all days due to the large amount of data at the five-minute level, and array limitations in the AURORAxmp software. The four representative days included a mid-week weekday (Monday–Thursday), a Friday, and each week-end day. Depending on model run-times and post processing efforts, PA either weighted the midweek day to represent four days, or performed additional simulations to capture a typical week per month to facilitate developing aggregate annual results.

PA developed and validated sub-hourly generation dispatch models for the Maui, Oʻahu, and Hawaiʻi Island systems. Since AURORAxmp is currently configured for hourly modeling, PA had to adjust input parameters to facilitate five-minute modeling. PA adjusted input parameters so that each standard Aurora model hour is interpreted as a five-minute period. Hence, each representative day consisted of 288 standard Aurora model hours. Each representative day was modeled independently, and the standard Aurora model hourly output was aggregated through post processing to produce results for the day.

PA conducted a calibration exercise to verify that the model results made sense in the context of the sub-hourly modeling. We also verified that the sub-hourly modeling results are logical and reasonable, based upon PA's expertise and based upon consultation with generation planning and generation operations staff expertise within the Company. After the results were validated for each system, PA executed simulations of the representative, P5, and P95 cases for each system. Annual system costs and performance metrics were calculated for each set of system conditions.

The simulations provided insights into the resource requirements necessary to meet load requirements with a mix of intermittent and non-intermittent resources. PA used the hourly simulations to capture the full capital and fixed operating costs for the purposes of estimating the total generation system operating costs at the annual level.

BLACK & VEATCH: ADAPTIVE PLANNING MODEL

Black & Veatch is applying its Adaptive Planning Framework to support the PSIP. Adaptive planning provides a framework for modeling complex systems, exploring options (and impacts of constraints), and comparing such options across varying metrics. Key metrics or outcomes would be costs, annual capital commitment required, degree of renewable penetration (capacity, energy served), and system reliability.

The Adaptive Planning Framework manages the overall calculation and cost accounting process. PSIP-specific requirements will be directly addressed by configuring the model:

- Dispatch methodology defined by collective Hawaiian Electric team, based on legal mandates, operational protocols, and defined reserve margins.
- Dispatch models and algorithms tailored to address system constraints (safety, security), loading or ramping criteria defined by Hawaiian Electric by asset class, battery charge, and discharge protocols by size and class of battery, among others.
- Repair times by asset class for projected failures and scheduled outages.
- Full cost accounting of all power supply elements by asset class, nature of cost, and other factors.

Different solution approaches can be applied in adaptive planning. As configured for this plan, the dispatch and economic models do not optimize capacity additions directly, as we believe that there are number of factors and complexities that dictate technology strategies and paths that need to be "engineered". We have, rather, focused on leveraging the model to evaluate alternate technology and capacity plans, including the adequacy of these plans to meet reserve margin or cause curtailment.

For this particular problem, given the complexity, the number of constraints, and the need to consider system security and reliability thresholds in each period, we have elected to apply the following:

- In concert with Hawaiian Electric and PA Consulting, define the general characteristics of base "path" based on central strategy and glide-path analysis. This will define some key initial assumptions regarding technology choice, timing, and retirements.
- Based on this analysis, the B&V team will then define alternative technology mixes or paths that need to be investigated; the focus would be to improve economics, flexibility, grid resiliency, or other factors based on our assessment of year-to-year unit commitment and dispatch data; this effort will also directly explore roles and penetration of battery assets over time.

- The team will generate sensitivities for each path (base and alternative) to stress test results; key variables that can be considered would be aggregate demand by system, the amount of spinning reserves over time (by year coincident with asset mix and by hour to address night-time or off-peak versus peak requirements), timing of capital investments, technology flips (battery versus pumped storage, battery versus thermal for contingency, etc.), timing of retirements, etc.

We believe that this approach maximizes our ability to provide visibility into results and key assumptions, as needed to define optimal PSIP path. It will also allow for direct comparison of decisions and timing that will be critical for Hawaiian Electric in subsequent steps to refine financial engineering of overall rates. Given the short time frame of this study, we do not plan on directly integrating a regulatory or rate model with AP framework, but would work with Hawaiian Electric to apply results of our work within existing spreadsheet models to enable analysis of investment requirements and the nature of investments over the evaluation period.

Economic results will be driven, in part, by market forecasts for fuel (oil, LNG, etc.). The Black & Veatch framework provides robust scenario analysis that will be applied in this case to evaluate:

- Mix and timing of renewable and energy storage assets
- Timing of retirements
- Timing and nature of new generation additions
- Timing and nature of participation from IPPs
- System characteristics
- Reliability risk based on level of investment and intensity of asset type
- Alternate views of costs including market price of fuel, the cost of implementing technology, etc., as needed to address increasingly higher degree of renewable penetration over time.

Economics can be applied in different forms within the model. We can consider:

- Direct capital investment in year of investments driven by project S-curves.
- Levelized costs based on spread of CAPEX and other related costs into an equivalent annual annuity.
- RRF schedule. Capital can be spread and factors can be assigned based on RRF input schedules.
- Third-party contract (IPP, DR, etc.) where the energy or service can be contracted on $/MWh, $/MW, or combination.

Model outputs will be populated within spreadsheets and data viewers to enable direct analysis and comparison (between cases) of:

- Period values by asset; periods can be either 1-hour or 5-minute for PSIP. We will also consider a smaller segment of 1-minute data to test impacts on wind and solar dispatch and spin. Detailed results would include dispatch MW, costs (capital, VOM, FOM), contribution to renewable, and role (contingency, regulation, energy, etc.)
- Aggregated results by asset; basically the same output as available for the period would be available for the asset by year and overall.
- Typical "daily" or 24-hour view; this view would analyze data for each asset by hour in day resulting from dispatch by asset by year. This will allow us to validate the overall dispatch approach, as well as better characterize roles of units. Values calculated would include average, min, max, and standard deviation. This will provide insights into rationale for IPP energy supply schedules for assets that are not anticipated to be owned by Hawaiian Electric.

Time Slice Model within Adaptive Planning Framework.

At the heart of the Adaptive Planning framework is a direct solution mathematical framework that enables direct analysis and "integration" of asset performance and aggregate match of resources to demand (as depicted in the figure below) contribution by asset, aggregate reliability, and costs.

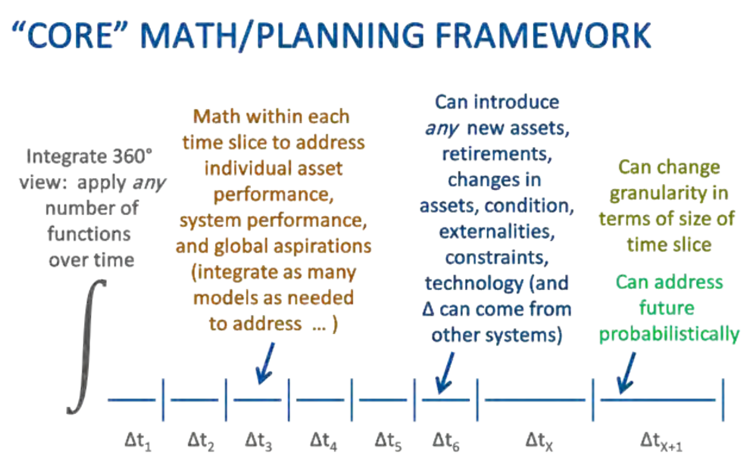

Figure C-1. Black & Veatch Mathematical Modeling Framework

Within the framework, each time slice affords the opportunity for us to:

- Introduce new assets, retire assets, change characteristics (simulate planned outages, etc.).
- Commit assets based on availability, renewable and non-renewable, and economics.

- Incorporate assumptions for wind and solar variability for that particular time slice based on perturbations of the historical wind and solar patterns.
- Incorporate rules for utilizing DG as must-take resource versus curtailable resource.
- Dispatch assets based on protocol and security, and economics including use of DR and energy storage to address ramping or smoothing, forced outages of committed assets, etc.
- Identify boundary conditions (from time slice to time slice) that serve as the basis for evaluating the next time slice; there are a number of instances where actions (such as a start of a 10-minute or 30-minute reserve resource within a particular time slice) will require forward commitment across time slices.

The time slice model works in conjunction with the economic dispatch model to evaluate the situation in the current period and translate this information to subsequent affected time slices. Each time slice considers (takes as input) for each power source:

- Status (available, scheduled outage, forced outage, retired, etc.)
- Operating efficiency
- Fuel characteristics (if applicable)
- Consumable unit costs
- Revenue requirements for capital expenditure

Each time slice also considers demand, adjusted for DR load shaping programs and, as applicable, DG PV. With this information, the time slice model determines:

- Status applicable to next time slice
- Consumable requirements
- Operating costs

The information generated is available at the time-slice or less granular resolution, for example, hourly, monthly, or annually. In addition, the asset hierarchy allows data to be viewed for each power source or aggregated across sources. Capital costs and other outputs associated with those investments would be tabulated by calendar year or other time domain, as required.

Generation Dispatch Methodology

The dispatch model will be used to set the electrical generation outputs to satisfy the electrical demand at the lowest cost while also satisfying system constraints (constrained optimization). These constraints will include system stability (must-run units), minimum downtime and uptime constraints, spinning and non-spinning reserve margin requirements, and non-dispatchable renewable generation. The model will use the following data:

- Variable costs and start-up costs for electrical generation assets
- Ramp rates, minimum downtime, and minimum uptime for electrical generation assets
- Historical reliability and maintainability (MTBF, MTTR) data for all generation assets
- Solar and wind penetration forecast (by time step resolution)
- Solar and wind forecasts (by time step resolution)
- Demand forecasts (by time step resolution)
- System losses

Demand response will be factored into this model via two forms: 1) change in overall "demand" curve as influenced by time-of-day pricing and 2) modeling of specific DR programs.

Energy storage is applied as a resource to supply capacity, regulation, contingency, and other ancillary services associated with frequency response and security. Energy storage added to supply capacity, regulation, or contingency will be modeled via the dispatch model; energy storage added to frequency response will be considered as a cost component of the overall system.

Sub-Hourly Model

Traditional hourly modeling does not expose the operational transients that must be managed during real-time operation of the electric grid. Hence, traditional hourly modeling also does not expose potential value (economic and risk mitigation value, for example) that one set of assets may have over another set of assets, as all transients are softened. Sub-hourly modeling will expose some of this value to support the optimum resource selection that does not violate policy considerations (risk tolerance, renewable goals, budget constraints, fuel diversity, etc.)

Similar to an hourly modeling approach, the sub-hourly model will calculate both commitment (what units are generating power) and dispatch (MW contribution of each asset to the target load) but now at a sub-hourly time step. Maximum daily rate of change will be greater and ramp rate constraints will be hit more often, thereby potentially changing the economic outcome of the simulation as compared to the hourly model. The hourly model assumes dispatch and commitment set points that do not violate any constraints when the time step is one hour, but when the truer transient nature is exposed at the sub-hourly time step, some otherwise masked constraints will likely become controlling.

The sub-hourly model (5 minute time step) will perform a constrained optimization for both asset commitment and asset dispatch against a sub-hourly desired load that utilizes both near term (next few time steps ahead) and intermediate term (out to the largest minimum down time of committed assets) load forecasts. The assets considered include generation (dispatchable and non-dispatchable), demand response, and energy storage. Each asset will have two primary states: available or unavailable. Each unavailable state may have sub-states—for example, scheduled versus unscheduled outage. Each asset will also have a series of constraints or attributes:

- Maximum output (or curtailment)
- Minimum output (or curtailment)
- Ramp up constraint
- Ramp down constraint
- Minimum run time
- Minimum down time
- Maximum run time curve as a function of operating state (energy storage, demand response, emission limits, fuel availability, etc.)
- Time between failures
- Time to restore
- Planned outages
- Startup cost
- Variable cost curve as a function of MW (input/output curve, heat rate curve, O&M, fuel forecast)
- Fixed costs (for annual cost calculations)

There are also system constraints that must be met. These include:

- Spinning reserve requirements (incorporating energy storage and demand response options)
- Grid stability requirements, including must-run units (constraints will be rules-based, as power flow modeling is not envisioned as feasible within the project time constraints)
- Policy constraints (power quality, reliability targets, risk tolerance)

The sub-hourly model will change the state of each asset to optimize the economics within the bounds of the model constraints. Accounting routines will keep track of asset performance ($, MWh, number of starts) and system performance (unserved load, curtailed generation, $, MWh). We envision sensitivities where selected constraints are relaxed and where the load forecast is modified. This will help test the robustness of the plan.

The modeling approach defined above is ideally suited to evaluating, comparing, and contrasting differing strategies regarding the mix of fossil generation, utility renewables versus energy storage, distributed generation versus energy storage, and demand response options. Based on the supply options provided, the model will determine the low-cost means for meeting the required load and base constraints. These constraints can be modified to evaluate other policy considerations (such as greater renewable penetration) that may move the solution away from optimal.

D. System Security Standards

The Hawaiian Electric Company contracted with Electric Power Systems and its two senior project engineers, David A Meyer and David W Burlingame, to conduct a system security and stability study and analysis of the Hawaiian Electric power grid.

Herewith is a discussion of the study and its resultant effects for system security on the Hawaiian Electric power grid.

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INTRODUCTION

EPS completed a study to determine the security constraints required to maintain system reliability in accordance with the draft Transmission Planning criteria TPL-001 and generation Planning criteria BAL-502. Due to the proliferation of distributed PV and its existing characteristics, the system is not currently in compliance with the planning standards. This study analyzed the future changes in generation resources to determine the security constraints required using the existing system topology required to meet the reliability standards. The study's scope is to identify what resources or mitigation measures can be undertaken to maximize the use of renewables and meet the transmission and generation planning criteria.

The initial year of the study is 2015 and proceeds through a series of forecasted load and resources changes through the year 2030. In the years 2015–16 a large amount of distributed PV growth is forecast and in year 2016 there is 283 MW of station class PV expected to be online. Years 2016–2030 forecast less growth in distributed PV but major additions and retirements to the Hawaiian Electric generation fleet and the installation of energy storage expected in 2017.

The years 2015–16 are expected to require mitigating efforts such as unit constraints, curtailment and relaxation of some reliability criteria during certain conditions due to the lack of ability to bring additional energy resources online.

This study outlines the types of mitigation and operating constraints for the years 2015–16 and the resource additions required to meet the security constraints for the system in the years 2017–2030.

It is important to note that this is a planning study and not an operating study. As such, the boundary conditions which the system can be operated will be identified, even though actual operations may not utilize the dispatch or unit commitment conditions identified as the boundary conditions. The boundary conditions were identified by configuring the generation dispatches to stress the system to determine the stability and contingency reserve requirements for the system.

METHODOLOGY

The reduction in system inertia and system response due to displacement of conventional generation units by variable energy will result in a less robust power system. This can potentially increase the amount of stages of the Under Frequency Load Shed (UFLS) system that will activate for unit trips and result in lower critical clearing times for all transmission and subtransmission faults.

System Improvement Assumptions

This section lists the system improvements assumed for the different study years.

2015–2016 Cases

The distributed PV installed prior to 2015 is assumed to be retrofitted to provide ride-through characteristics outlined in the proposed Rule 14h changes. No other system improvements in generation or transmission resources are anticipated.

2017+ Cases

The analysis incorporates a 60 MW Battery Energy Storage System (BESS) assumed to be installed in 2017. The Energy Storage System (ESS) is assumed to have both droop response and auto-schedule response capabilities for control action.

Initial analysis determined that voltage support would be required for the Hawaiian Electric system in order to maintain voltage due to the addition of renewable energy sources. The analysis indicated an initial size of ± 80 MVAR SVC would be adequate to resolve voltage problems on the Hawaiian Electric transmission system.

The critical fault clearing times on the Hawaiian Electric system are below 12 cycles. It is assumed that dual primary, communications assisted relaying is installed on all Hawaiian Electric 138 kV and 46 kV circuits.

The extreme variation in feeder loading during daytime and nighttime conditions require and adaptive relaying scheme for the under frequency load shedding system. This system is assumed to be in service in 2017. Due to the requirements of the under frequency loadshed scheme, SCADA control of all distribution circuits will be required for the new system. It is assumed that SCADA control will be establish to all substations by 2017.

Control of all station class PV is assumed in 2017. Control would allow station PV to be curtailed and used for regulation of other variable resources. Control of all DG PV is assumed in 2017. Control of DG would allow the curtailed PV to provide 10-minute reserves to replace regulation reserves used to counter ramping of the variable generation.

Station class PV is assumed to have both droop response and auto-scheduling response to allow its use as contingency reserves.

PV Assumptions

The amount of PV that would utilize legacy trip settings was analyzed at 40 and 60 MW of the total DG for the 2015–2016 cases. This dual analysis was completed to help quantify the impact of converting some of the existing legacy PV to extended ride through settings.

It was assumed that only 40 MW of the total PV installed would utilize legacy trip settings for voltage and frequency for the 2017+ cases. The remaining PV was assumed to have extended ride through characteristics providing the ability for the PV to remain online during system contingencies. The settings used for the legacy and extended PV capability are shown below in Table D-1.

PV Type	Protection Type		Settings 1		Settings 2	
			Set Point (Hz or	Time (sec)	Set Point (Hz or	Time (sec)
Legacy	Voltage	Over	1.10	0.99	1.2	0.157
		Under	0.88	1.99	0.5	0.157
	Frequency	Over	60.5	0.157	-	-
		Under	59.3	0.157	-	-
Extended	Voltage	Over	1.10	0.99	1.2	0.157
		Under	0.88	1.99	0.5	0.49
	Frequency	Over	63	19.99	-	-
		Under	57	19.99	-	-

Table D-1. PV Settings

It is important to note that the legacy PV has an under frequency trip setting of 59.3 Hz and a relay time of 0.157 seconds. Based on these settings, an under frequency event is likely to result in tripping of the legacy PV, further depressing system frequency following its tripping. The legacy PV trips on over frequency at 60.5 Hz also in 0.157 seconds. The loss of legacy PV following a transmission fault will decrease system security. The extended PV settings have an under frequency set point of 57 Hz and a relay time of 20 seconds, resulting in minimal PV tripping during under frequency events.

Criteria

The criteria for the system security studies are based on Hawaiian Electric's adopted planning document TPL-001. The planning document outlines the transmission and generation contingencies and the acceptable performance of the system.

The generation planning criteria BAL-502 also contains required characteristics of future energy resources that were used in the system studies.

The overriding criteria used for the analysis was that the system should not activate more than the Stage 1 of the UFLS system during single unit outages or a loss of a wind generation facility or PV source. Stage 1 currently results in the loss of customers that is acceptable to the planning criteria in TPL-001. The settings used for the existing UFLS system are shown below in Table D-2.

UFLS Stage	Set Point (Hz)	Relay Time (Sec)	Breaker Time (sec)
Stage 1	58.9	0.033	0.083
Stage 2	58.7	0.033	0.083
Stage 3	58.4	0.033	0.083
Stage 4	58.1	0.033	0.083
Stage 5	57.8	0.033	0.083
Kicker 1	59	5.030	0.083
Kicker 2	59	10.033	0.083

Table D-2. UFLS Settings

During analysis, if the simulation results in a frequency response below 58.7 Hz, outage was reduced and or changes to the UFLS settings were completed to try and meet the criteria. These changes to the UFLS settings include transfer tripping stages 1 and/or stages 2 in order to try and keep the frequency from dropping and tripping any additional stages.

Contingency Reserves Analysis

The replacement of traditional generation with variable generation will require additional contingency reserves for the 2017+ cases. Contingency reserves in the form of additional ESS (or another type of very fast-acting frequency-responsive resource that has the same capabilities as fast energy storage, such as utilizing auto-scheduling of curtailed station class PV) were added to the system provide system stability and meet the performance requirements of TPL-001. The use of auto-scheduling of the curtailed PV and of any ESS would occur 6 cycles after a unit outage.

During analysis, if the simulation results in a frequency response below 58.7 Hz, the contingency reserves (curtailed PV or ESS) were increased in 20 MW increments until the frequency stayed above limits during the simulation.

Contingencies

Contingencies including major 138 kV lines with 7 cycle clearing times and selected transmission lines with zone 2 clearing (5 cycle near clearing and 24 cycle far clearing times, only for 2015 cases)) were used to determine system stability. The outage of the largest thermal unit (typically AES at 200 MW and 100 MW) or wind generation facility was used to identify the ability to meet the standards set forth in TPL-001. A list of contingencies used for the study is shown below in Table D-3.

Dist #	From Bus		To Bus		Branch ID	Clearing Time (Cycles)	
	#	Name	#	Name		Near	Far
d0	100	ARCHER	130	IWILEI	"1"	7	7
d1	100	ARCHER	180	SCHOOL	"1"	7	7
d2	100	ARCHER	240	KEWALO	"1"	7	7
d3	110	CEIP	141	KAHE CD	"1"	7	7
d4	110	CEIP	330	AES	"1"	7	7
d5	110	CEIP	340	EWA NUI	"1"	7	7
d6	120	HALAWA	130	IWILEI	"1"	7	7
d7	120	HALAWA	140	KAHE AB	"1"	7	7
d8	120	HALAWA	150	KOOLAU	"1"	7	7
d9	120	HALAWA	160	MAKALAPA	"1"	7	7
d10	120	HALAWA	180	SCHOOL	"1"	7	7
d11	130	IWILEI	180	SCHOOL	"1"	7	7
d12	130	IWILEI	220	AIRPORT	"1"	7	7
d13	140	KAHE AB	141	KAHE CD	"1"	7	7
d14	140	KAHE AB	190	WAHIAWA	"1"	7	7
d15	140	KAHE AB	200	WAIAU	"1"	7	7
d16	150	KOOLAU	170	PUKELE	"1"	7	7
d17	150	KOOLAU	200	WAIAU	"1"	7	7
d18	160	MAKALAPA	200	WAIAU	"1"	7	7
d19	160	MAKALAPA	220	AIRPORT	"1"	7	7
d20	190	WAHIAWA	200	WAIAU	"1"	7	7
d21	200	WAIAU	340	EWA NUI	"1"	7	7
d22	230	KAMOKU	240	KEWALO	"1"	7	7
d23	310	KALAE	330	AES	"1"	7	7
d24	310	KALAE	340	EWA NUI	"1"	7	7
d25	320	HRRP	330	AES	"1"	7	7
u0	1331	AES	-	-	-	-	
d26	140	KAHE AB	190	WAHIAWA	"1"	5	24
d27	140	KAHE AB	120	HAL1	"1"	5	24
d28	140	KAHE AB	120	HAL2	"2"	5	24
d29	200	WAIAU	190	WAHIAWA	"1"	5	24
d30	200	WAIAU	160	MAKALAPA	"1"	5	24
d31	120	HALAWA	160	MAKALAPA	"1"	5	24
d32	120	HALAWA	180	SCHOOL	"1"	5	24
d33	120	HALAWA	130	IWILEI	"1"	5	24

Table D-3. Contingencies

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Power flow cases were created for the day minimum, day peak, evening peak, and night minimum load times. Specifics for each case are shown below in Table D-4. The DG-PV, station PV, and wind are the variable generation production (in MW). The thermal generation listed is the total MW from thermal generation dispatch. The regulation is the unloaded capacity. The combined load and losses are the demand that is to be served by the generation sources.

Values	2015 Load Cases			
	Day Minimum	Day Peak	Evening Peak	Night Minimum
DG PV	408	408	0	0
Station PV	10	10	0	0
Wind	99	99	99	99
Load	752	1151	1222	554
Losses	8	15	27	10
Thermal Generation	243	649	1150	465
Regulation	135	135	50	50

Table D-4. 2015 Case Specifics

2015: Generation Dispatches

Generation dispatches were created for each case, increasing AES output from a low value (80–100 MW) to the maximum possible output in 20 MW increments. Details of the generation dispatches for the daytime minimum cases are shown in Table D-5.

Unit	2015 Values		2015				
	Pmax	Pmin	Day Min				
Kahe 1	86	24					
Kahe 2	86	24					
Kahe 3	90	24	28				
Kahe 4	89	24	28	28	32	24	24
Kahe 5	142	65	72	80	90	80	65
Kahe 6	142	64					
Kalaeloa CT 1	86	31					
Kalaeloa CT 2	86	31					
Kalaeloa ST	41	11					
Waiau 7	83	24					
Waiau 8	86	24					
Waiau 3	47	24					
Waiau 4	46	24					
HRRP 1	46	35	35	35			
AES	201	67	80	100	120	140	160
Total Thermal			243	243	242	244	249
Wind			99	99	99	99	99
PV - DG			408	408	408	408	408
PV - Station			10	10	10	10	10
Total Renewable			517	517	517	517	517
Total Gen			760	760	759	761	766
Load			752	752	752	752	752
Losses (assumed)			8.1	8.1	8.1	8.1	8.1
Total Gen Needed			760.1	760.1	760.1	760.1	760.1
Reg UP Required			135	135	135	135	135
Reg Up Available			325	235	190	188	183
Reg Down Available			29	53	87	89	94

Table D-5. 2015 Day Minimum Generation Dispatch

Details for the day peak generation dispatches are shown below in Table D-6. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the day peak cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2015 Values		2015											
			Day Peak						Day Peak, max units					
	Pmax	Pmin												
Kahe 1	86	24	86	81	81	74	67	60	35	30	24	24	24	24
Kahe 2	86	24	86	81	81	74	67	60	35	35	24	24	24	24
Kahe 3	90	24	90	81	81	74	67	60	35	35	32	24	24	24
Kahe 4	89	24	89	89	89	89	89	89	35	35	35	24	24	24
Kahe 5	142	65	110	110	90	90	90	90	100	100	100	100	92	85
Kahe 6	142	64							100	100	100	100	92	85
Kalaeloa CT 1	86	31	31	31	31	31	31	31	31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11	11	11	11	11	11	11	11	11	11	11	11	11
Waiau 7	83	24							35	24	24	24	24	24
Waiau 8	86	24							30	24	24	24	24	24
Waiau 3	47	24							24	24	24	24	24	24
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	46	46	46	46	46	35
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			649	650	650	649	648	647	648	646	646	647	651	646
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			408	408	408	408	408	408	408	408	408	408	408	408
PV - Station			10	10	10	10	10	10	10	10	10	10	10	10
Total Renewable			517	517	517	517	517	517	517	517	517	517	517	517
Total Gen			1166	1167	1167	1166	1165	1164	1165	1163	1163	1164	1168	1163
Load			1151	1151	1151	1151	1151	1151	1151	1151	1151	1151	1151	1151
Losses (assumed)			15	15	15	15	15	15	13.7	13.7	13.7	13.7	13.7	13.7
Total Gen Needed			1166	1166	1166	1166	1166	1166	1165	1165	1165	1165	1165	1165
Reg UP Required			135	135	135	135	135	135	135	135	135	135	135	135
Reg Up Available			218	217	217	218	219	220	664	666	666	665	661	666
Reg Down Available			345	346	346	345	344	343	178	176	176	177	181	176

Table D-6. 2015 Day Peak Generation Dispatches

Details of the generation dispatches for the evening peak cases are shown in Table D-7.

Unit	2015 Values		2015					
	Pmax	Pmin	Evening Peak					
Kahe 1	86	24	86	86	86	86	86	86
Kahe 2	86	24	86	86	86	86	86	86
Kahe 3	90	24	90	90	90	90	90	90
Kahe 4	89	24	86	86	86	86	86	86
Kahe 5	142	65	90	102	117	107	97	87
Kahe 6	142	64	90	102	117	107	97	87
Kalaeloa CT 1	86	31	86	86	86	86	86	86
Kalaeloa CT 2	86	31	86	86	86	86	86	86
Kalaeloa ST	41	11	41	41	41	41	41	41
Waiau 7	83	24	83	83	83	83	83	83
Waiau 8	86	24	86	86	86	86	86	86
Waiau 3	47	24	47	47				
Waiau 4	46	24	47					
HRRP 1	46	35	46	46	46	46	46	46
AES	201	67	100	120	140	160	180	200
Total Thermal			1150	1147	1150	1150	1150	1150
Wind			99	99	99	99	99	99
PV - DG			0	0	0	0	0	0
PV - Station			0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99
Total Gen			1249	1246	1249	1249	1249	1249
Load			1222	1222	1222	1222	1222	1222
Losses (assumed)			27	27	27	27	27	27
Total Gen Needed			1249	1249	1249	1249	1249	1249
Reg UP Required			50	50	50	50	50	50
Reg Up Available			208	165	115	115	115	115
Reg Down Available			656	677	704	704	704	704

Table D-7. 2015 Evening Peak Generation Dispatches

Details for the night minimum generation dispatches are shown below in Table D-8. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the night minimum cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2015 Values		2015											
			Night Minimum						Night Minimum, max units					
	Pmax	Pmin												
Kahe 1	86	24							24	24				
Kahe 2	86	24	40	24					24	24	24			
Kahe 3	90	24	90	90	90	80	70	60	24	24	24	24		
Kahe 4	89	24	89	89	89	80	70	60	24	24	24	24	24	24
Kahe 5	142	65	100	96	100	100	100	100	65	70	72	75	75	67
Kahe 6	142	64							64	70	72	75	75	67
Kalaeloa CT 1	86	31							31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11							11	11	11	11	11	11
Waiau 7	83	24							32					
Waiau 8	86	24												
Waiau 3	47	24												
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	35	35	35	35	35	35
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			465	465	465	466	466	466	465	464	464	466	462	466
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			0	0	0	0	0	0	0	0	0	0	0	0
PV - Station			0	0	0	0	0	0	0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99	99	99	99	99	99	99
Total Gen			564	564	564	565	565	565	564	563	563	565	561	565
Load			554	554	554	554	554	554	554	554	554	554	554	554
Losses (assumed)			10	10	10	10	10	10	10	10	10	10	10	10
Total Gen Needed			564	564	564	564	564	564	564	564	564	564	564	564
Reg UP Required			50	50	50	50	50	50	50	50	50	50	50	50
Reg Up Available			189	189	103	102	102	102	713	631	545	457	371	367
Reg Down Available			227	227	251	252	252	252	43	65	89	115	135	139

Table D-8. 2015 Night Minimum Generation Dispatches

2015: Results: Analysis

The results for the 2015 cases are organized by load case below. To aid in analyzing the results, a coloring scheme was added to the tables to easily show the minimum frequencies found during the simulation. The coloring scheme is shown in Table D-9 below.

Stage	1	58.9
Stage	2	58.7
Stage	3	58.4
Stage	4	58.1
Stage	5	57.8

Table D-9. 2015 Results Key: UFLS Stages

2015 Results: Day Minimum

The stability Zone 1 clearing results for the day minimum cases are shown below in Table D-10. The results show that 60 MW of legacy PV on the system result in Stage 1 UFLS activation for some Zone 1 transmission line contingencies, due to a loss of the PV during the transient system response. Reducing the amount of legacy PV to 40 MW eliminates the UFLS activation for transmission contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system. Note that HRRP is turned off when AES output is increased to 120 MW and above, thereby mitigating the severity of this disturbance.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL" d0	"ARCH2SCHO" d1	"ARCH2KEWA" d2	"CEIP2KAHE" d3	"CEIP2AES" d4	"CEIP2EWA" d5	"HALA2IWIL" d6	"HALA2KAHE" d7	"HALA2KOOL" d8	"HALA2MAKA" d9	"HALA2SCHO" d10	"IWIL2SCHO" d11	"IWIL2AIRP" d12	"KAHE2KAHE" d13	"KAHE2WAHI" d14	"KAHE2WAIA" d15	"KOOL2PUKE" d16	"KOOL2WAIA" d17	"MAKA2WAIA" d18	"MAKA2AIRP" d19	"WAHI2WAIA" d20	"WAIA2EWA" d21	"KAMO2KEWA" d22	"KALA2AES" d23	"KALA2EWA" d24	"HRRP2AES" d25
day min	40	80	60.0	60.0	60.0	59.9	59.9	59.9	60.0	60.0	59.9	60.0	60.0	60.0	60.0	60.0	59.9	59.9	60.0	60.0	59.9	60.0	59.9	59.9	60.0	59.9	59.9	58.9
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.8	59.9	60.0	59.9	59.9	58.7
		120	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.8	59.9	59.3	59.5	59.0	59.0
		140	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.1	59.0	59.0	59.9	59.9	59.9	59.9	59.8	59.9	59.3	59.0	59.0	59.9
		160	59.9	59.9	59.9	59.0	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.1	59.0	59.0	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.0	59.0	59.9
	60	80	60.0	60.0	60.0	59.9	59.9	59.9	60.0	60.0	59.9	60.0	60.0	60.0	60.0	60.0	59.9	59.9	60.0	60.0	59.9	60.0	59.9	59.9	60.0	59.9	59.9	58.8
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.8	59.9	60.0	59.9	59.9	58.6
		120	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.8	59.9	58.9	59.3	58.8	58.8
		140	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.8	59.9	58.9	58.8	58.8	59.9
		160	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	58.8	58.8	58.8	59.9	59.9	59.9	59.9	59.9	59.9	58.9	58.8	58.8	59.9

Table D-10. 2015 Stability Results: Day Minimum; Zone 1 Clearing

The stability AES trip and Zone 2 clearing results for the day minimum cases are shown below in Table D-11. Zone 2 clearing for transmission faults result in UFLS activation to Stage 1 and Stage 2 for many lines, with increased UFLS activation occurring as AES output is increased. Reducing the amount of legacy PV from 60 MW to 40 MW reduces the severity of these contingencies, resulting in a reduction in UFLS activation for some cases and an improved system response. Note that a fault and trip of the Waiau – Makalapa and Halawa – School lines with AES at 160 MW output results in all 5 Stages of UFLS activating for legacy PV amounts of 60 MW and 40 MW.

Case	# Legacy (MW)	AES Outage	"KAHE-WAHI" d26	"KAHE-HAL1" d27	"KAHE-HAL2" d28	"WAIA-WAHI" d29	"WAIA-MAKA" d30	"HALA-MAKA" d31	"HALA-SCHO" d32	"HALA-IWIL" d33
day min	40	80	59.5	59.2	59.2	59.8	59.2	59.2	59.2	59.2
		100	59.0	59.0	59.0	58.9	58.9	58.9	58.9	58.9
		120	58.9	58.9	58.9	58.9	58.9	58.9	58.9	58.9
		140	58.9	58.9	58.9	58.9	58.8	58.8	58.9	58.9
		160	58.9	58.9	58.9	58.9	54.9	55.1	58.8	58.9
	60	80	59.4	58.9	58.9	59.7	58.9	58.9	58.9	58.9
		100	58.8	58.8	58.8	58.7	58.7	58.7	58.7	58.8
		120	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7
		140	58.8	58.7	58.7	58.7	58.6	58.6	58.7	58.7
		160	58.8	58.7	58.7	58.7	55.0	55.1	58.6	58.6
				Zone 2 Clearing						

Table D-11. 2015 Stability Results: Day Minimum; Zone 2 Clearing

The results for a trip of AES for the day minimum cases are shown below in Table D-12. The results show that a trip of AES at 80 MW results in UFLS activation to Stage 4 with 60 MW of legacy PV. Further increases in AES output result in additional stages of UFLS activation. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response. Utilizing a transfer-trip scheme for UFLS Stages 1 and 2 has a minor impact on the results.

Load	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day min	40	80	58.3	58.3	58.4
		100	57.9	58.0	58.0
		120	57.7	57.7	57.7
		140	57.1	57.1	57.1
		160	56.5	56.5	56.6
	60	80	58.1	58.1	58.3
		100	57.8	57.8	57.8
		120	57.3	57.4	57.4
		140	56.6	56.6	56.6
		160	55.9	55.9	56.0

Table D-12. 2015 Results: Day Minimum; AES Trip

2015 Results: Day Peak

The stability Zone 1 clearing results for the day peak cases are shown below in Table D-13. The results show that using 60 MW or 40 MW of legacy PV on the system does not result in any UFLS activation for Zone 1 transmission line contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system, resulting in Stage 1 UFLS activation for this contingency.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL"	"ARCH2SCHO"	"ARCH2KEWA"	"CEIP2KAHE"	"CEIP2AES"	"CEIP2EWA"	"HALA2IWIL"	"HALA2KAHE"	"HALA2KOOL"	"HALA2MAKA"	"HALA2SCHO"	"IWIL2SCHO"	"IWIL2AIRP"	"KAHE2KAHE"	"KAHE2WAHI"	"KAHE2WAIA"	"KOOL2PUKE"	"KOOL2WAIA"	"MAKA2WAIA"	"MAKA2AIRP"	"WAHI2WAIA"	"WAIA2EWA"	"KAMO2KEWA"	"KALA2AES"	"KALA2EWA"	"HRRP2AES"
			d0	d1	d2	d3	d4	d5	d6	d7	d8	d9	d10	d11	d12	d13	d14	d15	d16	d17	d18	d19	d20	d21	d22	d23	d24	d25
day peak	40	100	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.4	59.4	58.9
		120	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.5	59.5	59.1
		140	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.5	59.5	59.3
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.4	60.0	59.3	59.3	58.9
		180	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.6	60.0	59.5	59.5	59.3
		200	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.4	59.4	59.9	59.9	59.9	59.9	59.9	59.7	60.0	59.4	59.4	58.9
	60	100	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.8	59.9	59.2	60.0	59.2	59.2	58.8
		120	59.9	59.9	59.9	59.2	59.2	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.3	60.0	59.2	59.3	58.9
		140	59.9	59.9	59.9	59.2	59.2	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.4	60.0	59.3	59.3	58.9
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.4	60.0	59.3	59.3	58.9
		180	59.9	59.9	59.9	59.2	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.3	59.9	59.9	59.9	59.9	59.9	59.5	60.0	59.3	59.3	58.9
		200	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.2	59.2	59.2	59.9	59.9	59.9	59.9	59.9	59.7	60.0	59.2	59.2	58.9

Table D-13. 2015 Stability Results: Day Peak; Zone 1 Clearing

The stability Zone 2 clearing results for the day peak cases are shown below in Table D-14. Zone 2 clearing for transmission faults result in UFLS activation to Stage 1 and Stage 2 for many lines, with increased UFLS activation occurring as AES output is increased. Reducing the amount of legacy PV from 60 MW to 40 MW reduces the severity of these contingencies, resulting in a reduction in UFLS activation for some cases and an improved system response. Note that a fault and trip of the Waiau–Makalapa and Halawa–School lines with AES at 180–200 MW output results in Stage 1 of UFLS activating for legacy PV amounts of 60 MW. The UFLS activation is eliminated when the legacy PV amount is reduced to 40 MW.

Case	# Legacy (MW)	AES Outage	"KAHE-WAHI" d26	"KAHE-HAL1" d27	"KAHE-HAL2" d28	"WAIA-WAHI" d29	"WAIA-MAKA" d30	"HALA-MAKA" d31	"HALA-SCHO" d32	"HALA-IWIL" d33
day peak	40	100	59.4	59.4	59.4	59.3	59.2	59.2	59.3	59.3
		120	59.4	59.4	59.4	59.4	59.2	59.2	59.3	59.3
		140	59.4	59.4	59.4	59.4	59.2	59.2	59.3	59.3
		160	59.2	59.2	59.2	59.2	58.9	58.9	59.1	59.1
		180	59.4	59.4	59.4	59.4	59.2	59.2	59.3	59.3
		200	59.3	59.3	59.3	59.3	59.1	59.1	59.2	59.2
	60	100	59.1	59.1	59.1	59.1	58.9	58.9	59.0	59.0
		120	59.2	59.1	59.1	59.2	58.9	59.0	59.0	59.0
		140	59.2	59.1	59.1	59.2	58.9	58.9	59.0	59.0
		160	59.2	59.2	59.2	59.2	58.9	58.9	59.1	59.1
		180	59.2	59.1	59.2	59.2	58.9	58.9	59.0	59.0
		200	59.1	59.1	59.1	59.1	58.9	58.9	59.0	59.0
				Zone 2 Clearing						

Table D-14. 2015 Stability Results: Day Peak; Zone 2 Clearing

The results for a trip of AES for the day peak and day peak maximum unit dispatch cases are shown below in Table D-15. The results show that for the day peak dispatch, a trip of AES at 100 MW results in UFLS activation to Stage 2 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 3. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response.

The day peak maximum unit dispatch results show that a trip of AES at 100 MW results in UFLS activation to Stage 1 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 2. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation for some cases.

Load	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day peak	40	100	58.6	58.7	59.8
		120	58.6	58.6	59.6
		140	58.4	58.4	58.5
		160	58.3	58.3	58.3
		180	58.3	58.3	58.3
		200	58.2	58.2	58.3
	60	100	58.5	58.6	59.8
		120	58.4	58.4	59.6
		140	58.3	58.4	58.4
		160	58.3	58.3	58.3
		180	58.2	58.2	58.3
		200	58.1	58.1	58.1
day peak max units	40	100	58.9	59.6	59.9
		120	58.9	59.4	59.7
		140	58.8	59.0	59.5
		160	58.7	58.8	59.4
		180	58.6	58.7	58.9
		200	58.5	58.6	58.7
	60	100	58.9	59.6	59.9
		120	58.8	59.4	59.7
		140	58.7	58.8	59.5
		160	58.6	58.7	59.4
		180	58.5	58.6	58.8
		200	58.4	58.5	58.6

Table D-15. 2015 Results: Day Peak

2015 Results: Evening Peak

The results for a trip of AES for the evening peak cases are shown below in Table D-16. The results show that a trip of AES at 100 MW results in no UFLS activation. Further increases in AES output result in additional stages of UFLS activation up to Stage 2. Utilizing a transfer-trip scheme for UFLS Stage 1 has a minor impact on the results, allowing for only 1 stage of UFLS activated for AES at 180 MW output, instead of 2 stages.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Evening Peak	100	59.1	59.8	59.9
	120	58.9	59.5	59.9
	140	58.9	59.3	59.8
	160	58.8	59.0	59.6
	180	58.7	58.7	59.4
	200	58.7	58.7	59.2

Table D-16. 2015 Results: Evening Peak

2015 Results: Night Minimum

The results for a trip of AES for the night minimum cases are shown below in Table D-17. The results show that a trip of AES at 100 MW results in Stage 2 UFLS activation. Further increases in AES output result in additional stages of UFLS activation up to Stage 4. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results.

The night minimum maximum units dispatch results show that a trip of AES at 100 MW results in no UFLS activation. Further increases in AES output result in additional stages of UFLS activation, up to Stage 4. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Night Minimum	100	58.6	58.7	59.0
	120	58.4	58.4	58.5
	140	58.1	58.2	58.2
	160	58.0	58.1	58.1
	180	58.0	58.0	58.0
	200	57.8	57.9	57.9
Night Minimum, Max Units	100	59.0	59.3	59.5
	120	58.8	58.9	59.2
	140	58.6	58.7	58.9
	160	58.4	58.4	58.4
	180	58.1	58.1	58.2
	200	58.0	58.1	58.1

Table D-17. 2015 Results: Night Minimum

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Power flow cases were created for the day minimum, day peak, evening peak, and night minimum load times. Specifics for each case are shown below in Table D-18.

Values	2016 Load Cases			
	Day Minimum	Day Peak	Evening Peak	Night Minimum
DG PV	450	450	0	0
Station PV	10	10	0	0
Wind	99	99	99	99
Load	752	1151	1222	554
Losses	8	15	27	10
Thermal Generation	201	607	1150	465
Regulation	143	143	50	50

Table D-18. 2016 Case Specifics

It was assumed for the 2016 cases that the Hawaiian Electric protection system was upgraded such that transmission line contingencies will no longer result in Zone 2 clearing.

2016 Generation Dispatches

Generation dispatches were created for each case, increasing AES output from a low value (80–100 MW) to the maximum possible output in 20 MW increments. Details of the generation dispatches for the daytime minimum cases are shown in Table D-19.

Unit	2016 Values		2016				
			Day Min				
	Pmax	Pmin					
Kahe 1	86	10	10	10	10		
Kahe 2	86	10	10	10	10	10	
Kahe 3	90	10	10	10	10	10	
Kahe 4	89	10	10	10	10	10	10
Kahe 5	142	25	45	25	40	30	30
Kahe 6	142	45					
Kalaeloa CT 1	86	31					
Kalaeloa CT 2	86	31					
Kalaeloa ST	41	11					
Waiau 7	83	10					
Waiau 8	86	10					
Waiau 3	47	24					
Waiau 4	46	24					
HRRP 1	46	35	35	35			
AES	201	67	80	100	120	140	160
Total Thermal			200	200	200	200	200
Wind			99	99	99	99	99
PV - DG			450	450	450	450	450
PV - Station			10	10	10	10	10
Total Renewable			559	559	559	559	559
Total Gen			759	759	759	759	759
Load			752	752	752	752	752
Losses (assumed)			8.1	8.1	8.1	8.1	8.1
Total Gen Needed			760	760	760	760	760
Reg UP Required			143	142	142	142	142
Reg Up Available			540	540	494	408	232
Reg Down Available			33	33	68	78	98

Table D-19. 2016 Day Minimum Generation Dispatch

Details for the day peak generation dispatches are shown below in Table D-20. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the day peak cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2016 Values		2016											
			Day Peak						Day Peak, max units					
	Pmax	Pmin												
Kahe 1	86	10	80	75	70	65	60	55	50	45	40	35	30	25
Kahe 2	86	10	80	75	70	65	60	55	50	45	40	35	30	25
Kahe 3	90	10	80	75	70	65	60	55	50	45	40	35	30	25
Kahe 4	89	10	85	80	75	70	65	60	50	45	40	35	30	25
Kahe 5	142	25	100	100	100	100	100	100	95	95	95	95	95	95
Kahe 6	142	45							95	95	95	95	95	95
Kalaeloa CT 1	86	31	31	31	31	31	31	31	31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11	11	11	11	11	11	11	11	11	11	11	11	11
Waiau 7	83	10												
Waiau 8	86	10												
Waiau 3	47	24												
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	46	46	46	46	46	46
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			613	613	613	613	613	613	609	609	609	609	609	609
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			450	450	450	450	450	450	450	450	450	450	450	450
PV - Station			10	10	10	10	10	10	10	10	10	10	10	10
Total Renewable			559	559	559	559	559	559	559	559	559	559	559	559
Total Gen			1172	1172	1172	1172	1172	1172	1168	1168	1168	1168	1168	1168
Load			1157	1157	1157	1157	1157	1157	1151	1157	1157	1157	1157	1157
Losses (assumed)			15	15	15	15	15	15	13.7	13.7	13.7	13.7	13.7	13.7
Total Gen Needed			1172	1172	1172	1172	1172	1172	1165	1171	1171	1171	1171	1171
Reg UP Required			142	142	142	142	142	142	142	142	142	142	142	142
Reg Up Available			254	254	254	254	254	254	486	486	486	486	486	486
Reg Down Available			404	404	404	404	404	404	324	324	324	324	324	324

Table D-20. 2016 Day Peak Generation Dispatches

Details of the generation dispatches for the evening peak cases are shown in Table D-21.

Unit	2016 Values		2016 Evening Peak					
	Pmax	Pmin						
Kahe 1	86	10	86	86	86	86	86	86
Kahe 2	86	10	86	86	86	86	86	86
Kahe 3	90	10	90	90	90	90	90	90
Kahe 4	89	10	86	86	86	86	86	86
Kahe 5	142	25	90	102	117	107	97	87
Kahe 6	142	45	90	102	117	107	97	87
Kalaeloa CT 1	86	31	86	86	86	86	86	86
Kalaeloa CT 2	86	31	86	86	86	86	86	86
Kalaeloa ST	41	11	41	41	41	41	41	41
Waiau 7	83	10	83	83	83	83	83	83
Waiau 8	86	10	86	86	86	86	86	86
Waiau 3	47	24	47	47				
Waiau 4	46	24	47					
HRRP 1	46	35	46	46	46	46	46	46
AES	201	67	100	120	140	160	180	200
Total Thermal			1150	1147	1150	1150	1150	1150
Wind			99	99	99	99	99	99
PV - DG			0	0	0	0	0	0
PV - Station			0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99
Total Gen			1249	1246	1249	1249	1249	1249
Load			1222	1222	1222	1222	1222	1222
Losses (assumed)			27	27	27	27	27	27
Total Gen Needed			1249	1249	1249	1249	1249	1249
Reg UP Required			50	50	50	50	50	50
Reg Up Available			208	165	115	115	115	115
Reg Down Available			798	818	845	845	845	845

Table D-21. 2016 Evening Peak Generation Dispatches

Details for the night minimum generation dispatches are shown below in Table D-22. Due to the possibility of generation dispatches being adjusted as to have more units online for system support, the night minimum cases were run with two different dispatches, a minimum unit case, and a maximum unit case.

Unit	2016 Values		2016											
			Night Minimum						Night Minimum, max units					
	Pmax	Pmin												
Kahe 1	86	10							24	10	10	10	10	10
Kahe 2	86	10	55	35	15	10	10	10	24	15	10	10	10	10
Kahe 3	90	10	90	90	90	85	65	45	24	24	10	10	10	10
Kahe 4	89	10	89	89	89	80	80	80	24	24	24	10	10	10
Kahe 5	142	25	100	100	100	100	100	100	90	90	90	85	75	65
Kahe 6	142	45							90	90	90	85	75	65
Kalaeloa CT 1	86	31							31	31	31	31	31	31
Kalaeloa CT 2	86	31							31	31	31	31	31	31
Kalaeloa ST	41	11							11	11	11	11	11	11
Waiau 7	83	10												
Waiau 8	86	10												
Waiau 3	47	24												
Waiau 4	46	24												
HRRP 1	46	35	46	46	46	46	46	46	35	35	35	35	35	35
AES	201	67	100	120	140	160	180	200	100	120	140	160	180	200
Total Thermal			480	480	480	481	481	481	484	481	482	478	478	478
Wind			99	99	99	99	99	99	99	99	99	99	99	99
PV - DG			0	0	0	0	0	0	0	0	0	0	0	0
PV - Station			0	0	0	0	0	0	0	0	0	0	0	0
Total Renewable			99	99	99	99	99	99	99	99	99	99	99	99
Total Gen			579	579	579	580	580	580	583	580	581	577	577	577
Load			570	570	570	570	570	570	570	570	570	570	570	570
Losses (assumed)			10	10	10	10	10	10	10	10	10	10	10	10
Total Gen Needed			580	580	580	580	580	580	580	580	580	580	580	580
Reg UP Required			50	50	50	50	50	50	50	50	50	50	50	50
Reg Up Available			174	174	174	173	173	173	611	614	613	617	617	617
Reg Down Available			323	323	323	324	324	324	199	196	197	193	193	193

Table D-22. 2016 Night Minimum Generation Dispatches

2016 Results

The results for the 2016 cases are organized by load case below. To aid in analyzing the results, a coloring scheme was added to the tables to easily show the minimum frequencies found during the simulation. The coloring scheme is shown in Table D-23 below.

Stage	1	58.9
Stage	2	58.7
Stage	3	58.4
Stage	4	58.1
Stage	5	57.8

Table D-23. 2016 Results: Key UFLS Stages

2016 Results: Day Minimum

The stability results for the day minimum cases are shown below in Table D-24. The results show that 60 MW and 40 MW of legacy PV on the system result no UFLS activation for transmission line contingencies. Reducing the amount of legacy PV to 40 MW eliminates the UFLS activation for transmission contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system. Note that HRRP is turned off when AES output is increased to 120 MW and above, thereby mitigating the severity of this disturbance.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL"	"ARCH2SCHO"	"ARCH2KEWA"	"CEIP2KAHE"	"CEIP2AES"	"CEIP2EWA"	"HALA2IWIL"	"HALA2KAHE"	"HALA2KOOL"	"HALA2MAKA"	"HALA2SCHO"	"IWIL2SCHO"	"IWIL2AIRP"	"KAHE2KAHE"	"KAHE2WAHI"	"KAHE2WAIA"	"KOOL2PUKE"	"KOOL2WAIA"	"MAKA2WAIA"	"MAKA2AIRP"	"WAHI2WAIA"	"WAIA2EWA"	"KAMO2KEWA"	"KALA2AES"	"KALA2EWA"	"HRRP2AES"
			d0	d1	d2	d3	d4	d5	d6	d7	d8	d9	d10	d11	d12	d13	d14	d15	d16	d17	d18	d19	d20	d21	d22	d23	d24	d25
day min	40	80	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		120	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	60.0	59.9	59.9	59.9	59.9	59.9	59.8	59.8	59.8
		140	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	60.0	59.9	59.9	59.9	59.9	60.0	59.8	59.8	59.8
		160	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.9	59.9	59.9
	60	80	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		100	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.4	59.4	59.9	59.9	59.8	59.9	59.9	59.8	59.8	59.5
		120	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.9	59.9	59.9	59.8	59.8	59.8
		140	59.9	59.9	59.9	59.8	59.8	59.8	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.7	59.7	59.9	59.9	59.9	59.9	60.0	59.8	59.8	59.8
		160	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.9	59.9	59.9

Table D-24. 2016 Stability Results: Day Minimum

Note that no Zone 2 clearing analysis was completed for the 2016 cases as it is assumed that protection settings and equipment have been upgraded to eliminate the need for Zone 2 clearing for transmission line faults.

The results for a trip of AES for the day minimum cases are shown below in Table D-25. The results show that a trip of AES at 80 MW results in UFLS activation to Stage 3 with 60 MW of legacy PV. Further increases in AES output result in additional stages of UFLS activation. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response, activating only to stage 2 for a trip of AES at 80 MW. Utilizing a transfer-trip scheme for UFLS Stages 1 and 2 has a minor impact on the results.

Season	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day min	40	80	58.5	58.5	59.3
		100	58.3	58.3	58.4
		120	58.0	58.0	58.1
		140	57.6	57.6	57.7
		160	55.1	55.1	55.2
	60	80	58.3	58.4	59.4
		100	58.1	58.2	58.2
		120	57.9	57.9	58.0
		140	57.3	57.4	57.5
		160	54.4	54.4	54.5

Table D-25. 2016 Results: Day Minimum

2016 Results: Day Peak

The stability results for the day peak cases are shown below in Table D-26. The results show that using 60 MW or 40 MW of legacy PV on the system does not result in any UFLS activation for contingencies. Note that contingency d25, HRRP2AES, is a transmission line fault and trip that results in a loss of generation at HRRP to the rest of the Hawaiian Electric system.

Case	# Legacy (MW)	AES Outage	"ARCH2IWIL" d0	"ARCH2SCHO" d1	"ARCH2KEWA" d2	"CEIP2KAHE" d3	"CEIP2AES" d4	"CEIP2EWA" d5	"HALA2IWIL" d6	"HALA2KAHE" d7	"HALA2KOOL" d8	"HALA2MAKA" d9	"HALA2SCHO" d10	"IWIL2SCHO" d11	"IWIL2AIRP" d12	"KAHE2KAHE" d13	"KAHE2WAHI" d14	"KAHE2WAIA" d15	"KOOL2PUKE" d16	"KOOL2WAIA" d17	"MAKA2WAIA" d18	"MAKA2AIRP" d19	"WAHI2WAIA" d20	"WAIA2EWA" d21	"KAMO2KEWA" d22	"KALA2AES" d23	"KALA2EWA" d24	"HRRP2AES" d25
day peak	40	100	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
		120	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
		140	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		180	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.6	59.4
		200	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.5	59.5	59.5	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.5	59.5	59.4
	60	100	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.3	59.4
		120	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		140	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		160	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4
		180	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.4	59.4	59.4
		200	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	59.9	59.3	59.3	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.0	59.3	59.4	59.4

Table D-26. 2016 Stability Results: Day Peak Zone 1 Clearing

Note that no Zone 2 clearing analysis was completed for the 2016 cases as it is assumed that protection settings and equipment have been upgraded to eliminate the need for Zone 2 clearing for transmission line faults.

The results for a trip of AES for the day peak and day peak maximum unit dispatch cases are shown below in Table D-27. The results show that for the day peak dispatch, a trip of

AES at 100 MW results in UFLS activation to Stage 2 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 4. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response, mitigating the need for Stage 4 UFLS activation for an AES trip at 200 MW.

The day peak maximum unit dispatch results show that a trip of AES at 100 MW results in UFLS activation to Stage 1 with 60 MW of legacy PV. Further increases in AES output result in a maximum UFLS activation of Stage 3. Decreasing the amount of legacy PV from 60 MW to 40 MW results in a slight improvement in system response. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation.

Load	Legacy PV	AES Trip (MW)	Transfer Trip UFLS		
			None	Stage 1	Stage 1 and 2
day peak	40	100	58.6	58.7	59.8
		120	58.6	58.6	59.6
		140	58.4	58.4	58.5
		160	58.3	58.3	58.3
		180	58.3	58.3	58.3
		200	58.2	58.2	58.3
	60	100	58.5	58.6	59.8
		120	58.4	58.4	59.6
		140	58.3	58.4	58.4
		160	58.3	58.3	58.3
		180	58.2	58.2	58.3
		200	58.1	58.1	58.1
day peak max units	40	100	58.9	59.6	59.9
		120	58.9	59.4	59.7
		140	58.8	59.0	59.5
		160	58.7	58.8	59.4
		180	58.6	58.7	58.9
		200	58.5	58.6	58.7
	60	100	58.9	59.6	59.9
		120	58.8	59.4	59.7
		140	58.7	58.8	59.5
		160	58.6	58.7	59.4
		180	58.5	58.6	58.8
		200	58.4	58.5	58.6

Table D-27. 2016 Results: Day Peak

2016 Results: Evening Peak

The results for a trip of AES for the evening peak cases are shown below in Table D-28. The results show that a trip of AES at 100 MW results in no UFLS activation. Further increases in AES output result in increased UFLS activation, to stage 2. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation for some cases.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Evening Peak	100	59.1	59.8	59.9
	120	58.9	59.5	59.9
	140	58.9	59.3	59.8
	160	58.8	59.0	59.6
	180	58.7	58.7	59.4
	200	58.7	58.7	59.2

Table D-28. 2016 Results: Evening Peak

2016 Results: Night Minimum

The results for a trip of AES for the night minimum cases are shown below in Table D-29. The results show that a trip of AES at 100 MW results in Stage 2 UFLS activation. Further increases in AES output result in additional stages of UFLS activation up to Stage 4. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results.

The night minimum maximum units dispatch results show that a trip of AES at 100 MW results in Stage 1 activation. Further increases in AES output result in additional stages of UFLS activation, up to Stage 3. Utilizing a transfer-trip scheme for UFLS stages 1 and 2 has a minor impact on the results, allowing for increases of AES output by 20 MW without increasing UFLS activation.

Load	AES Trip (MW)	Transfer Trip UFLS		
		None	Stage 1	Stage 1 and 2
Night Minimum	100	58.6	58.7	59.1
	120	58.4	58.4	58.5
	140	58.3	58.3	58.3
	160	58.2	58.2	58.3
	180	58.1	58.1	58.1
	200	58.0	58.0	58.0
	100	58.9	59.2	59.5
	120	58.8	59.0	59.3
	140	58.7	58.7	59.0
	160	58.5	58.6	58.7
	180	58.4	58.4	58.5
	200	58.3	58.4	58.4

Table D-29. 2016 Results: Night Minimum

YEAR 2017 ANALYSIS

Power flow cases were created for the day minimum and night minimum load times. The day minimum cases assumed a load of 752 MW, with renewable generation resources consisting of 471 MW of distributed PV (40 MW legacy PV), 272 MW of station PV, and 123 MW of wind. The night minimum cases assumed a load of 586 MW, utilizing only the wind as available renewable energy sources. A 60 MW BESS is assumed to be installed in 2017 for all cases.

Contract limitations for AES and KLPP were assumed to be 90 MW/180 MW for AES and one simple cycle turbine for KLPP respectively. For each of the dispatch scenarios, the largest unit was operated at full load prior to the contingency event.

For the purposes of the system security study, a 60 MW BESS was assumed to be operational in 2017. The BESS is assumed to have both droop response and auto-schedule response capabilities to control action.

2017 Generation Dispatches

The dispatches utilized AES, HRRP #1 & #2, and Kalaeloa CT #1 generation resources. Generation sensitivities included utilizing additional generation from Kalaeloa CT #2, Kahe 5, and Kahe 6. The AES unit was dispatched at 100 MW and 200 MW, while the other units were all dispatched at their minimum outputs. Details of the generation dispatches for the daytime minimum cases are shown in Table D-30.

Unit	1 Kalaeloa Train		2 Kalaeloa Train		2 Kalaeloa Train. 1 kpp		2 Kalaeloa Train. 2kpp	
	AES		AES		AES		AES	
	200	100	200	100	200	100	200	100
Kalaeloa CT1	15	15	25	25	25	25	25	25
Kalaeloa CT2	0	0	25	25	25	25	25	25
Kahe 5	0	0	0	0	25	25	25	25
Kahe 6	0	0	0	0	0	0	45	45
HRRP 1	25	25	25	25	25	25	25	25
HRRP 2	10	10	10	10	10	10	10	10
AES	200	100	200	100	200	100	200	100
Total Thermal	250	150	285	185	310	210	355	255
Wind	123	123	123	123	123	123	123	123
PV - DG	471	471	471	471	471	471	471	471
PV - Station	272	272	272	272	272	272	272	272
Total Renewable	866	866	866	866	866	866	866	866
RE Curtailed	349	249	384	284	409	309	454	354
Total Renewable available	517	617	482	582	457	557	412	512
Load - day min	752	752	752	752	752	752	752	752
Losses (assumed)	15	15	15	15	15	15	15	15

Table D-30. Day Minimum Generation Dispatch

Details for the night minimum generation dispatches are shown below in Table D-31.

Unit	night minimum	
	AES	
	200	100
Kalaeloa CT1	86	86
Kalaeloa CT2	86	86
Kalaeloa ST	41	41
Kahe 5	0	100
Kahe 6	0	0
HRRP 1	46	46
HRRP 2	25	25
AES	200	100
Total Thermal	484	484
Wind	123	123
PV - DG	0	0
PV - Station	0	0
Total Renewable	123	123
Total Renewable available	123	123
Load - day min	586	586
Losses (assumed)	15	15

Table D-31. Night Minimum Generation Dispatch

2017 Results

The day minimum cases show that for a 200 MW trip of AES, utilizing the 60 MW BESS assumed for 2017 operation requires an additional 120–140 MW of contingency reserves. For a 100 MW trip of AES, an additional 20–40 MW of contingency reserves is needed. Detailed results for the day minimum cases are shown below in Table D-32.

Station PV		AES	1 Kalaeloa CT			2 Kalaeloa CT's			2 Kalaeloa CT's, 1 Kahe			2 Kalaeloa CT's, 2 Kahe		
Avail	Curt	Trip (MW)	Cont Res MW	%	Min Freq (Hz)	Cont Res MW	%	Min Freq (Hz)	Cont Res MW	%	Min Freq (Hz)	Cont Res MW	%	Min Freq (Hz)
272	272	200	0	0	56.8	0	0%	57.7	0	0%	57.8	0	0%	58.0
			20	7%	57.6	20	7%	57.8	20	7%	58.0	20	7%	58.1
			40	15%	57.8	40	15%	58.0	40	15%	58.1	40	15%	58.3
			60	22%	57.9	60	22%	58.1	60	22%	58.3	60	22%	58.4
			80	29%	58.1	80	29%	58.3	80	29%	58.4	80	29%	58.6
			100	37%	58.3	100	37%	58.5	100	37%	58.7	100	37%	58.7
			120	44%	58.6	120	44%	58.7	120	44%	59.3	120	44%	59.5
			140	51%	59.9	140	51%	60.0	140	51%	60.0	140	51%	60.0
			160	59%	58.9	160	59%	59.1	160	59%	59.2	160	59%	59.4
		100	0	0%	58.2	0	0%	58.4	0	0%	58.5	0	0%	58.7
			20	7%	58.4	20	7%	58.6	20	7%	58.7	20	7%	59.4
			40	15%	59.9	40	15%	59.9	40	15%	60.0	40	15%	60.0
			60	22%	58.9	60	22%	58.9	60	22%	59.2	60	22%	59.3
			80	29%	59.8	80	29%	59.8	80	29%	59.9	80	29%	59.9
			100	37%	60.0	100	37%	60.0	100	37%	60.0	100	37%	60.0
			120	44%	60.0	120	44%	60.0	120	44%	60.0	120	44%	60.0
			140	51%	60.0	140	51%	60.0	140	51%	60.0	140	51%	60.0
			160	59%	60.0	160	59%	60.0	160	59%	60.0	160	59%	60.0

percent of curtailed station PV used for regulation
minimum ESS / Station PV regulation size
frequency below limits of 58.7 Hz

Table D-32. 2017 Day Minimum Detailed Results

The night minimum case results are shown in Table D-33, and show that for an AES trip of 200 MW, an additional 80 MW of contingency reserves is required. No additional contingency reserves are required for a trip of AES at 100 MW.

BESS Size	AES Trip	Cont Res MW	Min Freq (Hz)
60	200	0	58.2
		20	58.3
		40	58.4
		60	58.6
		80	58.8
		100	58.9
		120	59.3
		140	60.0
		160	60.0
	100	0	59.0
		20	59.5
		40	60.0
		60	60.0
		80	60.0
		100	60.0
		120	60.0
		140	60.0
		160	60.0

minimum ESS size
frequency below limits of 58.7

Table D-33. 2017 Night Minimum Detailed Results

YEAR 2022 ANALYSIS

Power flow cases were created for the day minimum load times. The day minimum cases assumed a load of 752 MW, with renewable generation resources consisting of 556 MW of distributed PV (40 MW legacy PV), 272 MW of station PV, and 123 MW of wind. A 60 MW BESS is assumed to be installed in 2017 and available for use in 2022.

Contract requirements for AES were assumed to be 90 MW/180 MW. Generation additions included the options of utilizing GE LM6000 or LMS100 combustion turbines, with nominal ratings of 55 MW and 95 MW, respectively.

2022 Generation Dispatches

The dispatches created all utilized AES dispatched at 100 MW or 200 MW, while the remaining generation support came from the new LM6000s or LMS100s identified in the PSIP preferred plan. The new units were dispatched at their minimum output of 12 MW. Details of the generation dispatches for the daytime minimum cases are shown in Table D-34.

Unit	LMS100				LM6000			
	1		2		2		3	
	AES		AES		AES		AES	
	200	100	200	100	200	100	200	100
LMS100 #1	12	12	12	12	-	-	-	-
LMS100 #2	-	-	12	12	-	-	-	-
LM6000 #1	-	-	-	-	12	12	12	12
LM6000 #2	-	-	-	-	12	12	12	12
LM6000 #2	-	-	-	-	-	-	12	12
AES	200	100	200	100	200	100	200	100
Total Thermal	212	112	224	124	224	124	236	136
Wind	123	123	123	123	123	123	123	123
PV - DG	556	556	556	556	556	556	556	556
PV - Station	272	272	272	272	272	272	272	272
Total Renewable	951	951	951	951	951	951	951	951
RE Curtailed	396	296	408	308	408	308	420	320
Total PV available	432	532	420	520	420	520	408	508
Total 57 available	392	492	380	480	380	480	368	468
Total Renewable available	555	655	543	643	543	643	531	631
Load - day min	752	752	752	752	752	752	752	752
Losses (assumed)	15	15	15	15	15	15	15	15

Table D-34. 2022 Day Minimum Generation Dispatch

2022 Results

The day minimum cases show that for a 200 MW trip of AES, utilizing the already installed 60 MW BESS requires an additional 140 MW of contingency reserves. For a

100 MW trip of AES, 40 MW of additional contingency reserves is needed. Detailed results for the day minimum cases using generation from LM6000s or LMS100s are shown below in Table D-35 and Table D-36, respectively.

Station PV		BESS Size (MW)	AES Unit Trip (MW)	LM6000							
				2				3			
				Cont Reserve		Unit Trip		Cont Reserve		Unit Trip	
Avail	Curt			MW	%	AES	Wind	MW	%	AES	Wind
272	272	60	100	0	0%	57.8	58.3	0	0%	58.1	58.4
				20	7%	58.2	58.6	20	7%	58.4	58.7
				40	15%	59.9	59.6	40	15%	59.9	59.7
				60	22%	58.7	60.0	60	22%	58.8	60.0
				80	29%	59.6	59.5	80	29%	59.6	59.5
				100	37%	60.0	60.0	100	37%	60.0	59.9
				120	44%	60.0	60.0	120	44%	60.0	60.0
				140	51%	60.0	60.0	140	51%	60.0	60.0
				160	59%	60.0	60.0	160	59%	60.0	60.0
			200	0	0%	55.4	58.3	0	0%	56.5	58.5
				20	7%	56.7	58.6	20	7%	57.1	58.7
				40	15%	57.0	59.6	40	15%	57.4	59.7
				60	22%	57.3	60.0	60	22%	57.7	60.0
				80	29%	57.6	59.5	80	29%	57.9	59.5
				100	37%	58.0	60.0	100	37%	58.2	59.9
				120	44%	58.2	60.0	120	44%	58.5	60.0
				140	51%	60.0	60.0	140	51%	59.9	60.0
				160	59%	58.8	60.0	160	59%	58.9	60.0

percent of curtailed station PV used for regulation
Additional Regulation from Station PV required
Simulation Results in frequency below 58.7 Hz

Table D-35. 2022 Day Minimum LM6000 Units Detailed Results

Station PV		BESS Size (MW)	AES Unit Trip (MW)	LMS100							
				1				2			
				Cont Reserve		Unit Trip		Cont Reserve		Unit Trip	
Avail	Curt			MW	%	AES	Wind	MW	%	AES	Wind
272	272	60	100	0	0%	57.7	58.3	0	0%	58.2	58.5
				20	7%	58.2	58.6	20	7%	58.5	58.8
				40	15%	59.9	59.6	40	15%	59.9	59.7
				60	22%	58.7	60.0	60	22%	58.9	60.0
				80	29%	59.6	59.5	80	29%	59.6	59.5
				100	37%	60.0	60.0	100	37%	60.0	59.8
				120	44%	60.0	60.0	120	44%	60.0	60.0
				140	51%	60.0	60.0	140	51%	60.0	60.0
				160	59%	60.0	60.0	160	59%	60.0	60.0
			200	0	0%	54.6	58.3	0	0%	56.5	58.5
				20	7%	56.2	58.6	20	7%	57.2	58.8
				40	15%	56.7	59.6	40	15%	57.5	59.7
				60	22%	57.2	60.0	60	22%	57.8	60.0
				80	29%	57.5	59.5	80	29%	58.0	59.6
				100	37%	57.9	60.0	100	37%	58.2	59.9
				120	44%	58.1	60.0	120	44%	58.6	60.0
				140	51%	60.0	60.0	140	51%	59.9	60.0
				160	59%	58.8	60.0	160	59%	59.0	60.0

percent of curtailed station PV used for regulation
Additional Regulation from Station PV required
Simulation Results in frequency below 58.7 Hz

Table D-36. 2022 Day Minimum LMS100 Units Detailed Results

YEAR 2030 ANALYSIS

Power flow cases were created for the day minimum load times. The day minimum cases assumed a load of 752 MW, with renewable generation resources consisting of 556 MW of distributed PV (40 MW legacy PV), 272 MW of station PV, and 123 MW of wind.

The 60 MW BESS assumed to be operational in 2017 is incorporated into this analysis as available for use in 2030.

Generation was assumed to be only from new generation resources of either GE LM6000s or LMS100s combustion turbines, with nominal ratings of 55 MW and 95 MW, respectively.

2030 Generation Dispatches

The dispatches created all utilized AES dispatched at 100 MW and 200 MW, while the remaining generation support came from the new LM6000s or LMS100s, dispatched at their minimum output of 12 MW. Details of the generation dispatches for the daytime minimum and daytime peak cases are shown in Table D-37.

Unit	Day Minimum				Day Peak			
	LM6000		LMS100		LM6000		LMS100	
	2	3	2	3	2	3	2	3
# of LM6000	2	3	-	-	2	3	-	-
# of LMS100	-	-	2	3	-	-	2	3
Total Thermal	110	165	190	285	110	165	190	285
Wind	123	123	123	123	123	123	123	123
PV - DG	556	556	556	556	556	556	556	556
PV - Station	272	272	272	272	272	272	272	272
Total Renewable	951	951	951	951	951	951	951	951
RE Curtailed	294	349	374	469	202	257	282	377
Total PV available	534	479	454	359	626	571	546	451
Total 57 available	494	439	414	319	586	531	506	411
Total Renewable available	657	602	577	482	749	694	669	574
Load - day min	752	752	752	752	844	844	844	844
Losses (assumed)	15	15	15	15	15	15	15	15

Table D-37. 2030 Day Minimum and Day Peak Generation Dispatches

Details of the generation dispatches for the evening peak and night time minimum cases are shown in Table D-38.

Unit	Evening Peak		Night Minimum	
	LM6000	LMS100	LM6000	LMS100
	14	8	9	5
# of LM6000	14	-	9	-
# of LMS100	-	8	-	5
Total Thermal	770	760	495	475
Wind	123	123	123	123
PV - DG	-	-	-	-
PV - Station	-	-	-	-
Total Renewable	123	123	123	123
RE Curtailed	-	-	-	-
Total PV available	-	-	-	-
Total 57 available	-	-	-	-
Total Renewable available	123	123	123	123
Load - day min	924	924	635	635
Losses (assumed)	15	15	15	15

Table D-38. 2030 Evening Peak and Night Minimum Generation Dispatches

2030 Results

Outages of the largest combustion turbine and wind generation facility were analyzed for each case. The day minimum cases show that for a generation dispatch of two or three LM6000's, a 100 MW trip of a wind generation facility will require an additional 40 MW of contingency reserves. Detailed results for the day minimum LM6000 cases are shown below in Table D-39.

Station PV		LM6000							
		2				3			
Avail	Curt	Cont Reserve		Disturbance		Cont Reserve		Disturbance	
		MW	%	Unit	Wind	MW	%	Unit	Wind
272	272	0	0%	60.0	58.1	0	0%	60.0	58.3
		20	7%	58.8	58.2	20	7%	59.1	58.5
		40	15%	60.0	59.5	40	15%	59.9	59.7
		60	22%	60.0	58.7	60	22%	60.0	58.8
		80	29%	60.0	59.3	80	29%	60.0	59.4
		100	37%	60.0	59.9	100	37%	60.0	59.9
		120	44%	60.0	60.0	120	44%	60.0	60.0
			percent of curtailed station PV used for regulation						
			Additional ESS / Regulation Required						
			Simulation Results in frequency below 58.7 Hz						

Table D-39. 2030 Day Minimum LM6000 Units Detailed Results

The day minimum cases show that for a generation dispatch of two or three LM100's, a 100 MW trip of a wind generation facility or of an LMS100 will require an additional 40 MW of contingency reserves. Detailed results for the day minimum LMS100 cases are shown below in Table D-40.

Station PV		LMS100							
		2				3			
Avail	Curt	Cont Reserve		Disturbance		Cont Reserve		Disturbance	
		MW	%	Unit	Wind	MW	%	Unit	Wind
272	272	0	0%	58.0	58.5	0	0%	58.5	58.6
		20	7%	58.4	58.7	20	7%	59.5	59.5
		40	15%	60.0	59.8	40	15%	60.0	59.9
		60	22%	59.2	59.0	60	22%	59.4	59.3
		80	29%	60.0	59.5	80	29%	59.9	59.7
		100	37%	60.0	59.9	100	37%	60.0	59.9
		120	44%	60.0	60.0	120	44%	60.0	60.0

(grey)	percent of curtailed station PV used for regulation
(blue-grey)	Additional ESS / Regulation Required
(pink)	Simulation Results in frequency below 58.7 Hz

Table D-40. 2030 Day Minimum LMS100 Units Detailed Results

The day peak cases show that for a generation dispatch three LM6000's, a 100 MW trip of a wind generation facility will require will require an additional 40 MW of contingency reserves. Detailed results for the day peak LM6000 cases are shown below in Table D-41.

Station PV		LM6000			
		3			
Avail	Curt	Cont Reserve		Disturbance	
		MW	%	Unit	Wind
272	272	0	0%	60.0	58.4
		20	7%	59.1	58.5
		40	15%	59.9	59.6
		60	22%	60.0	58.8
		80	29%	60.0	59.4
		100	37%	60.0	59.8
		120	44%	60.0	60.0

(grey)	percent of curtailed station PV used for regulation
(blue-grey)	Additional ESS / Regulation Required
(pink)	Simulation Results in frequency below 58.7 Hz

Table D-41. 2030 Day Peak LM6000 Units Detailed Results

The day peak cases show that for a generation dispatch of two or three LM100s, a 100 MW trip of a wind generation facility or of an LMS100 will require an additional 40 MW of contingency reserves. Detailed results for the day peak LMS100 cases are shown below in Table D-42.

Station PV		LMS100							
		2				3			
Avail	Curt	Cont Reserve		Disturbance		Cont Reserve		Disturbance	
		MW	%	Unit	Wind	MW	%	Unit	Wind
272	272	0	0%	58.1	58.5	0	0%	58.5	58.6
		20	7%	58.4	58.6	20	7%	59.5	59.5
		40	15%	60.0	59.7	40	15%	60.0	59.9
		60	22%	59.2	58.9	60	22%	59.4	59.2
		80	29%	60.0	59.5	80	29%	59.9	59.6
		100	37%	60.0	59.8	100	37%	60.0	59.9
		120	44%	60.0	60.0	120	44%	60.0	60.0
			percent of curtailed station PV used for regulation						
			Additional ESS / Regulation Required						
			Simulation Results in frequency below 58.7 Hz						
			marginal case, not recommended for sizing regulation needed						

Table D-42. 2030 Day Peak LMS100 Units Detailed Results

The evening peak cases show that for a generation dispatch utilizing either 14 LM6000s or 8 LMS100s results in no additional need for contingency reserves beyond the assumed to be installed 60 MW BESS. Detailed results for the evening peak cases are shown below in Table D-43.

LM6000			LMS100		
14			8		
Cont Reserve	Disturbance		Cont Reserve	Disturbance	
MW	Unit	Wind	MW	Unit	Wind
0	60.0	59.6	0	59.6	59.6
20	60.0	59.8	20	59.8	59.8
40	60.0	60.0	40	60.0	60.0
60	60.0	60.0	60	60.0	60.0
80	60.0	60.0	80	60.0	60.0
100	60.0	60.0	100	60.0	60.0
120	60.0	60.0	120	60.0	60.0
	Additional ESS / Required				
	Simulation Results in frequency below 58.7 Hz				

Table D-43. 2030 Evening Peak Detailed Results

The night minimum cases show that for a generation dispatch utilizing either 14 LM6000s or 8 LMS100s results in no additional need for contingency reserves beyond the assumed to be installed 60 MW BESS. Detailed results for the night minimum cases are shown below in Table D-44.

LM6000			LMS100		
9			5		
Cont Reserve	Disturbance		Cont Reserve	Disturbance	
MW	Unit	Wind	MW	Unit	Wind
0	60.0	59.4	0	59.4	59.5
20	60.0	59.7	20	59.7	59.8
40	60.0	60.0	40	60.0	60.0
60	60.0	60.0	60	60.0	60.0
80	60.0	60.0	80	60.0	60.0
100	60.0	60.0	100	60.0	60.0
120	60.0	60.0	120	60.0	60.0
	Additional ESS / Required				
	Simulation Results in frequency below 58.7 Hz				

Table D-44. 2030 Night Minimum Detailed Results

2030 Results: No Additional ESS Contingency Reserves

Further analysis determined the minimum number of units required to be online with contingency reserve resources limited to the 60 MW BESS for the day minimum cases. The analysis was completed utilizing LM6000 or LMS100 combustion turbines. Utilizing LM6000 units requires that at minimum 7 units be online in order to keep the system frequency above 58.7 Hz. Utilizing LMS100 units requires that a minimum of 5 units be online. The detailed results are shown below in Table D-45.

Case	BESS Size (MW)	Reg	LM6000			LMS100		
			# of Units	Contingency		# of Units	Contingency	
				LM6000	Wind		LMS100	Wind
day min	60	198	5	59.8	58.5	3	60.0	58.6
			6	60.0	58.6	4	58.6	58.8
			7	60.0	58.8	5	58.8	59.4
			8	60.0	59.4	6	59.4	59.5
			9	60.0	59.5	7	59.5	59.6
			10	60.0	59.5	-	-	-
				Minimum number of units required				
				Simulation Results in frequency below 58.7 Hz				

Table D-45. 2030 Minimum Number of Unit Analysis

CONCLUSIONS

EPS has completed analysis of the Hawaiian Electric system for the 2015–2030 time periods. These periods were chosen in order to determine the operation ability and any constraints on the operations of the Hawaiian Electric system before the addition of additional transmission infrastructure and energy storage systems that are expected to come online in 2017, and after improvements have been made.

2015–2016 Cases

The results of the analysis show that there is a benefit to the system in reducing the amount of legacy PV from 60 MW to 40 MW of total output. The reduction in legacy PV can decrease the amount of UFLS activation during contingencies and also allows for better system response during Zone 2 clearing of transmission lines.

The analysis also clearly shows the importance of upgrading the transmission protection system to eliminate the need for Zone 2 clearing of transmission lines. Zone 2 clearing of transmission lines can results in stage 1 and stage 2 UFLS activation during contingencies.

Analysis was completed to determine the impact on the Hawaiian Electric system due to a trip of the AES unit at different load levels. Transfer trip schemes for UFLS activation were utilized in order to mitigate UFLS activation to only stages 1 or stages 1 and 2.

The result of this analysis is shown in Table D-46 for the 2015 load season. The results show the maximum AES output while allowing for either Stage 1 UFLS activation, or Stage 1 and Stage 2 UFLS activation. Reducing the legacy PV amounts from 60 to 40 MW results in an increase in AES output by 20 MW. Utilizing up to Stage 2 UFLS activation allows in an increase in AES output by up to 20 MW for some cases. The max unit dispatch cases (day peak and night minimum) show that benefit to the transmission system to having additional units online for system support, primarily from their added inertia.

Load	Legacy PV	Max AES Trip, with and without UFLS				
		Up To Stage 1		Up To Stage 2		
		Transfer Trip UFLS		Transfer Trip UFLS		
		0	1	0	1	2
day min	40	< 80	< 80	< 80	< 80	< 80
	60	< 80	< 80	< 80	< 80	< 80
day peak	40	<100	<100	120	120	140
	60	<100	<100	100	120	120
day peak, max units	40	140	160	200	200	200
	60	120	140	180	200	200
evening peak	-	160	180	200	200	200
night minimum	-	< 100	< 100	100	100	120
night min, max units	-	120	120	140	140	160
			minimum output not found			

Table D-46. 2015 Maximum AES Output

The result of this analysis is shown in Table D-47 for the 2016 load season. As with the 2015 case results, reducing the legacy PV amounts from 60 to 40 MW results in an increase in AES output by 20 MW. Utilizing up to Stage 2 UFLS activation allows in an increase in AES output by up to 20 MW for some cases. The max unit dispatch cases (day peak and night minimum) show that benefit to the transmission system to having additional units online for system support, primarily from their added inertia.

Comparing the 2015 and 2016 case results also show that utilization of the new unit minimums (down from 24 MW to 10 MW) can allow for an increase in units online, further increasing the system response during under frequency events.

Load	Legacy PV	Max AES Trip, with and without UFLS				
		Up To Stage 1		Up To Stage 2		
		Transfer Trip UFLS		Transfer Trip UFLS		
		0	1	0	1	2
day min	40	< 80	< 80	80	80	80
	60	< 80	< 80	< 80	< 80	80
day peak	40	<100	100	140	140	140
	60	<100	100	120	120	140
day peak, max units	40	100	120	160	160	180
	60	<100	100	140	160	160
evening peak	-	160	180	200	200	200
night minimum	-	< 100	< 100	100	120	120
night min, max units	-	120	140	160	180	180
			minimum output not found			

Table D-47. 2016 Maximum AES Output

The following recommendations are based on the analysis and results of the study:

- Upgrade transmission system protection to eliminate need for Zone 2 clearing of transmission lines.
- Reduce the amount of legacy PV installed on the system by changing over to extended PV settings.
- Incorporate the ability to reduce the minimum output limits of generators.
- Dispatch additional units as possible as needed to mitigate UFLS activation for expected contingencies.
- Utilize a transfer – trip scheme that will activate stages of UFLS for outages of AES.

2017+ Cases

EPS has completed analysis for the Hawaiian Electric system defining the boundary conditions as to the operations of the system for the 2017, 2022, and 2030 case years. The boundary conditions represent the likely operating requirements due to the large additions of renewable energy and changes in load expected in the future.

To aid in clarifying the different results, security tables were created showing the operating requirements for each year and each configuration within that year.

The security tables include data values as to the minimum number for thermal units required, the ramp rate requirements, the regulation requirements, contingency and 30-minute reserves, and required voltage support.

The ramp rate requirement was assumed to be 10% per minute for both PV and wind energy resources. This value was derived from analysis EPS has completed that is not part of this report.

The regulation requirements include values for day time and night time periods. The daytime regulation reserve is calculated as the summation of 20% of the installed DG PV, 35% of installed station PV, and 50% of the installed wind. The night time regulation reserve is calculated as only 50% of the installed wind.

The contingency reserve is calculated as the amount of reserves (energy storage and/or PV regulation) required in order to meet criteria for the largest unit or wind generation facility outage. The 30-minute reserves are equal to the largest unit or wind generation facility outage and is the required amount of energy to be brought online to displace the short term contingency reserves.

2017 Security Tables

The security tables for the 2017 time frame include tables for a 200 MW and 100 MW AES trip. The 2017 cases require a minimum of 4 thermal units online. The day time regulation reserves are 210 MW, with night time reserves of 62 MW, and a ramp rate requirement of 86.6 MW per min. Contingency and 30-minute reserves are 200 MW of the 200 MW AES trip case and 100 MW each for the 100 MW AES trip case. The security tables for the two cases are shown in Table D-48 and Table D-49, respectively.

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	4	86.6 MW / Min	281 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	200 MW	200 MW	+/- 80 MVAr
	DG	471							
Wind		123							
Largest Unit		200							

Table D-48. 2017 Security Table: 200 MW AES Trip

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	4	86.6 MW / Min	281 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	471							
Wind		123							
Largest Unit		100							

Table D-49. 2017 Security Table: 100 MW AES Trip

2022 Security Tables

The security tables for the 2022 time frame include tables for a 100 MW AES trip utilizing additional generation support from either LM6000 units or LMS100 units. The 2022 cases require a minimum of 3 thermal units utilizing LM6000s and only 2 thermal units utilizing LMS100s. The day time regulation reserves are 227 MW, with night time reserves of 62 MW, and a ramp rate requirement of 95.1 MW per min. Contingency and 30-minute reserves are 100 MW for each case. The security tables for the two cases are shown in Table D-50 and Table D-52, respectively.

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	3 AES + 2 LM6000	95.1 MW / Min	311 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	556							
Wind		123							
Largest Unit		100							

Table D-50. 2022 Security Table: AES + LM6000 Units

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	2 AES + 1 LMS100	95.1 MW / Min	311 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	556							
Wind		123							
Largest Unit		100							

Table D-51. 2022 Security Table: AES + LMS100 Units

2030 Security Tables

The security tables for the 2030 time frame include tables for cases utilizing generation support from either LM6000 units or LMS100 units. The 2030 cases require a minimum of 3 LM6000s or only 2 LMS100s. The day time regulation reserves are 242 MW, with night time reserves of 62 MW, and a ramp rate requirement of 102.6 MW per min. Contingency and 30-minute reserves are 100 MW for each case. The security tables for the two cases are shown in Table D-52 and Table D-53, respectively.

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	7	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	60 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-52. 2030 LM6000 Units

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	5	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	60 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-53. 2030 LMS100 Units

The security tables were also created for the 2030 cases assuming only the 60 MW ESS is available for contingency reserves. Utilizing only the 60 MW ESS requires a minimum of 7 LM6000s or 5 LMS100s. The day time regulation reserves are 242 MW, with night time reserves of 62 MW, and a ramp rate requirement of 102.6 MW per min. Contingency reserves are 60 MW and 30-minute reserves are 100 MW for each case. The security tables for the two cases are shown in Table D-54 and Table D-55, respectively.

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	3	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-54. 2030 MIN LM6000 Units 60 MW BESS

Value		Capacity (MW)	# of Thermal units required	Ramp Rate Requirements	Regulation Reserves - Day time	Regulation Reserves - Night time	Contingency Reserves	30 Minute Reserves	Voltage Support (SVC)
PV Level	Station	272	2	95.1 MW / Min	337 MW (20% of DG PV+ 35% Station PV + 50% Wind)	62 MW (50% of Wind)	100 MW	100 MW	+/- 80 MVAr
	DG	631							
Wind		123							
Largest Unit		100							

Table D-55. 2030 MIN LMS100 Units 60 MW BESS

E. Essential Grid Services

Grid services include generating capacity plus ancillary services, which are both essential to reliable system operation. Generating capacity is used to meet load demands; ancillary services supplement the generating capacity to help meet demand or correct frequency deviations that occur as a result of normal changes in load and generation, as well as the result of abnormal transient events. Ancillary services can occur in layers, with some taking longer to act than others. The system operator needs to designate which ancillary services are necessary for the system characteristics at the time.

Synchronous generation has traditionally provided generating capacity and ancillary services. Increasing amounts of variable generation, however, diminish the amount of dispatchable generation on the system and the ability of dispatchable generation to provide the needed ancillary services. In many cases, the variable generation resources do not provide the level of ancillary services required for the system's security. In addition, the potential loss of variable distributed generation (whether due to large ramping events or trips due to transient events) has become the largest contingency for which many of the ancillary services must be designed.

For these reasons, new generation resources must have the ability to also provide required ancillary services, or new systems that can provide the ancillary services must be added. Variable generation costs should include the cost of periodic testing and maintenance of their accompanying ancillary systems to ensure the reliability of the electric system. The variable generation protection and control devices should be tested and verified at installation, and tested and maintained periodically after that. Every device should be calibrated and tested at least every three years.

GRID SERVICES

Capacity

Capacity is the maximum reliable amount of electrical output available from a resource. Systems must be operated to ensure there is sufficient capacity online to meet demand in the near term. Systems must be planned and designed to ensure that there is adequate supply of capacity to meet future demands. For dispatchable generation, the capacity is the maximum power output of the generating unit[1]. For variable generation (such as wind or solar power), capacity in the near term is the minimum available amount of output expected in the next one to three hours. The capacity of controlled load in the near term is the minimum level of load under control during each of the four six-hour planning periods of a 24-hour day.

For planning capacity margins, the capacity contribution for variable generation is developed by examining the historical availability during the peak demand periods, to determine the amount of capacity which is very probable to be available in the peak period. Similarly, demand response could contribute to capacity if it is available during the peak period. To count as capacity, the generation does not have to be under automatic generation control (AGC) to reach its maximum rating. Unit control can be by AGC, by human intervention, or a combination, so long as the output is controllable and predictable.

Capacity does not have a response time requirement. However, as stated above, it must be reliably available for a period of time.

Generation capacity should be modeled and tested consistent with HI-Mod-0010 and HI-Mod-0025.[2] Controlled load capacity should be modeled and tested in accordance with capacity testing and modeling requirements for conventional generation capacity. Controlled load will need periodic review and exercising to confirm its stated capacity, as the load characteristics change over time.

1 Generators are designed higher than its prime mover's capability, therefore the generator's nameplate rating can sometimes be higher than what it actually produces.

2 HI-Mod-0010 is the proposed Hawaiian standard for modeling unit capacity used for system studies. HI-Mod-0025 is the proposed Hawaiian standard for testing unit capacity to confirm its model for use in electrical studies.

ANCILLARY SERVICES

Regulating Reserve

Regulating reserve is the amount of unloaded capacity of regulation resources that can be used to match system demand with generation resources and maintain normal frequency. Use of regulating reserve is governed by a command from Automatic Generation Control (AGC) to a change in system demand. A change in system demand results in a change in system frequency, and the AGC program will adjust the generating units under its control to return system frequency to the normal state. A regulation resource is a resource that immediately responds, without delay, to commands from AGC to predictably increase or decrease its generation output. Regulation resources must accurately and predictably respond to AGC commands throughout their range of operation.

Regulation resources can also include non-traditional resources such as controlled loads or storage, providing the necessary control capabilities and response for the AGC interface. Non-generation resources participating in regulation must be capable of sustaining the maximum increase or decrease for at least 30 minutes.

Regulating reserve is used to counter normal changes in load or variable generation. Changes in generation output or controlled loads must be completed within 2 seconds of the AGC command, and must be controllable by AGC to a resolution of 0.1 MW.

In our islanded power system, regulation resources are constantly used to balance load and generation to maintain a 60 Hz frequency reference. The number of controls to regulating resources is greater than larger systems, due to a combination of the impacts of the small system size, its isolation, and the amount of variable wind and solar generation on the systems whose variable output requires additional adjustments from regulating resources. As a result, it has been typical on the island systems that all online resources capable of participating in regulation are used for regulation.

If demand response or storage are used for regulation, the cost of modifying the AGC system to be able to utilize these non-traditional resources as a regulation resource should be included in valuation of these alternate resources. The implementation must include special considerations specific to non-generation resources, such as the need to adopt the regulation algorithms to consider that the limits of the storage or demand response (that is, the response cannot be sustained indefinitely, unlike a dispatchable generator), and to include the rotation of DR within the group to limit impact on DR resources of the same type.

Contingency Reserve

Each of the Companies' systems must be operated such that the system remains operable and the grid frequency can be quickly restored following a contingency situation wherein a generating or transmission resource on the island suddenly trips offline. This can be the largest single unit, the largest combination of dependent units (such as combined cycle units), or the loss of a single transmission line connecting a large generation unit to the system. The contingency reserve is the reserve designated by a system operator to meet these requirements.

Conventional generation, stored energy resources, curtailed variable generation, load shed or DR resources can provide contingency reserves.

Contingency reserves carried on generator resources, including storage, must respond automatically to changes in the system frequency, with a droop response determined by the system operator.

The island systems are unique in that all imbalances between supply and demand result in a change in system frequency. There are no interconnections to draw additional power from in the event of loss of generation. As a result, the island systems rely heavily upon instantaneous underfrequency load-shed to provide protection reserves and contingency reserves. If participating in the instantaneous protection, which may be used for contingency reserves or system protection, DR or load shed must be accurate to ± 0.02 Hz and ± 0.0167 cycles. The response time from frequency trigger to load removal can be no more than 7 cycles.

DR that cannot meet the 7-cycle requirement may be used for a time-delay, or the "kicker block" of under frequency load-shed. This block of load-shed is used for smaller increments of generation loss than the contingency reserves (set at a higher frequency set-point than the faster, instantaneous load-shed). Resources deployed for time-delay load-shed must be controllable within an accuracy of ± 0.02 Hz and ± 0.02 seconds, and have a response time from frequency trigger to load removal adjustable in increments of 0.5 seconds up to 30 seconds, to be considered for use as time delay load-shed.

To ensure consistent performance, DR controls and loads used for contingency reserve should be tested and certified annually. (See HI-Mod-012, HI-Mod-010, and HI-Mod-025, 26, 27.[3]) Annual costs for testing and certification should be included in the total cost for these provisions.

[3] HI-Mod-0012 is the proposed Hawaiian standard for modeling and reporting the dynamic response of system models and results of simulations using these models. HI-Mod-0260 is the proposed Hawaiian standard for verifying plant or excitation equipment used in system models. HI-MOD-0027 is the proposed Hawaiian standard for verifying the models for turbine/governor and frequency control functions.

Controllable load used in any other DR program cannot be included in the loads designated as contingency reserves. The impacts of any DR use on the instantaneous underfrequency load-shed schemes must be evaluated and incorporated into the design to ensure adequate system protection remains.

10-Minute Reserve

Off-line, quick-start resources can be used as 10-minute reserves provided they can be started and synchronized to the grid in 10 minutes or less. These resources may be used for restoring regulation or contingency reserves.

When conditions warrant, a system operator starts the 10-minute reserve resource remotely, and automatically synchronizes it to the power system. The system operator then either loads the resource to a predetermined level, or places it under AGC control, either of which must be completed within 10 minutes. The 10-minute reserve must be able to provide the declared output capability for a minimum of two hours.

The resource can be any resource with a known output capability. Resources can include generators, storage, and controllable loads. A system operator must be able to control these resources to restore regulation or contingency reserves.

30-Minute Reserve

Off-line, 30-minute reserve resources shall be resources that can be operated during normal load and generation conditions, and can be started and synchronized to the grid in 30 minutes or less. They can be counted as capacity resources to meet expected load and demand, or to restore contingency reserves.

When conditions warrant, a system operator starts the resource remotely, synchronizes it, and (if participating in regulating reserves) places it under AGC control within 30 minutes; when it must then be able to serve the capacity for at least three hours.

The 30-minute reserve resource can be any resource with a known capacity. A system operator must be able to control these load resources to restore contingency or regulation reserves.

Long Lead-Time Reserve

Resources that take longer than 30 minutes to be started, synchronized, and placed under AGC control (if participating in regulating reserves) are considered long lead-time reserves. They can be operated during normal load and generation conditions. These resources may be used as capacity resources to meet expected load and demand, and for restoring contingency reserves.

Long lead-time reserves can include any resource with a known capacity. System operators must be able to control these load resources to restore contingency reserves.

Long-lead time resources can be used to meet forecast peak demand, in addition to restoring contingency reserves or the replacement of fast-start reserves. Long-lead time reserves must be able to serve the capacity for at least three hours.

Black Start Resource

A black start resource is a generating unit and its associated equipment that can be started without support from the power system, or is designed to remain energized without connection to the remainder of the power system. A black start resource needs to be able to energize a bus, meeting a system operator's restoration plan needs for real and reactive power capability, frequency, and voltage control. It must also be included in the transmission operator's restoration plan.

A black start resource must be capable of starting within 10 minutes. The starting sequence can be manual or automatic.

Primary Frequency Response

Primary frequency response is a generation resource's automatic response to an increase or decrease in frequency. The primary frequency response is the result of governor control, not control by AGC or frequency triggers, and must be sustainable. Unless controlled by a governor or droop response device, controlled load cannot provide primary frequency control.

The resource must immediately alter its output in direct proportion to the change in frequency, to counter the change in frequency. The response is determined by the design setting, which is specified by the system operator as a droop response from 1 to 5 percent. The response must be measurable within 10 seconds of the change in frequency. Under certain conditions, a certain generator resource may be placed on zero droop (also called isochronous control), such as under disturbance and restoration. Under these conditions, the isochronous generator will control system frequency instead of AGC.

Primary frequency response of a device is subject to the limitations of equipment. Equipment that is at its maximum operating output is not able to increase output in response to low frequency, but will still decrease its output in response to increasing frequency. Any generator at its maximum output, or a variable wind generator producing the maximum output for the available wind energy, may, if designed to have a frequency response, provide downward response to high frequency, but will not be able to increase output in response to low frequency. Curtailed variable generation or conventional generation operating below its maximum limit and above its minimum limit can contribute both upward and downward primary frequency response. Based on the design of its system, energy storage systems can also provide primary frequency response.

Primary frequency response cannot be withdrawn if frequency is within the bandwidth of a reportable disturbance as defined in BAL-HI-002. The primary frequency response should replace the inertia or fast frequency response of the system without a drop in system frequency.

Inertial or Fast Frequency Response

Inertial or fast frequency response is a local response to a change in frequency, reducing its rate of change. The response is immediate (measured in milliseconds), continuous, and proportional to the change in frequency, and does not rely on governor controls. The response is available even if the resource is also being used for other services (such as regulation or ramping). This response is short-lived, lasting not more than two to three seconds.

Inertial response relies on the rotating mass of a conventional generator. It can also be supplied by flywheels. Fast frequency response can be supplied by battery storage. If the inertia or fast response reserves are supplied from a resource that cannot sustain the load, primary or secondary resources must be available to take over without a drop in system frequency.

Secondary Frequency Control

Secondary (or supplemental) frequency control is provided by resources in response to AGC to correct a change in frequency, using both the regulating and contingency reserves. Secondary frequency response can be provided by conventional generation, load control, or variable generation, all of which must be under AGC control. If AGC is disabled, such as during system restoration, secondary frequency control will be provided by manual operation of resources to maintain the isochronous generator within its lower and upper limits. The response requirements for secondary control are the same as for participation in regulating reserves.

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F. Modeling Assumptions Data

The Hawaiian Electric Companies created this PSIP based, in parts, on a realization of the current state of the electric systems in Hawaiʻi, forecast conditions, and reasonable assumptions regarding technology readiness, availability, performance, applicability, and costs. As a result, this plan presents a reasonable and viable path into the future for the evolution of our power systems. We have attempted to document and be fully transparent about the assumptions and methodologies utilized to develop this plan. We recognize, however, that over time these forecasts and assumptions may or may not prove to be accurate or representative, and that the plan would need to be updated to reflect changes. As we move forward, we will continually evaluate the impacts of any changes to our material assumptions, seek to improve the planning methodologies, and evaluate and revise the plan to best meet the needs of our customers.

This appendix summarizes the assumptions utilized to perform the PSIP analyses.

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UTILITY COST OF CAPITAL AND FINANCIAL ASSUMPTIONS

The Hawaiian Electric Companies finance their investments through two main sources of capital: debt (borrowed money) or equity (invested money). In both cases, we pay a certain rate of return for the use of this money. This rate of return is our *Cost of Capital*.

Table F-1 lists the various sources of capital, their weight (percent of the entire capital portfolio), and their individual rates of return. Composite percentages for costs of capital are presented under the table.

Capital Source	Weight	Rate
Short Term Debt	3.0%	4.0%
Long Term Debt (Taxable Debt)	39.0%	7.0%
Hybrids	0.0%	6.5%
Preferred Stock	1.0%	6.5%
Common Stock	57.0%	11.0%

Composite Weighted Average 9.185%
After-Tax Composite Weighted Average 8.076%

Table F-1. Utility Cost of Capital

FUEL SUPPLY AND PRICES FORECASTS

The potential cost of producing electricity will depend, in part, on the cost of fuels utilized in the generation of power. The cost of different fuels over the next 20-plus years are forecast and used in the PSIP analyses. The Companies burn the following different types of fuels:

- *No.2 Diesel Oil*
- *Low Sulfur Fuel Oil (LSFO)*. A residual fuel oil similar to No. 6 fuel oil that contains less than 5,000 parts per million of sulfur; about 0.5% sulfur content.
- *Ultra Low Sulfur Diesel (ULSD)*
- *Biodiesel*
- *Liquefied Natural Gas (LNG)* is a natural gas (a fossil fuel) that has been converted to a liquid, which sharply decreases volume and eases transportation and storage.

How the Fuel Price Forecasts Were Derived

Petroleum-Based Diesel Fuels

In general, we derived petroleum-based diesel fuels forecasts by applying the relationship between historical crude oil commodity prices and historical fuel purchase prices to forecasts for the crude oil commodity price. The petroleum-based fuel forecasts reflect U.S. Energy Information Administration (EIA) forecast data for *Imported Crude Oil* and *GDP Chain-Type Price Index* from the 2014 Annual Energy Outlook (AEO2014) year-by-year tables. Historical prices for crude oil are EIA publication table data for the *Monthly Energy Review* and macroeconomic data. Historical actual fuel costs incorporate taxes and certain fuel-related and fuel-handling costs including but not limited to trucking and ocean transport, petroleum inspection, and terminalling fees.

It may be necessary to utilize a fuel blend of LSFO and diesel oil (that is, 60% LSFO and 40% diesel) for purposes of environmental compliance.

Biodiesel

Biodiesel forecasts are generally derived by comparing commodity forecasts with recent biofuel contracts and RFP bids to determine adjustments needed to derive each company's respective biodiesel price forecast from forecasted commodities. EIA provides low, reference, and high petroleum forecasts, which are used to project low, reference, and high petroleum-based fuel price forecasts. A similar commodity forecast has not been found for biodiesel, although EIA might provide one in the future. In lieu of such a source, we used the Food and Agricultural Policy Research Institute at Iowa State University (FAPRI) to create a reference forecast, which we then scaled on the EIA Petroleum forecasts to create a low and high biodiesel forecast.

Liquefied Natural Gas (LNG)

We do not have historical purchase data for LNG in Hawaiʻi. For purposes of this PSIP analyses, LNG pricing (delivered to the power generation facilities) were developed as described in Appendix I: LNG to Hawaiʻi.

Hawaiian Electric Fuel Price Forecasts

$/MMBtu	Fuel Price Forecasts					
Year	*No.2 Diesel*	*LSFO*	*ULSD*	*40% Diesel/ 60% LSFO Blend*	*Biodiesel*	*LNG*
2014	$20.98	$18.27	$22.16	$19.32	$33.01	n/a
2015	$20.97	$18.23	$22.16	$19.29	$29.64	n/a
2016	$20.57	$17.81	$21.77	$18.88	$29.81	n/a
2017	$20.56	$17.76	$21.76	$18.84	$30.54	$15.71
2018	$21.01	$18.16	$22.23	$19.26	$31.21	$15.81
2019	$21.71	$18.82	$22.97	$19.94	$31.24	$16.00
2020	$22.51	$19.56	$23.79	$20.70	$31.30	$16.30
2021	$23.40	$20.39	$24.72	$21.55	$31.54	$16.69
2022	$24.33	$21.25	$25.68	$22.44	$31.92	$12.73
2023	$25.32	$22.18	$26.70	$23.39	$32.05	$12.95
2024	$26.30	$23.09	$27.72	$24.33	$32.54	$13.12
2025	$27.27	$23.99	$28.73	$25.26	$32.84	$13.33
2026	$28.18	$24.84	$29.68	$26.13	$33.14	$13.61
2027	$29.24	$25.82	$30.77	$27.14	$33.44	$14.02
2028	$30.23	$26.74	$31.79	$28.08	$33.74	$14.39
2029	$31.27	$27.70	$32.88	$29.08	$34.04	$14.78
2030	$32.26	$28.62	$33.91	$30.02	$34.34	$15.21

Table F-2. Fuel Price Forecasts

SALES AND PEAK FORECASTS

Sales and net peak forecasts were developed with and without the effects of Dynamic Pricing. As described in the *Integrated Demand Response Portfolio Plan (IDRPP)*[1] Dynamic Pricing is a demand response program that incent customers (on a voluntary basis) to change their energy use behavior, resulting is increased load demand during certain periods of the day and decreased net peak demand.

Sales Forecasts (without Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	7,697.6	7,332.5	494.2	470.7	6,861.8
2016	7,831.1	7,459.7	571.6	544.4	6,915.2
2017	7,959.4	7,581.9	622.5	593.0	6,988.9
2018	8,002.1	7,622.5	655.9	624.8	6,997.7
2019	8,028.6	7,647.8	688.5	655.9	6,992.0
2020	8,048.3	7,666.6	725.1	690.7	6,975.9
2021	8,031.6	7,650.7	752.3	716.6	6,934.1
2022	8,010.7	7,630.8	782.6	745.5	6,885.3
2023	7,974.4	7,596.2	813.4	774.8	6,821.4
2024	7,917.0	7,541.5	846.8	806.7	6,734.8
2025	7,785.9	7,416.6	874.8	833.4	6,583.2
2026	7,584.6	7,224.9	904.9	862.0	6,362.9
2027	7,380.5	7,030.5	934.2	889.9	6,140.6
2028	7,176.4	6,836.1	965.4	919.6	5,916.5
2029	6,972.3	6,641.6	990.2	943.2	5,698.4
2030	6,768.2	6,447.2	1,016.6	968.3	5,478.9

Loss Factor: 4.743%

Table F-3. Sales Forecasts (without Dynamic Pricing Adjustments)

[1] The IDRPP was filed on July 28, 2014.

Sales Forecasts (with Dynamic Pricing Adjustments)

Year	Load without DG PV		Total DG PV (Uncurtailed)		Sales with DG PV
	Net Generation: GWh (a)	*Sales: Customer GWh (b)*	*Net GWh (c)*	*Customer GWh (d)*	*Customer GWh (b – d)*
2015	7,697.6	7,332.5	494.2	470.7	6,861.8
2016	7,829.8	7,458.4	571.6	544.4	6,914.0
2017	7,930.7	7,554.5	622.5	593.0	6,961.5
2018	7,973.5	7,595.3	655.9	624.8	6,970.5
2019	8,000.4	7,621.0	688.5	655.9	6,965.1
2020	8,020.3	7,639.9	725.1	690.7	6,949.2
2021	8,003.9	7,624.3	752.3	716.6	6,907.7
2022	7,983.6	7,604.9	782.6	745.5	6,859.4
2023	7,947.5	7,570.5	813.4	774.8	6,795.7
2024	7,889.9	7,515.7	846.8	806.7	6,709.0
2025	7,759.6	7,391.6	874.8	833.4	6,558.2
2026	7,559.4	7,200.8	904.9	862.0	6,338.9
2027	7,356.3	7,007.4	934.2	889.9	6,117.5
2028	7,153.4	6,814.1	965.4	919.6	5,894.6
2029	6,950.1	6,620.4	990.2	943.2	5,677.2
2030	6,747.1	6,427.1	1,016.6	968.3	5,458.7

Table F-4. Sales Forecasts (with Dynamic Pricing Adjustments)

Net Peak Forecasts

Year	Net Peak w/o Dynamic Pricing			Net Peak w/ Dynamic Pricing		
	Net Day Peak (w/o DG-PV)	Net Evening Peak (w/o DG-PV)	Total DG-PV	Net Day Peak (w/o DG-PV)	Net Evening Peak (w/o DG-PV)	Total DG-PV
	MW	MW	MW	MW	MW	MW
2015	1,187.0	1,195.0	325.7	1,187.0	1,195.0	325.7
2016	1,196.0	1,203.0	375.6	1,196.0	1,199.0	375.6
2017	1,215.0	1,223.0	410.3	1,223.0	1,137.0	410.3
2018	1,220.0	1,228.0	432.3	1,229.0	1,142.0	432.3
2019	1,230.0	1,238.0	453.8	1,238.0	1,151.0	453.8
2020	1,230.0	1,238.0	476.5	1,239.0	1,151.0	476.5
2021	1,220.0	1,227.0	495.8	1,230.0	1,141.0	495.8
2022	1,207.0	1,213.0	515.8	1,223.0	1,128.0	515.8
2023	1,194.0	1,200.0	536.1	1,203.0	1,117.0	536.1
2024	1,186.0	1,193.0	556.5	1,195.0	1,109.0	556.5
2025	1,154.0	1,160.0	576.6	1,165.0	1,082.0	576.6
2026	1,109.0	1,113.0	596.4	1,120.0	1,045.0	596.4
2027	1,063.0	1,066.0	615.7	1,075.0	1,009.0	615.7
2028	1,017.0	1,019.0	634.4	1,030.0	970.2	634.4
2029	970.7	972.0	652.6	983.9	931.1	652.6
2030	932.4	932.4	670.0	948.3	903.4	670.0

Table F-5. Net Peak Forecasts

DEMAND RESPONSE

Demand Response Programs

The *Integrated Demand Response Portfolio Plan*[2] introduced seven categories of programs.

Residential and Small Business Direct Load Control Program (RBDLC). This new RBDLC program continues and expands upon the existing RDLC and Small Business Direct Load Control (SBDLC) programs. RBDLC enables new and existing single-family, multi-family, and master metered residential customers, in addition to small businesses, to participate in an interruptible load program for electric water heaters, air conditioning, and other specific end uses.

Residential and Small Business Flexible Program. This new program enables residential and small business customers with targeted devices (such as controllable grid-interactive water heaters) to meet ancillary service requirements by providing adjustable load control and thermal energy storage features over various timeframes.

Commercial & Industrial Direct Load Control Program (CIDLC). The updated CIDLC program allows commercial and industrial customers to help shift load, usually during peak periods, by allowing their central air conditioning, electric water heaters, and other applicable appliances to be remotely cycled or disconnected.

Commercial & Industrial Flexible Program. This new program enables commercial and industrial customers with targeted devices (such as air conditioning, ventilation, refrigeration, water heating, and lighting) to meet ancillary service requirements by providing adjustable load control and/or thermal energy storage features over differing timeframes.

Commercial & Industrial Pumping Program. The Commercial & Industrial Pumping program enables county and privately owned water facilities with pumping loads and water storage capabilities to be dynamically controlled. This will be accomplished by using variable frequency drives and emergency standby generation to adjust power demand and supply at the water facilities, and better balance supply and demand of power system loads.

Customer Firm Generation Program. Commercial and industrial customers who participate in this program allow system operators to dispatch their on-site standby generators to help meet power system load demand. Monitoring equipment on the

[2] *ibid.*

standby generators tracks the usage of program participation, testing, and assures environmental permit compliance.

Dynamic & Critical Peak Pricing program. This program enables load shifting to "smooth" the daily system load profiles based on demand and price.

Cost of DR Programs

Several grid services foretell the cost of the demand response programs. The avoided cost for a grid service is the cost of an alternative resource (energy storage or a generator) providing the equivalent service. Avoided cost could be based on several factors, including installed capacity costs, fuel costs, and cost of alternatives, each of which depends on the current state of the system. Potential avoided cost calculations include:

Capacity: The cost of new capacity deferral.

Regulating Reserve: The cost of a frequency support energy storage device, or the savings from reduced regulating reserve requirements, as calculated using a production cost model.

Contingency Reserve:. For O'ahu, the fuel cost savings resulting from a reduction in the contingency reserve requirement from thermal generation commensurate with the DR resources assumed to meet the contingency reserve requirements, as calculated using a production cost model. For Maui and Hawai'i, this would offset under-frequency load shedding, which potentially provides a customer benefit but not a readily evaluated economic benefit.

Non-AGC Ramping: The fuel cost and maintenance savings resulting from deferring the start of units to compensate for variable energy down ramps.

Non-Spinning Reserve: The cost of maintaining existing resources that currently meet non-spinning reserves (small diesel units).

Advanced Energy Delivery: The production cost savings incurred by shifting demand, as compared to production costs if demand were not shifted.

All of the above avoided costs are offset by the program costs and reduced sales. Where a resource or program can meet two or more grid service requirements, although not simultaneously, the avoided cost is determined by the most economic use. The maximum price paid for a DR program would be the difference between the avoided cost and the program's operational cost. At the maximum price, the overall rate impact to customers would be economically neutral.

DR Grid Service Requirements and MW Benefits

Grid Service	Residential and Small Business Direct Load Control[3]				Residential and Small Business Flexible	
	Capacity	*Contingency Reserve*	*Non-AGC Ramping*	*Non-Spinning Reserve*	*Regulating Reserve*	*Accelerated Energy Delivery*
Frequency	Unlimited	Unlimited	Unlimited	Unlimited	Continuous	Continuous
Event Length	1 hour	1 hour	1 hour	1 hour	Minutes	Minutes
Event Cost	None	None	None	None	None	None
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	16.0	0.0	16.0	16.0	0.0	0.0
2015	18.9	0.0	18.9	18.9	0.6	0.3
2016	21.8	0.0	21.8	21.8	1.3	0.7
2017	24.7	0.0	24.7	24.7	1.9	1.0
2018	27.5	0.0	27.5	27.5	2.6	1.4
2019	30.4	0.0	30.4	30.4	3.3	1.7
2020	33.3	0.0	33.3	33.3	3.9	2.1
2021	33.3	0.0	33.3	33.3	4.5	2.4
2022	33.3	0.0	33.3	33.3	5.1	2.7
2023	33.3	0.0	33.3	33.3	5.1	2.7
2024	33.3	0.0	33.3	33.3	5.1	2.7
2025	33.3	0.0	33.3	33.3	5.1	2.7
2026	33.3	0.0	33.3	33.3	5.1	2.7
2027	33.3	0.0	33.3	33.3	5.1	2.7
2028	33.3	0.0	33.3	33.3	5.1	2.7
2029	33.3	0.0	33.3	33.3	5.1	2.7
2030	33.3	0.0	33.3	33.3	5.1	2.7

Table F-6. Demand Response Program Grid Service Requirements and MW Benefits (1 of 2)

[3] The 2014 figure of 16.0 MW is the long standing planning assumption derived from the per device assumptions in the 2011 EnergyScout Impact Evaluation study. The IDRPP filed on July 28 reflects a lower figure of 10 MW, based on the average curtailment results from 2013 events conducted during evening peak hours."

Grid Service	Commercial & Industrial Direct Load Control		Commercial & Industrial Flexible		Commercial & Industrial Pumping		Customer Firm Generation
	Capacity	*Contingency Reserve*	*Regulating Reserve*	*Non-AGC Ramping*	*Regulating Reserve*	*Non-AGC Ramping*	*Capacity*
Frequency	300 hours per year	300 hours per year	Continuous	Continuous	Continuous	Continuous	100 hours per year
Event Length	4 hours maximum	4 hours maximum	Minutes	Minutes	Minutes	Minutes	4 hours maximum
Event Cost	50¢/kWh	50¢/kWh	None	None	None	None	50¢/kWh
Year	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2014	16.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	17.6	0.0	0.5	1.7	0.2	0.2	0.0
2016	19.1	0.0	1.0	3.5	0.5	0.5	5.0
2017	20.7	0.0	1.6	5.3	0.7	0.7	5.0
2018	22.3	0.0	2.1	7.1	0.9	0.9	5.0
2019	23.8	0.0	2.6	9.0	1.2	1.2	5.0
2020	25.4	0.0	3.2	10.8	1.4	1.4	5.0
2021	25.4	0.0	3.7	12.5	1.7	1.7	5.0
2022	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2023	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2024	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2025	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2026	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2027	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2028	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2029	25.4	0.0	4.1	14.1	1.9	1.9	5.0
2030	25.4	0.0	4.1	14.1	1.9	1.9	5.0

Table F-7. Demand Response Program Grid Service Requirements and MW Benefits (2 of 2)

RESOURCE CAPITAL COSTS[4]

Table F-9 through Table F-16 show the calculations to arrive at the capital cost for various resources used in the PSIP modeling analyses. The overall cost escalation rate used in our analyses is 1.83%.

Table Legend

Column Heading	Explanation
NREL Capital Cost, 2009 $, $/kW	The starting basis for capital costs used in the analyses unless noted otherwise
B&V Hawai'i Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (<100 MW)
BCG Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the ICE (>100 MW)
EIA Capital Cost, 2009 $, $/kW	The starting basis for capital cost of the Waste-to-Energy resource
Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource from 2009 dollars up to the year of installation
EIA Adjustment Factor	A location specific cost adjustment factor for Hawai'i
Utility Adjustment Factor	A technology specific cost adjustment factor
Adjusted Capital Cost, Nominal $, $/kW	An escalated capital cost of the resource that reflects any cost adjustment factors
NREL Fixed O&M, 2009 $, $/kW-year	The starting basis for fixed O&M used in the analyses
Fixed O&M, Nominal $, $/kW	An escalated fixed O&M cost of the resource from 2009 dollars up to the year of installation
NREL Variable O&M, 2009 $, $/MWh	The starting basis for variable O&M used in the analyses
Variable O&M, Nominal $, $/MWh	An escalated variable O&M cost of the resource from 2009 dollars up to the year of installation

Table F-8. Resource Capital Cost Table Legend

[4] Calculations were based on *Cost and Performance Data for Power Generation Technologies*, prepared for the National Renewable Energy Laboratory (NREL), Black & Veatch, February 2012.

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Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.46	$1,608.29	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.46	$1,761.36	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.46	$1,928.99	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.46	$2,112.58	$5.26	$7.71	$29.90	$43.80

Table F-9. Simple Cycle Large (40–100 MW) Aeroderivative Combustion Turbine

Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$651.00	$726.04	51.5%	1.77	$1,945.73	$5.26	$5.87	$29.90	$33.35
2020	$651.00	$795.14	51.5%	1.77	$2,130.91	$5.26	$6.42	$29.90	$36.52
2025	$651.00	$870.81	51.5%	1.77	$2,333.71	$5.26	$7.04	$29.90	$40.00
2030	$651.00	$953.69	51.5%	1.77	$2,555.82	$5.26	$7.71	$29.90	$43.80

Table F-10. Simple Cycle Small (<40 MW) Aeroderivative Combustion Turbine

Internal Combustion (<100 MW) Engine

Year Installed	B&V Hawai'i Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,810.00	$2,967.54	0.0%	1.00	$2,967.54	$10.14	$11.31	$11.74	$13.09
2020	$2,810.00	$3,249.96	0.0%	1.00	$3,249.96	$10.14	$12.39	$11.74	$14.34
2025	$2,810.00	$3,559.27	0.0%	1.00	$3,559.27	$10.14	$13.56	$11.74	$15.70
2030	$2,810.00	$3,898.02	0.0%	1.00	$3,898.02	$10.14	$14.85	$11.74	$17.20

Table F-11. Internal Combustion (<100 MW) Engine

Internal Combustion (>100 MW) Engine

Year Installed	BCG Capital Cost, 2012 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,352.00	$1,427.80	0.0%	1.20	$1,713.36	$10.14	$11.31	$11.74	$13.09
2020	$1,352.00	$1,563.68	0.0%	1.20	$1,876.42	$10.14	$12.39	$11.74	$14.34
2025	$1,352.00	$1,712.50	0.0%	1.20	$2,055.01	$10.14	$13.56	$11.74	$15.70
2030	$1,352.00	$1,875.49	0.0%	1.20	$2,250.59	$10.14	$14.85	$11.74	$17.20

Table F-12. Internal Combustion (>100 MW) Engine

Residential Photovoltaics

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$4,340.00	$4,840.26	0.0%	1.00	$4,840.26	$48.00	$53.53	$0.00	$0.00
2020	$3,750.00	$4,580.29	0.0%	1.00	$4,580.29	$45.00	$54.96	$0.00	$0.00
2025	$3,460.00	$4,628.29	0.0%	1.00	$4,628.29	$43.00	$57.52	$0.00	$0.00
2030	$3,290.00	$4,819.74	0.0%	1.00	$4,819.74	$41.00	$60.06	$0.00	$0.00

Table F-13. Residential Photovoltaics

Utility Scale Photovoltaics (Fixed Tilt)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$2,550.00	$2,843.93	0.0%	0.75	$2,132.95	$48.00	$53.53	$0.00	$0.00
2020	$2,410.00	$2,943.60	0.0%	0.75	$2,207.70	$45.00	$54.96	$0.00	$0.00
2025	$2,280.00	$3,049.86	0.0%	0.75	$2,287.39	$43.00	$57.52	$0.00	$0.00
2030	$2,180.00	$3,193.62	0.0%	0.75	$2,395.22	$41.00	$60.06	$0.00	$0.00

Table F-14. Utility Scale Photovoltaics (Fixed Tilt)

Geothermal, Non-Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$5,940.00	$6,624.69	27.2%	1.00	$8,426.61	$36.00	$40.15	$31.00	$34.57
2020	$5,940.00	$7,255.18	27.2%	1.00	$9,228.59	$36.00	$43.97	$31.00	$37.86
2025	$5,940.00	$7,945.68	27.2%	1.00	$10,106.91	$36.00	$48.16	$31.00	$41.47
2030	$5,940.00	$8,701.89	27.2%	1.00	$11,068.81	$36.00	$52.74	$31.00	$45.41

Table F-15. Geothermal, Non-Dispatchable

Geothermal, Fully Dispatchable

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$6,065.00	$6,764.10	27.2%	1.00	$8,603.94	$36.00	$40.15	$31.00	$34.57
2020	$6,065.00	$7,407.86	27.2%	1.00	$9,422.80	$36.00	$43.97	$31.00	$37.86
2025	$6,065.00	$8,112.89	27.2%	1.00	$10,319.59	$36.00	$48.16	$31.00	$41.47
2030	$6,065.00	$8,885.02	27.2%	1.00	$11,301.74	$36.00	$52.74	$31.00	$45.41

Table F-16. Geothermal, Fully Dispatchable

Combined Cycle Turbine

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,230.00	$1,371.78	53.1%	1.21	$2,533.86	$6.31	$7.04	$3.67	$4.09
2020	$1,230.00	$1,502.34	53.1%	1.21	$2,775.02	$6.31	$7.71	$3.67	$4.48
2025	$1,230.00	$1,645.32	53.1%	1.21	$3,039.13	$6.31	$8.44	$3.67	$4.91
2030	$1,230.00	$1,801.91	53.1%	1.21	$3,328.37	$6.31	$9.24	$3.67	$5.38

Table F-17. Combined Cycle Turbine

Run-of-River Hydroelectric

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,500.00	$3,903.44	19.1%	1.35	$6,276.14	$15.00	$16.73	$24.00	$26.77
2020	$3,500.00	$4,274.94	19.1%	1.35	$6,873.46	$15.00	$18.32	$24.00	$29.31
2025	$3,500.00	$4,681.80	19.1%	1.35	$7,527.63	$15.00	$20.06	$24.00	$32.10
2030	$3,500.00	$5,127.38	19.1%	1.35	$8,244.06	$15.00	$21.97	$24.00	$35.16

Table F-18. Run-of-River Hydroelectric

Wind, Onshore

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$1,980.00	$2,208.23	30.1%	1.00	$2,872.91	$60.00	$66.92	$0.00	$0.00
2020	$1,980.00	$2,418.39	30.1%	1.00	$3,146.33	$60.00	$73.28	$0.00	$0.00
2025	$1,980.00	$2,648.56	30.1%	1.00	$3,445.78	$60.00	$80.26	$0.00	$0.00
2030	$1,980.00	$2,900.63	30.1%	1.00	$3,773.72	$60.00	$87.90	$0.00	$0.00

Table F-19. Wind, Onshore

Wind, Offshore (Floating Platform)

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	Not Commercial	Not Commercial	0.0%	Not Commercial	$0.00	$0.00	$0.00	$0.00	Not Commercial
2020	$4,200.00	$5,129.93	30.1%	1.00	$6,674.04	$130.00	$158.78	$0.00	$0.00
2025	$4,090.00	$5,471.02	30.1%	1.00	$7,117.79	$130.00	$173.90	$0.00	$0.00
2030	$3,990.00	$5,845.21	30.1%	1.00	$7,604.62	$130.00	$190.45	$0.00	$0.00

Table F-20. Wind, Offshore (Floating Platform)

Waste-to-Energy

Year Installed	EIA Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$8,312.00	$8,777.99	19.6%	1.00	$10,498.48	$392.82	$414.84	$8.75	$9.24
2020	$8,312.00	$9,613.42	19.6%	1.00	$11,497.65	$392.82	$454.32	$8.75	$10.12
2025	$8,312.00	$10,528.36	19.6%	1.00	$12,591.91	$392.82	$497.56	$8.75	$11.08
2030	$8,312.00	$11,530.37	19.6%	1.00	$13,790.32	$392.82	$544.92	$8.75	$12.14

Table F-21. Waste-to-Energy

Biomass Steam

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$3,830.00	$4,271.48	53.6%	1.00	$6,560.99	$95.00	$105.95	$15.00	$16.73
2020	$3,830.00	$4,678.01	53.6%	1.00	$7,185.42	$95.00	$116.03	$15.00	$18.32
2025	$3,830.00	$5,123.23	53.6%	1.00	$7,869.27	$95.00	$127.08	$15.00	$20.06
2030	$3,830.00	$5,610.82	53.6%	1.00	$8,618.22	$95.00	$139.17	$15.00	$21.97

Table F-22. Biomass Steam

Ocean Wave

Year Installed	NREL Capital Cost, 2009 $ $/kW	Capital Cost Nominal $ $/kW	EIA Adjustment Factor	Utility Adjustment Factor	Adjusted Capital Cost Nominal $ $/kW	NREL Fixed O&M, 2009 $ $/kW-year	Fixed O&M Nominal $ $/kW	NREL Variable O&M, 2009 $ $/MWh	Variable O&M Nominal $ $/MWh
2015	$9,240.00	$10,305.08	13.8%	1.00	$11,727.18	$474.00	$528.64	$0.00	$0.00
2020	$6,960.00	$8,501.02	13.8%	1.00	$9,674.16	$357.00	$436.04	$0.00	$0.00
2025	$5,700.00	$7,624.64	13.8%	1.00	$8,676.84	$292.00	$390.60	$0.00	$0.00
2030	$4,730.00	$6,929.29	13.8%	1.00	$7,885.53	$243.00	$355.99	$0.00	$0.00

Table F-23. Ocean Wave

G. Generation Resources

Electricity is typically produced through a turbine-generator process. The turbine rotates and drives a shaft in the generator to create electrical current.

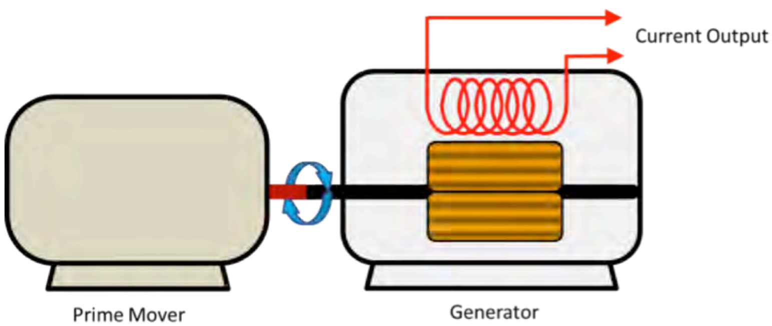

Figure G-1. Turbine-Generator Process

Turbines can be powered by different variable and firm sources. Variable energy is unpredictable because its energy source cannot be scheduled nor can it be controlled. Firm energy can be predicted, scheduled, dispatched, and controlled.

VARIABLE RNEWABLE ENERGY RESOURCES

Several variable renewable energy resources were considered in our PSIP analysis, all of which are currently in our generation mix. This type of energy is variable because its primary energy sources (such as wind, sun, and water) cannot be predicted.

The capacity value (essentially the percent of its "nameplate" generating amount that is available to the grid) of variable renewable energy varies by each resource, and is typically a small percentage of the nameplate value or zero. In addition, because the generation from variable renewable energy cannot be scheduled, it cannot be dispatched; in other words, it cannot be used to help regulate the balance between supply and demand.

Wind

Wind energy generation is the conversion of the wind's kinetic energy into electricity. Wind generating facilities are best located where wind is persistently steady. On Hawai'i with its terrain of hills, valleys, and ridges, variations in siting can have profound effects on the strength and quantity of wind currents.

As the wind turns a wind turbine's blades, the main shaft in the turbine rotates which in turn drives a generator (situated in the nacelle) to produce electricity. The annual capacity factor[1] of wind is generally about 25% at locations throughout Hawai'i, although it can attain a capacity factor of more than 50%.

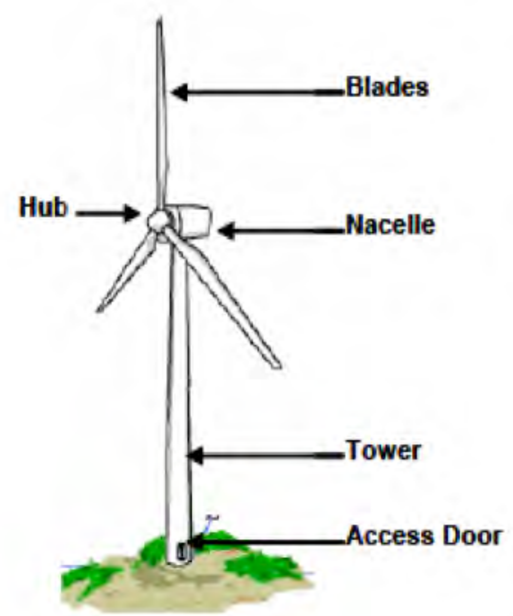

Figure G-2. Wind Turbine and Tower

A wind turbine shuts down when the wind is either too slow or too fast. The size of the wind turbine is generally in direct proportion to how much electricity can be generated. Larger wind turbines generate more power, while smaller turbines generate less. Thus, wind is a variable, non-dispatchable energy source.

[1] The Annual Capacity Factor, expressed in percent, is the amount of energy produced in a year compared to the amount of energy potentially produced by the facility if it was operated at 100% of its rated capacity for 100% of the time in the year.

Solar Photovoltaics

Solar photovoltaic energy is generated from its cells, and not by turning a turbine. Photovoltaic (PV) cells are made of semiconductors (such as silicon). When light strikes the cell, a certain portion of it is absorbed within the semiconductor material. The energy of the absorbed light is transferred to the semiconductor. The energy knocks electrons loose, allowing them to flow freely. This flow of electrons is a current, and by placing metal contacts on the top and bottom of the cell, this electric current can be drawn off for external use. The most common solar cell material is crystalline silicon, but newer materials for making solar cells include thin-film materials.

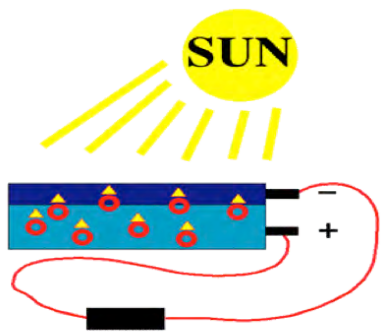

Figure G-3. Schematic of a Photovoltaic (PV) Cell and an Array of PV Panels

Solar PV is a variable renewable energy resource that cannot be scheduled and dispatched. Its annual capacity factor hovers between 18% to 22%. Solar PV only generates power when the sun is out and not blocked by clouds. On cloudless days, solar power gradually increases as the sun rises in the morning, peaks around 2 PM, and then gradually decreases until the sun sets. If at any point during the day a cloud blocks the sun, power output drops suddenly only to jump back up when the cloud passes. Thus, solar PV power generation can be erratic.

While solar PV systems can be made a few different ways, the most predominant is framed panels (as shown in Figure G-3). These panels consist of PV cells packaged as modules and framed into panels using aluminum framing, wiring, and glass enclosures. Multiple panels can be assembled into larger systems as arrays.

Distributed Solar Generation (DG-PV). These arrays can be installed on building rooftops, typically in a fixed direction as illustrated in Figure G-4. This rooftop solar is referred to as distributed generation because of the numerous small PV systems installed in many different locations distributed throughout the grid. These rooftop PV panels produce direct current (DC) electricity fed to an inverter which converts the electricity to alternating current (AC) for use by the building or home. Surplus PV electricity—more than the building can use—flows into the electric power grid.

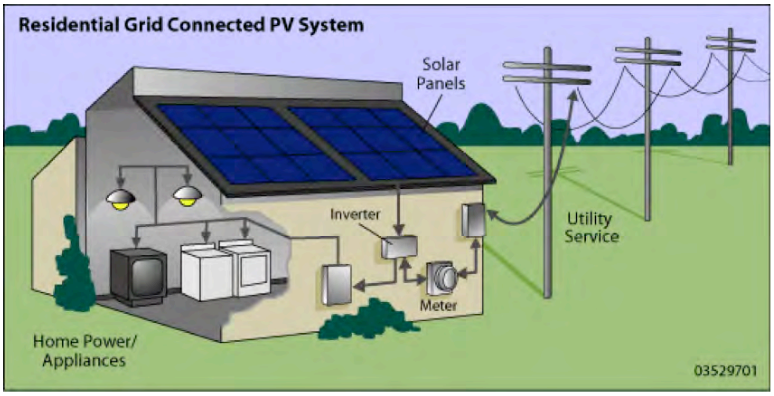

Figure G-4. Residential Distributed Generation PV System

Utility-Scale Solar PV. The PV panel arrays can also be mounted in large-scale ground mounted PV generating facilities (also referred to as "solar farms") that sometimes use tracking systems to actively tilt the PV panels towards the sun as it moves across the sky, thus increasing the annual capacity factor. These panels also produce direct current (DC) electricity. Inverters convert the electricity to alternating current (AC) where it immediately flows into the electric power grid.

Run-Of-River Hydroelectric

Hydropower is power derived from the energy of falling or moving water, which may be harnessed for useful purposes. Since ancient times, hydropower has been used to irrigate and operate various mechanical devices, such as watermills, sawmills, textile mills, dock cranes, and domestic lifts.

For run-of-the-river hydro projects, a portion of a river's water is diverted to a channel, pipeline, or pressurized pipeline (penstock) that delivers it to a waterwheel or turbine. If the river is not flowing, the hydroelectric facility produces no power. The moving water rotates the wheel or turbine, which spins a shaft. The motion of the shaft can be used for mechanical processes (such as pumping water) or it can power a turbine-generator to generate electricity.

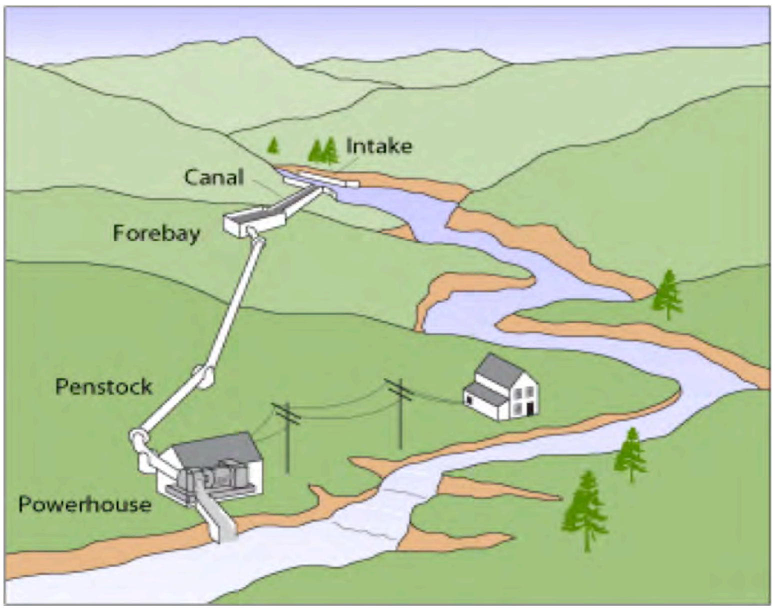

Figure G-5. Run-of-River Hydroelectric Plant

The primary development considerations are finding sites with adequate water flow and pressure, which are located in reasonable proximity to the electric grid for interconnection.

Energy Storage in Combination with Variable Renewable Energy

Wind, solar, and hydroelectric are all variable renewable energy sources. As such, they cannot be used to maintain the stability of an electric power grid, that delicate balance between supply and demand. Energy storage, however, can alleviate this situation and help provide more reliable energy, or in some cases, firm renewable power.

Energy storage can capture excess variable energy—generation that is not currently needed to meet demand—and store it in other forms until needed. This stored energy can later be converted back to its electrical form and returned to the grid as needed. Stored in high enough amounts, these sources could then be treated as firm power than may be scheduled and dispatched. (See Appendix J: Energy Storage Plan for more details.)

Pumped-storage hydroelectricity is a type of hydroelectric energy that includes energy storage. Water is pumped from a lower elevation to a higher elevation, where the stored water can be subsequently released through turbines to produce electricity. Electricity for pumping the water would typically occur during off-peak periods when the cost is low, or when during periods when there is excess energy generation from variable renewable resources. The generated electricity is then used during on-peak periods when demand is higher.

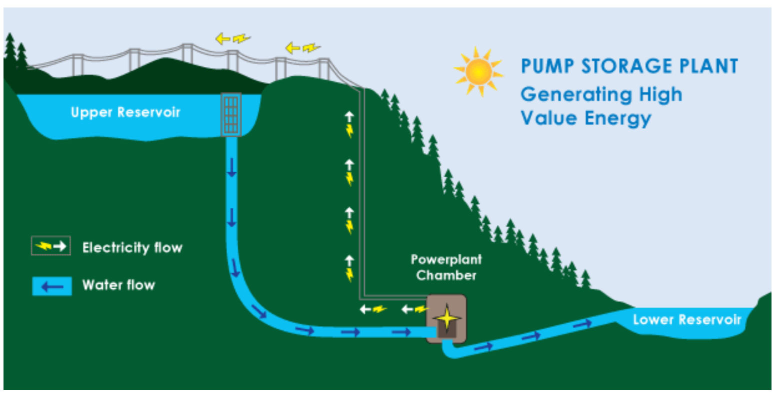

Figure G-6. Pumped Storage Hydroelectricity Plant

FIRM GENERATION

Several types of firm generation are included in our PSIP analysis, many of which are currently in our generation mix. Firm generation is predictable because its energy source (both fossil fuels and renewable fuels) can be scheduled, dispatched, and controlled.

The annual capacity value of firm generation can also be managed. A firm generation source can be operated as much or as little as necessary to meet demand. As such, firm generation is dispatchable; in other words, it can be used to help regulate the balance between supply and demand.

Gas Turbine Engine (or Combustion Turbine)

A gas turbine engine rotates as a result of hot gases (the product of the combustion of fuels) traveling through sets of turbine blades. As illustrated in Figure G-7, the flames themselves do not touch the turbine blades – just the gases produced by the flames. The combustor is where the fuel and air are mixed to enable the combustion process to occur. The fuel for this type of prime mover is either gas or liquid (not coal or biomass).

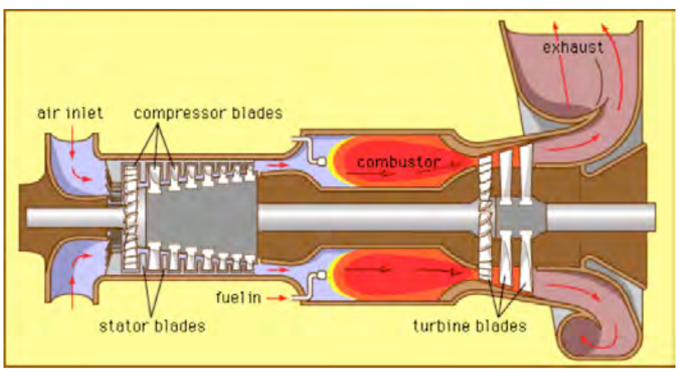

Figure G-7. Gas Turbine Engine

There are two types of gas turbines used for power generation: Aeroderivative and Frame.

Aeroderivative. This class of turbine is smaller (up to 100 MW) and can be quickly started and ramped, which makes them more compatible with grids that have large amounts of variable generation.

Frame. This type of turbine is generally larger (up to 340 MW), but not as fast reacting for both starting and ramping.

Gas turbines produce firm, dispatchable generation.

Steam Turbine: Combined Cycle and Boilers

A steam turbine operates by high pressure steam traveling through the turbine blades, causing the turbine shaft to rotate. This high pressure steam can be produced by a variety of technologies including Heat Recovery Steam Generators (HRSG) and fuel-fired boilers. All steam turbines produce firm, dispatchable generation.

Heat Recovery Steam Generators (HRSG)

HRSG use the high temperature exhaust gas from gas turbines engines to create steam for use in a steam turbine generator. This allows more electricity to be produced without using any additional fuel. The assembly of gas turbine, HRSG, and other auxiliary equipment used is referred to as combined cycle.

Hot combustion gases travel across the gas turbine blades to make the turbine spin where these gases are released at high temperature. A HRSG connects to the end of the gas turbine to take advantage of the energy that remains in the hot exhaust gases. The heat from these hot exhaust gases turns water contained in the HRSG into steam, where it is then sent to a steam turbine causing its connected generator to spin, thus producing electricity. Used steam is then converted back into water and reused again in the HRSG.

As illustrated in Figure G-8, combined cycle turbines can be either "single-train" (that is, one gas turbine and HRSG tied to the steam turbine) or "dual-train" two gas turbines and HRSG assemblies tied to a single steam turbine).

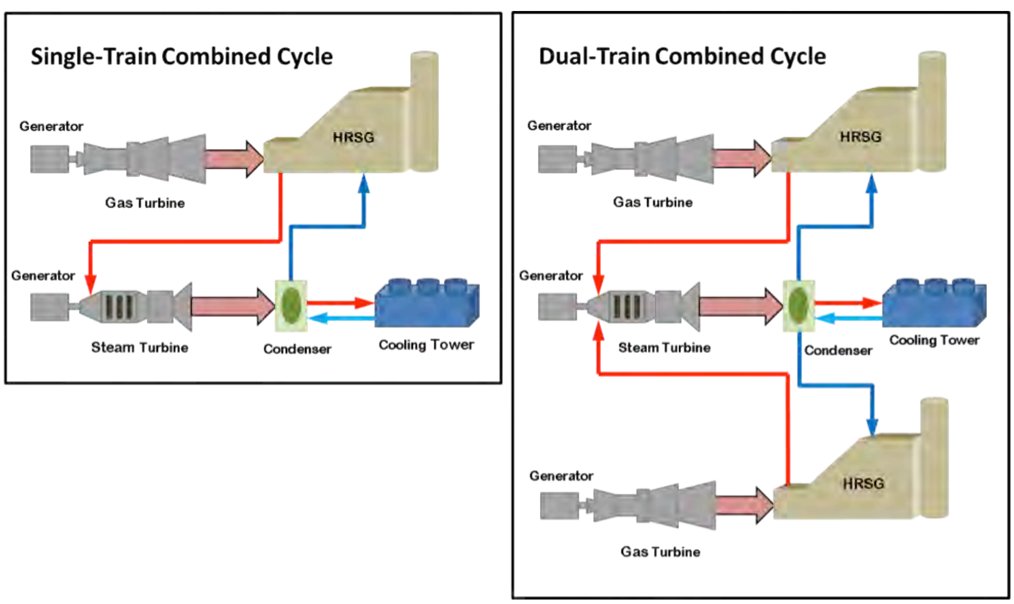

Figure G-8. Combined Cycle Plant: Single-Train and Dual-Train

A dual-train configuration provides twice as much power at a lower cost as a similar sized single-train configuration.

Reciprocating Internal Combustion Engine (RICE) or "Diesel Engine"

The type of reciprocating internal combustion engine used to produce electricity is a diesel engine. These engines can burn a variety of fuels, including diesel, biodiesel, biocrude, heavy oil, natural gas, and biogas. Diesel engines start and ramp quickly. Diesel engines produce firm, dispatchable generation.

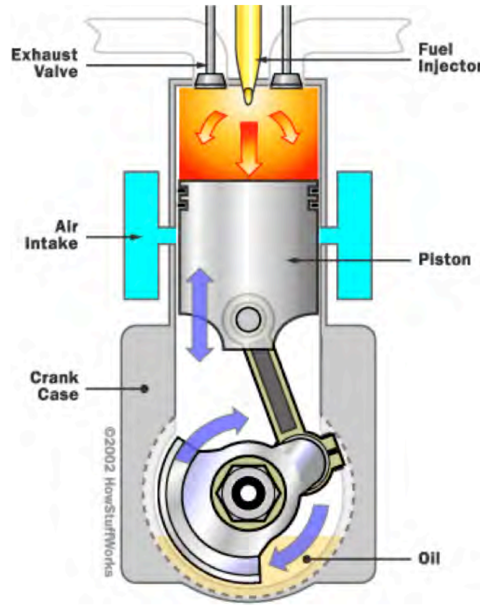

Figure G-9. Diesel Engine

Diesel engines have many combustion chambers called cylinders, each of which drives a piston connected to a common rotating shaft. This shaft is coupled to the generator to make it rotate. The number and size of these cylinders (illustrated as orange in the picture below) determine how much electrical output the engine can produce.

Diesel engine ratings can range from a few kW up to about 18MW. Larger diesel engines, because of their design, preclude them from meeting US Environmental Protection Agency (EPA) air emission limits. In addition, the EPA has different air regulations for diesel engines depending on the size of the cylinders.

Boilers (or Steam Generators)

A boiler furnace is made up primarily of small diameter (about 2-inch) metal tubes welded side by side to make a rectangular box. The tubes, which contain high purity water, are connected to a steam drum. The large fire inside the furnace transmits heat to the water inside the tubes to create steam in the steam drum. Fuel and air are continually added to the furnace to feed the fire.

Steam leaves the steam drum and travels through an independent set of tubes where it is heated to its final temperature by hot combustion exhaust gases. The steam then moves into the steam turbine, causing them to rotate and thus generate electricity. Boilers use a variety of fuels, including coal, biomass, liquid fuel oil, gas, and garbage.

Boilers come in many types, shapes, and sizes. Figure G-10 shows a simplified boiler steam turbine power plant. The boiler itself is outlined in the dotted red box.

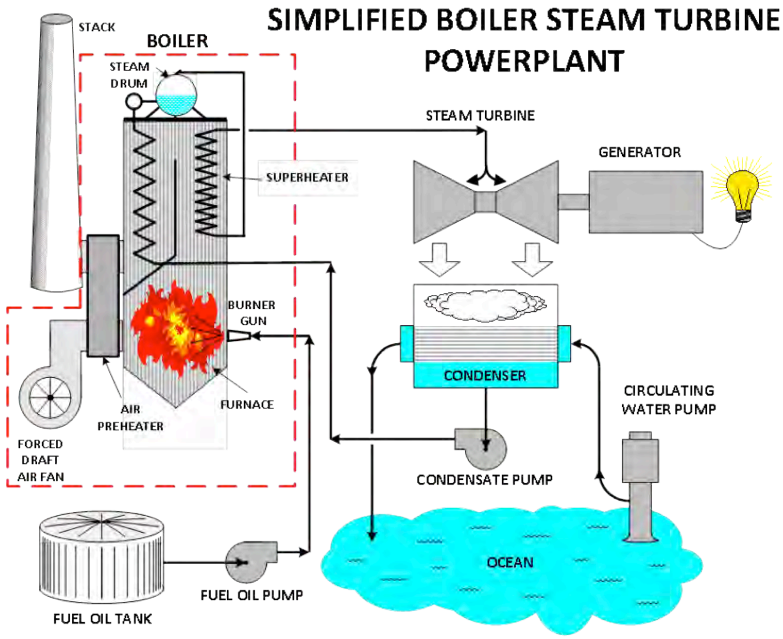

Figure G-10. Simplified Boiler Steam Turbine

Used steam can be converted back into water and reused in the boiler. A condenser forces the steam to travel over metal tubes that contain cold seawater, which causes the steam to turn back into water where it is pumped back into the steam drum, where the generation process begins again.

Renewable Fuel for Boilers–Waste (or Garbage)

Waste-to-energy is a renewable fuel-fired steam-electric power plant in which waste (or garbage) is burned in whole or in part as an alternative to fossil fuels. Paper, organics, and plastic wastes account for the largest share of solid waste used for the waste-to-energy stream. Incinerating solid waste to generate electricity is one method to reduce this waste volume. The fractions of solid waste—paper, wood waste, food waste, yard waste—are forms of a biomass fuel. Americans generate approximately 4.5 pounds of garbage per day. In Hawai'i, solid waste consists primarily of 30% paper, 25% other organics, and 12% plastics with the remainder comprised of metals, glass, and other materials.

Solid waste is mechanically processed in a "front end" system to produce a more homogenous fuel called refuse-derived fuel (RDF). RDF, in its simplest form, is shredded solid waste with the metals removed. This RDF must be processed further to remove other non-combustible materials such as glass, rocks, non-burnables, and aluminum.

Additional screening and shredding stages can be done to further enhance the RDF. The RDF is then fired in the boiler to produce steam that is directed to a turbine or generator.

In general, a robust waste-to-energy generation reduces the amount of landfill refuse by 90%.

Renewable Fuel for Boilers–Biomass

Biomass is another renewable fuel that can be used in boilers as alternatives to fossil fuels such as liquefied natural gas (LNG), oil, and coal.

Biomass is commonly defined as material derived from living organic matter (for example, trees, grasses, animal manure). Biomass includes wood and wood waste, herbaceous crops and crop wastes, food processing wastes such as bagasse, animal manures, and miscellaneous related materials. Biomass can be grown for the purpose of power generation from numerous types of plants, including switchgrass, hemp, corn, poplar, willow, sorghum, sugarcane, and a variety of trees such as eucalyptus and palm.

Biomass can either be burned directly to produce steam to make electricity, or processed into other energy products such as liquid or gaseous biofuel. In general, generating electricity directly from biomass is more efficient than converting it to biofuel. Siting a power generation facility at the source of the biomass, however, is not always feasible. Biofuel's transportability offers an attractive advantage.

Figure G-11 shows a process for converting wood waste into a biogas, which is then burned to create steam to generate electricity.

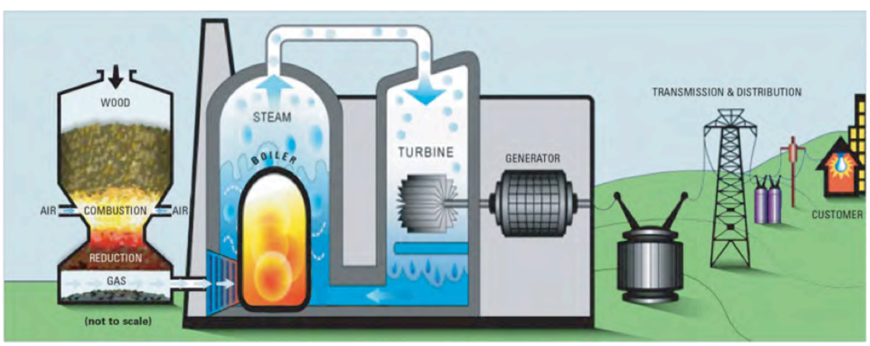

Figure G-11. Biomass Gasification

Aside from their fuel coming from renewable biomass, the power generation components of these facilities are similar to conventional power plants. In many cases, the power plants burn a combination of biofuel and fossil fuel.

Geothermal

Geothermal energy is heat energy from the earth. A layer of hot and molten rock called magma lies below the earth's crust. Heated ground water exposed to this magma can be extracted to provide geothermal energy at the surface. Resources of geothermal energy range from the shallow ground to hot water and hot rock found a few miles beneath the earth's surface where the earth's crust is thinner.

In general, geothermal fluids are tapped through wells, also referred to as "bores" or "bore holes". Except for the higher geothermal temperatures, these wells are similar to oil and gas wells. Geothermal well depths typically range from 600 to 10,000 feet. The fluids surging out of the wells are piped to the power plant. Geothermal steam, or vapor created using geothermal hot water, then spins a turbine-generator to create electricity.

The temperature and quality of the geothermal fluid determines which of the four types of power system that can be used for electrical generation.

Dry Steam Plants. Hot 100% steam is piped directly from geothermal reservoirs into generators in the power plant. The steam spins a turbine-generator to produce electricity. The steam is re-injected into the ground. Dry steam geothermal power plants are rare.

Flash Steam Plants. Fluids between 300°F and 700°F (148–371°C) are brought up through a well. Some of the water turns to steam, which drives the turbine-generator. When the steam cools, it condenses back into water and is re-injected into the ground.

Binary Cycle Plants. Moderately hot geothermal water (less than 300°F) is passed through a heat exchanger. This heat is then transferred to a working fluid (such as isobutene or isopentane) which boils at a lower temperature than water. When that fluid is heated, it turns to vapor which spins the turbine-generator.

Hybrid Plants. Combination of the flash steam and binary cycles.

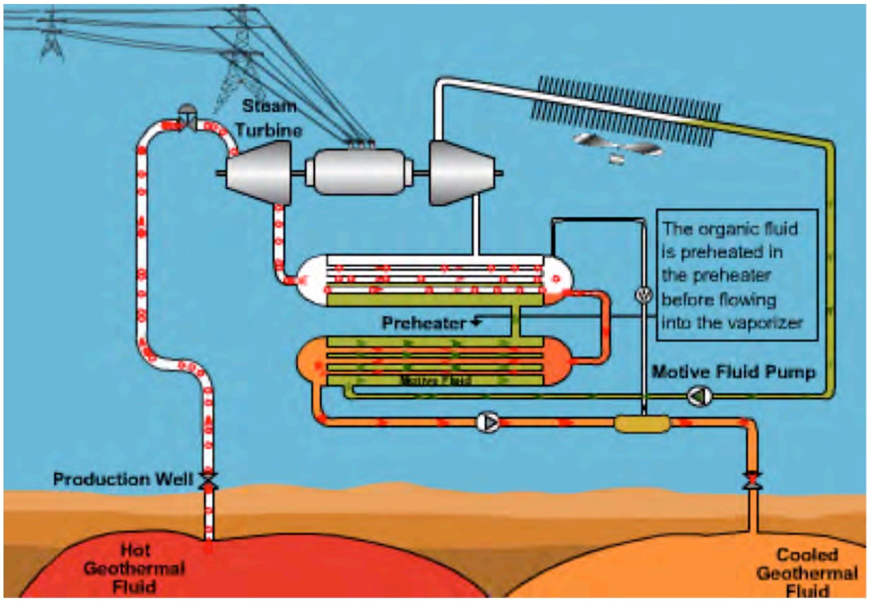

Figure G-12. Geothermal Hybrid Plant

In relation to other renewable energy projects, developing a geothermal power project is relatively complex, and typically involves two major phases: (1) exploratory drilling and (2) project development. The exploratory drilling phase identifies and evaluates potential resources, and drills test well. This phase usually takes a number of years, and in some case, does not identify a viable geothermal resource. After a geothermal resource has been identified, the project development phase begins, which includes drilling production wells and constructing a power plant.

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H. Commercially Ready Technologies

Our analysis for the PSIPs considered both commercially ready generation technologies as well as emerging technologies that, while not commercially ready, might become available during the planning period (2015–2030).

Which emerging technology will be commercially ready before 2030 is impossible to know with any degree of certainty. As a result, with one exception, we did not attempt to decide which of the most promising of the emerging technologies might become available during the planning period. The exception: our analyses performed limited sensitivity of some emerging technologies (for example, Ocean Thermal Energy Storage) to quantify any potential future value.

Our PSIPs are snapshots of the future based on our best available assumptions. As such, *for the PSIPs, we limited the generating resource options to those technologies that are commercially ready as of 2014.*

This planning assumption is for the PSIP analyses only, and does not affect our intent to thoughtfully consider specific projects that include emerging technologies. In other words, we welcome generating technologies not considered in the PSIPs that are proposed in responses to future request for proposals (RFP) for any of our power systems. We will evaluate any proposal on its commercial viability as well as other attributes that are consistent with RFP requirements. Further, nothing in these planning assumptions is intended to modify or change our position for welcoming test projects, pilot projects, or negotiations that involve any specific technology.

COMMERCIAL READINESS INDEX

In order to evaluate whether a technology is commercially ready, the Hawaiian Electric Companies used the Commercial Readiness Index (CRI) methodology developed by the Australian Renewable Energy Agency (ARENA), which was released in February 2014.[1]

NASA first developed a Technology Readiness Level (TRL) in 1974.[2] The TRL ranks technology readiness on a scale of 1 to 9 (1 being the lowest; 9 being the highest level of readiness), with specific attributes identified for each level of readiness.

In 2011, the U.S. Department of Energy published the *Technology Assessment Readiness Guide*,[3] a framework for evaluating energy technologies using the TRL methodology. The TRL methodology characterizes technology readiness from very early stages of a technology life cycle, up to and including commercial readiness.

Building on the work of NASA, ARENA developed a Commercial Readiness Index (CRI), and published the CRI criteria in February 2014 in a document titled *Commercial Readiness Index for Renewable Energy Sectors*.

The CRI scale (1 to 6, with 6 being the highest level of readiness) assesses technology readiness against eight indicators:

- Regulatory environment
- Stakeholder acceptance
- Technical performance
- Financial performance (cost)
- Financial performance (revenue)
- Industry supply chain
- Market opportunity
- Vendor maturity (preference for established companies with strong credit ratings)

ARENA maps its CRI to the TRL, with CRI level 1 corresponding to TRL levels 2 through 8, and CRI level 2 corresponding to TRL level 9. CRI levels 3 through 6, then, include more mature technologies that are closer to commercial deployment, or that are already being used commercially. Except for certain sensitivity analyses, the PSIP did not consider any technologies with a CRI level 4 or less.

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1 *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. http://arena.gov.au/files/2014/02/Commercial-Readiness-Index.pdf

2 "Technology Readiness Levels Demystified." August 20, 2010. http://www.nasa.gov/topics/aeronautics/features/trl_demystified.html#.U7W-g7ZdV9c

3 Technology Level Assessment Guide. September 15, 2011. http://www2.lbl.gov/dir/assets/docs/TRL%20guide.pdf

To evaluate power generating technologies included in analysis performed for the PSIPs, the CRI methodology provides practical, objective, and actionable guidance. Therefore, we used this methodology to evaluate emerging generation technology options and their suitability for inclusion as resource options in the PSIPs.

For the PSIPs, only those technologies with a CRI Level of 5 or 6 were considered commercially ready, and included as resource options in the PSIPs.

Table H-1 defines the levels of commercial readiness under the CRI methodology.

CRI Level	Commercial Readiness	Definition[4]
6	Bankable grade asset class	Financial investors view the technology risk as low enough to provide long-term financing. Known standards and performance expectations are in place, along with appropriate warranties. Vendor capabilities (including both technology vendors and EPC vendors), pricing, and other market forces drive market uptake ("demand pull").
5	Market competition driving widespread deployment	Competition is emerging across all areas of the supply chain, with commoditization of key components and financial products.
4	Multiple commercial applications	Full-scale technology demonstrated in an industrial (that is, not R&D) environment for a defined period of time. May still require subsidies. Publicly verifiable data on technical and financial performance. Interest from debt and equity sources, although still requiring government support. Regulatory challenges being addressed in multiple jurisdictions.
3	Commercial scale-up	Deployment of full-scale technology prototype driven by specific policy. The commercial proposition is driven by technology proponents and by market segment participants (a "supply push"). Publicly discoverable data is driving interest from finance and regulatory sectors, but financing products are not yet widely available. Continues to rely on subsidies.
2	Commercial trial	Small scale, first-of-a-kind project funded by 100% at-risk capital and/or government support. Commercial proposition backed by evidence of verifiable performance data that is typically not available to the public. Proves that the essential elements of the technology perform as designed.
1	Hypothetical commercial proposition	Technically ready, but commercially untested and unproven. The commercial proposition is driven by technology advocates, with little or no evidence of verifiable technical data to substantiate claims.
0	Purely hypothetical[5]	Not technically ready. No testing at scale. No technical data.

Table H-1. Commercial Readiness Definitions

[4] Based on *Commercial Readiness Index for Renewable Energy Sectors*. Australian Renewable Energy Agency. © Commonwealth of Australia, February 2014. Table 1. p 5.

[5] Not a part of the CRI methodology. Defined here to classify commercial readiness of certain technologies discussed from time to time in Hawai'i.

EMERGING GENERATING TECHNOLOGIES

In Hawai'i, certain emerging generating technologies are discussed as potential generating resource options. The most prominent of these are ocean wave/tidal power, ocean thermal energy storage (OTEC), and concentrated solar thermal power (CSP). We evaluated each of these technologies using the CRI ranking methodology. As objective as the CRI methodology attempts to be, the mapping of the indicators for a given technology is necessarily subjective. Reasonable differences of opinion in the state of any one (or even several) of the eight categories of indicators would not change the overall conclusion regarding the commercial readiness of these technologies.

Summary of CRIs for PSIP Resource Candidates

Table H-2 summarizes the commercial readiness of various generating resource technologies.

	CRI Level								
Technology	0	1	2	3	4	5	6	PSIP Resource Option?	Comments
Simple cycle combustion turbine (CT)							x	Yes	
Combined cycle CT + heat recovery steam							x	Yes	
Internal combustion engines—small							x	Yes	
Internal combustion engines—large							x	Yes	
Geothermal							x	Yes	Constrained on Maui and Hawai'i. None for O'ahu.
Biomass steam							x	Yes	
Biomass gasification			x					No	
Run-of-river hydro							x	Yes	Limited amount of MW available in Hawai'i.

Technology	CRI Level							PSIP Resource Option?	Comments
	0	1	2	3	4	5	6		
Storage hydro							x	No	No available streams to dam for water storage.
Pumped storage hydro							x	Yes	Not considered for base cases. Sensitivities only.
Ocean wave/ tidal				x				No	
Ocean thermal (OTEC)			x					No	
Wind—onshore utility scale							x	Yes	Limited on O'ahu.
Wind—offshore utility scale					x			No	High capital cost, concerns with ability to site and permit.
Wind—distributed generation				x				No	Approximately 3–4 times more expensive installed cost compared to solar DG-PV.
Solar PV—utility scale						x		Yes	
Solar PV—distributed						x		Yes	
Concentrated solar					x			No	
Fuel cells—distributed			x					No	Primary applications are for "high 9s" reliability applications (e.g., data centers).
Fuel cells—utility scale			x					No	
Micro nuclear reactors		x						No	
Solar power satellites	x							No	
Nuclear fusion		x						No	
Energy harvesting from ambient environment	x							No	Early markets will likely be small scale applications, such as PDA charging.

Table H-2. Commercial Readiness of Generating Technologies Considered for PSIPs

Evaluation of Emerging Technologies

Table H-3 through Table H-5 are CRI assessments of emerging generation technologies that were not included as resource options due to a CRI level of 4 or less.

Table H-3 evaluates wave and tidal power as a potential generating resource as, at best, CRI level 3. Therefore, it was not included for consideration in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5							Market opportunity widely understood. Additional policy support needed to drive uptake.	
4			Performance understood; high confidence in performance.					
3				Various versions of technologies deployed; Cost drivers beginning to be understood.				
2	Ability to permit across various regulatory jurisdictions untested.	Stakeholder support case-by-case basis.			Revenue projections being tested, however investment community not yet willing to underwrite PPAs on widespread basis.	Supply chain not available. Each project typically unique specification. EPC based on time and materials.		
1								Established industry players not yet part of sector.

Table H-3. Wave/Tidal Power Commercial Readiness Evaluation

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Table H-4 evaluates ocean thermal energy conversion as a potential generating resource as, at best, CRI level 3. Even though the CRI level would suggest that OTEC is not eligible for consideration at this time, due to interest in this technology for Hawai'i and our ongoing negotiations with OTEC International to build an OTEC facility to service O'ahu, a sensitivity was prepared to evaluate OTEC as a resource option for O'ahu.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6								
5								
4								Established player (LMCo) considered part of sector.
3							Size of potential market is understood.	
2	Regulatory issues require specific project consideration.	Stakeholder support a case-by-case basis.	Performance forecasts based on pilot project data.	Key costs based on projections. No data at scale.	Revenue projections at scale not tested.			
1						Key elements from specialists.		

Table H-4. Ocean Thermal Energy Conversion (OTEC) Commercial Readiness Evaluation

Table H-5 evaluates concentrated solar thermal power as a generating resource at a CRI level 4. While this resource might be considered during our next planning cycle, it was not included in the PSIPs.

CRI Level	Regulatory Environment	Stakeholder Acceptance	Technical Performance	Financial Performance (Cost)	Financial Performance (Revenue)	Supply Chain	Market Opportunity	Company Maturity
6							Market opportunities clear and understood.	
5					Target is to be cost competitive by 2020.[6]			Leading players with significant balance sheets in sector.
4	Permitting, regulatory challenges based on actual evidence. Policy settings moving to "market pull".	Evidence and experience available to inform stakeholders.	Performance understood. High confidence in future project performance.	Cost drivers understood and tested.	Financing still largely underwritten with government guarantees and subsidies.[7]	Limited supply options but improving.		
3			Multiple technology designs.					
2								
1								

Table H-5. Concentrated Solar Thermal Power (CSP) Commercial Readiness Evaluation

[6] See "*2014, The Year of Concentrating Solar Power.*" U.S. Department of Energy. May 2014.

[7] *Ibid.*

I. LNG to Hawai'i

Liquefied natural gas (LNG) is critical to reducing customer bills and improving environmental quality in Hawai'i. High oil prices and more stringent air regulations (the Environmental Protection Agency's Mercury Air Toxic Standards (MATS) and National Ambient Air Quality Standards (NAAQS)) increase the need to reduce Hawai'i's dependence on oil. While the majority of Hawaiian Electric's current generation portfolio utilizes oil, LNG has emerged as a viable alternative fuel source that may substantially lower fuel costs while reducing greenhouse gas emissions. In late 2012, the Hawaiian Electric Companies and FACTS Global Energy completed studies that confirmed both the technical and commercial feasibility for importing and utilizing LNG in Hawai'i.

DELIVERING LNG TO HAWAI'I

Natural gas is not indigenous to Hawai'i and must first be liquefied into LNG to be cost effectively transported to Hawai'i. LNG can be imported to Hawai'i in two ways: bulk LNG or containerized LNG

Bulk LNG. LNG could be transported in bulk via LNG carriers and/or articulated tug barges (ATBs) and received at a bulk LNG import and regasification terminal. The Floating Storage and Regasification Unit (FSRU) is a variant of this option. Pearl Harbor is the best site available for an FSRU when considering factors such as favorable meteorological-ocean conditions, spacious and protected harbor waters, security, cost, and ability to break-bulk (for distribution to the neighbor islands). Natural gas would then be distributed from the FSRU by pipeline to facilities on the individual islands where it would be consumed. Based on our discussions with FERC, we anticipate that a bulk LNG import and regasification terminal project for Hawai'i will take approximately

6–8 years to complete (1–2 years planning, 2–3 years FERC permitting, and 2–3 years construction) and could possibly be placed in service between 2020 and 2022.

Containerized LNG. LNG could be transported in International Organization for Standardization (ISO) containers using conventional container ships and trucks equipped to handle standard shipping containers. The LNG ISO containers would be delivered directly to the facilities where the LNG would be regasified and consumed. Since FERC permitting is not likely required for LNG delivered by ISO containers, LNG is available today in small quantities, and within a relatively short time for larger quantities.

Containerized LNG RFP

The Company issued an RFP in March 2014, for LNG to be delivered to Hawai‘i in ISO containers (Containerized LNG RFP). We have completed our evaluation of the proposals and have identified two proposals for more in-depth discussion with the bidders. We currently anticipate negotiating and executing a contract, and subsequently submitting an application to the Commission in the fourth quarter of 2014.

The Containerized LNG RFP called for deliveries to start within a window from October 1, 2016 to June 30, 2017. Based on confidential information received via the Containerized LNG RFP process, we believe that an LNG delivery commencement date in the latter part of 2017 remains viable if the following five key milestones are realized by their noted deadlines.

1. Finalization of the LNG Sales and Purchase Agreement (SPA) by fourth quarter 2014.
2. Application submission to the Commission by fourth quarter 2014.
3. Final Order to import LNG issued by the Commission by June 1, 2015.
4. Granting of all other major permits by June 1, 2015.
5. Clearance or waiver of any remaining LNG SPA conditions precedent by July 1, 2015.

Upon achievement of these milestones, we will make the investments necessary to construct, assemble and aggregate the various pieces of the supply chain needed to deliver LNG to Hawai‘i in 2017. It nevertheless must be recognized that these milestones are challenging, some of which are beyond our control and they will only be realized if no significant legal, environmental, or social obstacles encumber the process.

DELIVERING LNG IN 2017

Liquefaction Capacity

We believe that ensuring the availability of LNG supply from FortisBC is a critical component for successfully concluding the Containerized LNG RFP process with an executed LNG supply and logistics contract. FortisBC's liquefaction capacity is available under a regulated tariff as early as 2017 and capacity is reserved on a first come, first served basis. The Company believed it was critical to directly secure the required capacity from FortisBC before other parties stepped in. For this reason, on August 8, 2014, we executed an agreement with FortisBC for LNG liquefaction capacity under the FortisBC Rate Schedule 46. FortisBC's liquefaction cost, which is less than $2.70, is competitive with other liquefaction rates and is, in fact, lower than any other rate we are aware of (including the rates offered by other Gulf of Mexico liquefaction projects). In addition, because FortisBC is in British Columbia, Canada, they are not subject to the Jones Act and, therefore, can provide substantial marine transport savings to Hawaiian Electric through the use of international shipping assets.

COST OF SERVICE

The range of proposed conditional delivered LNG pricing to O'ahu power plants and to Hawai'i Island power plants is extremely favorable, and based on the assumed forecasted 2017 natural gas pricing of $3.58/MBtu.

The pricing mechanisms incorporate pass through provisions of most fixed and variable cost components, with the cost stack to be finalized upon filing of the LNG Sales and Purchase Agreement with the Commission. The build-up of the proposed pricing is based on bidders' current cost estimates, and the ranges for fixed, fixed with escalation, and variable price components.

Included in the fixed cost component are the capital assets (marine assets, ISO containers, etc.) and any services that can be contracted at fixed cost over the term of the SPA. The fixed with escalation cost component include the FortisBC liquefaction costs and other labor costs such as marine terminal handling charges and trucking. Included in the variable cost component is the gas commodity, pipeline toll, and fuel consumed for liquefaction, shipping, and trucking.

The Company and our advisors are undertaking due diligence on the cost elements for each segment in the supply chain. Liquefaction costs are set by FortisBC's Rate Schedule 46 and may be subject to periodic adjustments, if approved by the British Columbia

Utilities Commission (BCUC). Analysis to date suggests that there is little risk of a cost increase over the bidder's estimates, assuming the above stated milestone are achieved by the milestone dates and the SPA is effective no later than July 1, 2015. Discussions regarding the costs are ongoing with the bidders.

To account for the possibility of stranded assets that could result from a transition to a bulk terminal, a cost adder was included in the LNG forecast between the years of 2017 and 2021 to reflect the potential for a reduced amortization period (5 years versus 15 years).

Transition to Bulk Terminal: 2022

The development of a bulk receiving terminal will be subject to FERC review and approval and therefore cannot be realistically achieved by 2017. Siting of such a terminal, whether floating or land-based, will require substantial engineering analysis and stakeholder socialization. After consulting with FERC, a realistic schedule to develop a bulk LNG terminal is approximately 6 to 8 years.

The Galway Group estimated LNG pricing for 2022 and beyond by using current gas commodity forecasts, liquefaction costs from FortisBC, and estimated costs for shipping of the LNG and for a bulk terminal utilizing a FSRU. We are also assuming annual price increases in our forecasting. The build-up of the LNG forecast for 2022 is as follows:

Item	Price
Gas Commodity	$4.31
Pipeline Header (Fixed)	$0.60
Pipeline Cost of Fuel	$0.11
Marketer Fee (Fixed)	$0.01
Liquefaction (Fixed)	$1.99
Liquefaction Cost of Power	$0.91
Process Fuel Gas	$0.04
B.C. LNG Export Tax	$0.00
Marine Terminal	$0.33
LNG FOB FortisBC	$8.30
Shipping	$1.89
FSRU + Gas Pipeline	$2.54
2022 LNG Forecast w/ Bulk Terminal	$12.73

Table I-1. LNG Itemized Pricing

The LNG price forecast escalates beyond 2022 due to increases in the gas commodity price forecast, which is derived from NYMEX futures-derived forecasted values for Henry Hub; and 2% inflation adjustment applied to fixed with escalation and variable cost components.

J. Energy Storage For Grid Applications

Electricity is a commodity that is most efficiently produced when it is needed. The continuously varying demand for electricity requires utilities to have the appropriate mix of generating and demand-side resources to meet these varying demands. Energy storage is an extremely flexible tool for managing the supply-demand balance.

- Energy storage can be a substitute for generation resource alternatives;
- Energy storage can be used in conjunction with generation to help optimize generation capital costs and reduce system operating costs;
- For system security and reliability applications, storage has unique operational characteristics that may provide benefits not available through other resources.

The ability of energy storage to serve in any one of these roles is dependent upon the cost-effectiveness and operational characteristics of the energy storage asset under consideration, and the operational characteristics of all resources on the system.

Until relatively recently, the only way to store electricity in large (or bulk) quantities has been large mechanical storage devices (for example, pumped storage hydro, compressed air energy storage), which are highly dependent on site availability, may face substantial permitting and public acceptance challenges, have high capital costs and require long lead times (more than seven years) to develop. A new generation of chemical energy storage technologies (that is, batteries with new chemistries) and large-scale flywheel devices add to the commercially available options for energy storage in grid applications. In addition, there may be opportunities to aggregate customer-owned energy storage to provide value to all customers.

The Commission requested in the April 28, 2014 Decisions and Orders (D&Os) that the Companies consider the role that energy storage can play in managing the reliability of the electric grid. More specifically, the D&Os include the following topics for the Companies to address in the PSIPs:

- Discuss potential energy storage technologies and their capabilities;
- Analyze the fundamental benefit and costs of energy storage technologies;
- Discuss how energy storage is utilized in the preferred resource plan;
- Provide a plan for utilization of energy storage resources to address steady state frequency control and dynamic stability requirements, and to mitigate other renewable energy integration challenges;
- Provide a plan to improve utilization of existing energy storage on Maui and Lanai to improve system reliability and reduce system operation costs in those systems;
- Discuss the use of customer-side energy storage;
- Analyze the use of pumped storage hydro to provide ancillary services and bulk energy storage for renewable energy.

The Companies share the Commission's interest in energy storage for providing essential grid services. Energy storage has been integrated with certain independent power producer (IPP)-owned wind and solar projects to help manage ancillary service requirements. A project to design and procure storage for contingency reserves to mitigate the impacts from distributed solar on system security was initiated for the Hawai'i Electric Light system. Recently, a Request for Proposals (RFP) for commercial-scale and use of energy services to provide ancillary services was issued by Hawaiian Electric. As more fully described herein, the Companies have also implemented several pilot and demonstration projects.

This Appendix J will address the Commissions' questions about the Companies' plans to utilize energy storage in their systems.

COMMERCIAL STATUS OF ENERGY STORAGE

Pumped storage hydroelectric and compressed air energy storage technologies are mature and proven, with a great deal of performance data in commercial applications. Batteries (particularly lead-acid) and flywheel type energy storage devices have been around for many years and could also be considered mature technologies, but not for grid level applications such as renewable energy integration on island-based grids. The use of batteries and flywheel devices for use in bulk power systems and applications to integrate, or mitigate the impacts of, intermittent renewable energy in island-based electric grid systems is relatively new and there is somewhat limited data regarding their performance in commercial power grid applications. It is therefore worth discussing the status of commercialization of battery and flywheel energy storage for grid applications. This section will discuss several aspects[1] of the status of these technologies in terms of their commercialization. The evidence points to these technologies being at the cusp of commercially readiness.

Regulatory Environment

The regulatory environment for energy storage manufacturers is favorable. Most notably, on October 21, 2013 the California Public Utilities Commission (CPUC) issued the "Decision Adopting Energy Storage Procurement Framework and Design Program[2]." This CPUC decision set a target of 1,325 MW of energy storage to be installed in the three major investor-owned utility systems in California by the end of 2024. Other state commissions are looking at this CPUC decision[3]. This decision provides commercial opportunities for energy storage technology companies and energy storage project developers, and is therefore favorable for the commercial readiness of energy storage technologies. Of interest, the decision excludes pumped storage hydroelectric projects larger than 50 MW, a mature technology, from the target in order to promote development of smaller grid-scale storage projects.

At the federal level, the Federal Energy Regulatory Commission's (FERC) Order No. 755[4], required wholesale markets to develop compensation mechanisms for the provision of frequency regulation, a service that is technically well suited for certain energy storage technologies. The regulatory accounting treatment for energy storage remains an area that will require additional discussions by electric utilities and regulators[5]. For example, energy storage might be implemented for the purpose of relieving grid congestion (functionally classified as transmission), but the same energy storage project might also be able to provide ancillary services (functionally classified as a production service). Grid level energy storage might be implemented to mitigate the effects of variable distributed generation, while at the same time providing other grid support services. However,

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1 See Appendix G for a discussion of the "Commercial Readiness Index" (CRI) and the factors that are considered in determining a CRI.

2 Decision 13-10-040, October 17, 2013 (issued October 21, 2014). PUC Rulemaking 10-12-007. Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems. Full decision available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

3 "California poised to adopt first-in-nation energy storage mandate." San Jose Mercury-News. October 16, 2013.

4 *Frequency Regulation Compensation in Organized Wholesale Power Markets*. FERC Order No. 755. FERC Docket Nos. RM11-7-000 and AD10-11-000. Issued October 20, 2011. Order 755 available at: http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf

5 Bhatnagar, Currier, Hernandez, Ma, Kirby. *Market and Policy Barriers to Energy Storage Deployment*. Sandia National Laboratory. Report SAND2013-7606. September 2013. Report available at: http://www.sandia.gov/ess/publications/SAND2013-7606.pdf

when leveraging storage for multiple purposes, the energy storage must retain the necessary charge level to satisfy the requirements for each use. For example, storage that is deferring transmission investment must retain sufficient charge to handle the transmission constraint; that stored energy cannot be used to provide other services. These situations present issues for regulators in terms of ensuring that the benefits and costs of energy storage are properly allocated.

Stakeholder Acceptance

There are several dimensions to stakeholder acceptance of energy storage technologies, including:

Industry Acceptance: The electric utility industry, including non-utility project developers, has generally accepted grid-scale energy storage technologies as viable solutions for meeting grid needs. This is evidenced by installations of several hundred megawatts of energy storage worldwide in the past few years, including installations in Hawai'i in conjunction with wind and solar projects. Automotive applications for batteries in electric vehicles are expected to drive manufacturing costs down for lithium-ion batteries.[6] As a result, utility industry planners expect distributed energy storage to become more economical and are preparing for distributed storage integration into the future grid.

Equitable Regulatory Environment: Monetization of energy storage benefits is generally available in competitive wholesale market environments, where there are markets for capacity, energy and ancillary services. Monetization in vertically integrated utility markets (including Hawai'i) is generally driven by the cost effectiveness of energy storage relative to alternatives that provide similar functions. Cost recovery of energy storage systems is for the most part rationalized in the market. It is worth noting that energy storage project installations do not typically qualify for tax incentives, except in limited circumstances[7].

Public Concerns: Energy storage technologies are generally considered to be safe, however, there are public concerns with these systems related to potential fire hazards, toxic waste disposal, and dam breaches.

Financial Community Acceptance: Most of the capital invested in this sector to date has been in the form of venture capital funding, the purpose of which is to commercialize and refine the technologies and develop viable business models. To date, there is no known example of project level debt financing using project debt secured only by the revenues and the project itself (a typical financing model in the IPP industry). Rather,

[6] See for example: http://www.electric-vehiclenews.com/2010/03/deutsche-bank-battery-costs-appear-to.html

[7] For an example of such exceptions, see http://www.chadbourne.com/Large-Batteries-11-30-2011/

most of the projects have been financed off of the balance sheets of the developers themselves. As the market for energy storage becomes more of a "demand-pull" (as opposed to "supply-push") the interest of the mainstream investment community is growing. Several large financial institutions are marketing financing solutions for energy storage8. Some financial analysts predict that distributed energy storage, when combined with distributed solar PV, is on the cusp of being a technology that is disruptive to the traditional utility business model9.

Technical Performance

Although in general this industry is still in the formative stages, the technical performance of energy storage technologies, particular battery, flywheel systems, and pumped storage hydroelectric is well understood. And, with several hundred megawatts of grid-scale energy storage devices installed worldwide, the body of data is growing rapidly. The technical performance of most of the grid-scale energy storage projects to date (excluding pumped storage hydroelectric) is underwritten with technology performance guarantees (with liquidated damages provisions) from well-capitalized, strong balance sheet, engineering-procurement-construction (EPC) contractors and/or project developers.

Distributed energy storage is being marketed to customers interested in PV as well as enabled by the advent of electric vehicles (EV's) and the interest on the part of the sellers of EV's to address consumer "range-anxiety." Improvement in EV battery technology will increasingly find its way into distributed energy storage applications for consumers, including the ability to use EV's as a storage device for energy consumed in a customer's premises.

Financial Performance

The financial performance of energy storage is dependent upon the particular grid application and energy storage technology being deployed. Grid-scale energy storage costs are still relatively high[10]. In general, the cost of energy storage systems is declining, but challenges remain to deliver grid scale energy storage at low costs. Some sources believe that energy storage costs will decline precipitously over the next decade, at a rate of cost decline similar to that experienced with solar PV technology cost[11]. With respect

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[8] For example see: http://www.goldmansachs.com/what-we-do/investing-and-lending/middle-market-financing-and-investing/alternative-energy/

[9] See for example: http://www.utilitydive.com/news/barclays-downgrades-entire-us-electric-utility-sector/266936/

[10] See: Bhatnagar, Currier, et. al.

[11] For example, see: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

to value (benefits) of utility scale grid storage, as technology improves, the ability of energy storage to cost effectively provide grid services also increases.

Industry Supply Chain and Vendor Maturity

While the energy storage industry has its share of venture capital backed startups, large and well-capitalized equipment manufacturers now offer grid level energy storage technologies and solutions. These companies include, but are not limited to: General Electric, Hitachi, LG, Panasonic and NEC. Tesla Motors has recently announced that it is seeking a location for a large battery manufacturing plant in the US, to supply batteries for its EV's. They are actively developing utility uses for these same batteries and may find their way into grid storage applications, including distributed energy storage. Many of the smaller startups and niche players enjoy investments from, and strategic partnerships with, larger companies. These trends indicate that larger manufacturing companies are making the investments in sales, manufacturing, and service ecosystems that support the long-term viability of the energy storage industry. To date however, there is a lack of standardization in the energy storage industry.

Market Opportunity

The market opportunity for grid-scale energy storage is clearly validated by successful deployments worldwide and by regulatory mandates for energy storage as described above. Distributed energy storage is also viewed as a large market opportunity.

In conclusion, while the grid-scale energy storage industry is clearly in the early stages of commercial viability, it is well beyond the "technology development" stage for many of the available technologies. The Companies can be reasonably confident that energy storage solutions are available that can be designed, financed, constructed, operated and maintained in a manner consistent with the way the Companies deploy other kinds of utility grid infrastructure.

ENERGY STORAGE APPLICATIONS

Defining Characteristics of Energy Storage

Stored energy is generally referred to in physics as "potential energy." Potential energy is found in various forms; for example, the chemical energy stored in the form of a fuel, mechanical energy stored in a spring, gravitational energy stored in water in a reservoir, etc. In practice, most energy storage systems are used to store energy for use (that is, conversion to "kinetic energy") at a later time.

Energy storage systems of interest for electricity grid applications can be defined by the following set of characteristics:

Storage: Amount of energy that can be stored (measured in megawatt-hours)

Capacity (or rate of discharge): the rate (quantity per unit of time) at which the energy storage device can deliver its stored energy to the grid (typically measured in megawatts).

Storage Duration: Hours or minutes of energy storage (this is the amount of energy that can be stored divided by the rate of discharge).

Maximum Depth of Discharge: This is defined by the energy stored in the device at its minimum level divided by the total energy storage. This is a limiting factor in terms of the actual duration of delivery of stored energy from the device to the grid, since once the device reaches its maximum depth of discharge it cannot release any more of its stored energy. This can be a function of chemistry (for example, in a battery) or physical design (for example, in a pumped storage hydroelectric reservoir).

Round trip efficiency: This is the ratio of stored energy available for "release" from the device (AC energy out) to the amount of energy that must be expended to "fill" the device (AC energy in). The perfect storage device would have 100% round trip efficiency (that is, the energy output of the storage device would be equal to the charging energy required.) Actual storage efficiencies range from 70% to 90% depending upon the type of device, size and technology.

Duty Cycles Available: The number of charge/discharge cycles available from the device during a given period of time (measured in cycles per unit of time, for example, cycles per year, cycles per minute).

Grid Applications for Energy Storage

Generalized energy storage applications in electric power grids include the following:

Load Serving Capacity: Energy storage devices can be used to provide the equivalent of generating capacity, provided that the available storage duration is long enough (typically hours). Practical applications include substitution for peaking plants such as combustion turbines in markets where additional capacity is required[12]. In such an application, lower cost generating resources would be used to "fill" the energy storage device, and the stored energy would be released at a later time during peak hours. Load serving capacity requires relatively long storage durations (at least 3 hours to qualify as

[12] Denholm, Jorgenson, Hummon, Jenkin, Palcha, Kirby, Ma, O'Malley. The Value of Energy Storage for Grid Applications. National Renewable Energy Laboratory. NREL/TP-6A20-58465. May 2013. Available at: http://www.nrel.gov/docs/fy13osti/58465.pdf

"capacity" for the Companies' systems) but relatively infrequent use in terms of duty cycles (perhaps 50 – 100 cycles per year).

Time Shifting of Demand and Energy: Energy storage can be used to "shift" demand from one time period to another. Time shifting (also referred to as "load shifting") applications also typically require long duration (hours) of storage in order to be effective. In markets with substantial on-peak/off-peak energy price differentials, storage is valuable in financial arbitrage. In Hawai'i, there is not a large differential between the on peak and off-peak marginal cost of energy production; therefore, price arbitrage is not a primary consideration for energy storage at the grid level. Time shifting using energy storage may be useful in Hawai'i for managing the variability of some renewable energy resources, or to capture the available energy production from variable resources and store it for use at a later time, rather than "spilling" the available energy. Time shifting also requires relatively long storage durations, with the number of duty cycles being dependent on the nature of the market (for price arbitrage) or relative penetration of variable renewable energy and the frequency of curtailment events that could be avoided using energy storage.

Sub-Second Response: Fast acting energy storage can be used to supplement inertia and limit under-frequency load shedding that would occur during faults and other abnormities that occur on the grid, such as loss of generation. See Appendix E, Essential Grid Services.

Power Quality: Some energy storage devices can provide power quality and "ride-through" service. Power quality refers to the quality of the AC voltage in the system. Some energy storage devices can respond to changes in AC voltage by absorbing and releasing energy to "smooth" the sinusoidal AC waveform. For example, this type of functionality is used for some wind plants to ensure that equipment remains connected through transient system conditions.

These energy storage applications and the operational requirements associated with them are mapped in Figure J-1.

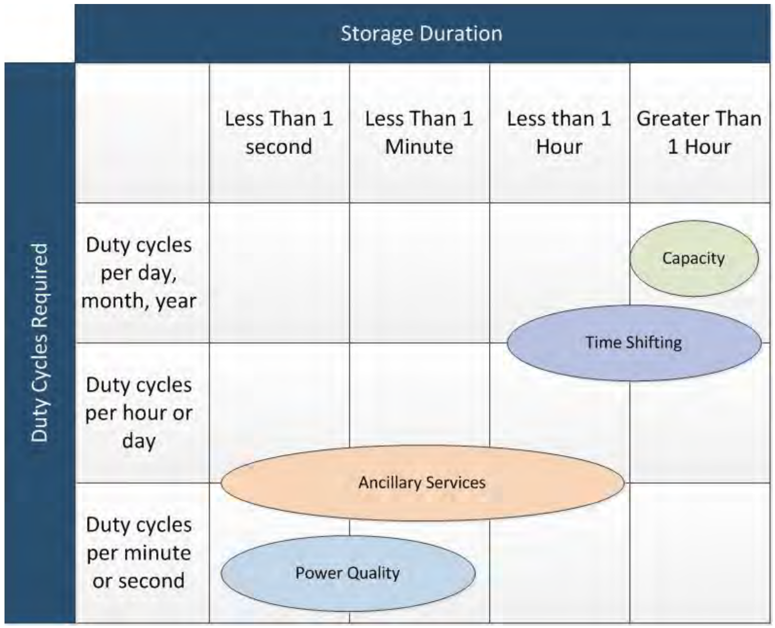

Figure J-1. Energy Storage Applications[13]

ENERGY STORAGE TECHNOLOGIES

Energy storage technologies can be categorized in terms of the physics utilized to store energy. These categories and the types of specific technologies include:

Mechanical: pumped storage hydroelectric (PSH), compressed air energy storage (CAES), flywheels. Underground CAES is not considered viable in Hawaiʻi due to lack of suitable geographic features and structural features conducive to CAES. However, aboveground CAES may be technically viable, but has not been considered at this time. PSH and flywheels are considered for Hawaiʻi and are discussed below.

Electrochemical: secondary batteries (lead-acid, lithium ion, other chemistries)[14], flow batteries. Lead-acid batteries, lithium ion and flow batteries are considered for Hawaiʻi and are discussed below.

Chemical: hydrogen (H_2), synthetic natural gas (SNG). These technologies are not considered for near-term applications in Hawaiʻi. A hydrogen infrastructure is, at best, a

[13] Adapted from International Electrotechnical Commission (IEC) Electrical Energy Storage Whitepaper, December 2011. Available at: http://www.iec.ch/whitepaper/pdf/iecWP-energystorage-LR-en.pdf

[14] "Primary" batteries cannot be recharged (for example, a dry cell flashlight battery). In "Secondary" batteries, the charge/discharge cycle can be reversed, meaning that secondary batteries can be recharged.

decade away. SNG is not economically viable as the round trip efficiency in very low (about 36%)[15].

Thermal: ice storage and grid interactive water heating. Ice storage and other forms of thermal energy storage are not considered here for bulk power applications. Several companies market thermal ice storage systems for managing end-use load (typically air conditioning) against tariff price signals[16]. Thermal energy storage can be useful for implementation by end-users in response to time-based pricing programs that are part of the Companies' demand response initiative (for example, grid interactive water heating).

Electrical: ultra-capacitors, superconducting magnet. These technologies are on the cusp of commercially readiness for grid-scale applications. Ultra-capacitors are increasingly being used in power quality applications[17]. Indeed, the Hawi wind plant in the Hawai'i Electric Light system utilizes an ultra-capacitor to ensure it remains connected through grid transients.

The following subsections briefly discuss the specific energy storage technologies that have been assumed to be available for consideration in the PSIP's. The inclusion of these technologies, and the exclusion of others, does not imply that the Companies are closed to considering other technologies. Specific energy storage proposals will be evaluated on their merits, including the commercial readiness of the technology proposed, utilization in specific grid-scale applications, and other relevant factors.

Flywheels

Flywheels are mechanical devices that store energy in the angular momentum of a rotating mass. The rotating mass is typically mounted on a very low friction bearing. The energy to maintain the angular momentum of the rotating mass is supplied from the grid. During a grid event, such as a sudden loss of load, the inertia of the rotating mass provides energy to drive a generator, which provides replacement power to the grid.

Flywheels are useful to provide inertial response in a power system. They are also increasingly used in commercial applications to provide fast-response, short-term "ride-through" capability that allows seamless transfer of load from the grid to a longer-term backup system such as an emergency generator. Flywheels display excellent load following characteristics over very short duration timeframes. Thus, they are well suited for providing frequency regulation and contingency reserves.

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[15] Pascale. KU Leuven. *Energy Storage and Synthetic Natural Gas.* (undated). Available at: http://energy.sia-partners.com/files/2014/05/Paulus_Pascale_ArticleUpdated1.pdf

[16] See for example Ice Energy. http://www.ice-energy.com/

[17] Daugherty, Leonard. SolRayo. *Ultracapacitors for Renewable Energy Storage*. (undated). Available at: http://www.solrayo.com/SolRayo/Presentations_files/Ultracapacitors_for_Renewable_Energy_Storage_Webinar.pdf

The capital cost of flywheels is fairly high. However, flywheels can provide hundreds of thousands of charge/discharge cycles over their useful life. Flywheel energy storage can be developed in two years or less, not counting regulatory approval lead-times. The round trip efficiency of a flywheel storage system is approximately 85%.

Other than specific site considerations, flywheels have very little environmental impact. Modern metallurgy has produced flywheel technologies that are safe during operation. Several vendors have designs that place flywheels underground for additional safety.

Advanced Lead Acid Batteries

Lead-acid batteries were invented in the mid 19th century. Conventional lead-acid batteries are characterized by low energy density (the amount of energy stored relative to the mass of the battery), relatively high maintenance requirements, and short life cycles. Their principle advantage is the ability to deliver high current over long duration timeframes. Disposal of lead-acid batteries presents environmental considerations, but recycling techniques are well established.

Advanced lead-acid batteries or "UltraBatteries" are now reaching the market. UltraBatteries combine conventional lead-acid batteries with electronic ultra-capacitors to provide high duty cycles. The supercapacitor enhances the power and lifespan of the lead-acid battery, acting as a buffer during high-rate discharge and charge[18]. This makes the UltraBattery a low cost, durable battery technology, with faster discharge/charge rates and a life cycle that is two to three times longer than a regular lead-acid battery[19].

Like all chemical energy storage systems, capital costs for advanced lead acid batteries are still relatively high for grid-scale applications. Round trip efficiencies are also high at around 90%.

Grid-scale advanced lead acid battery projects can be developed in two years or less, not counting regulatory approval lead-times.

The high market penetration of lead-acid batteries in automotive applications has led to successful lead-acid battery recycling programs. Not only does recycling keep lead out of the waste stream, recycling supplies over 80% of the lead used in new lead-acid batteries.[20]

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[18] *UltraBattery: No Ordinary Battery.* Australian Commonwealth Scientific and Industrial Research Organisation (CISRO). Available at: http://www.csiro.au/Outcomes/Energy/Storing-renewable-energy/Ultra-Battery/Technology.aspx

[19] *Ibid.*

[20] Conger, Christine. "Are Batteries Bad for the Environment?" Discovery News. September 16, 2010. Available at: http://www.nbcnews.com/id/39214032/ns/technology_and_science-science/t/are-batteries-bad-environment/#.U_ATm-VdVS8

Lithium Ion Batteries

"Lithium-ion" refers to a wide range of chemistries all involving the transfer of lithium ions between electrodes during charge and discharge cycles of the battery[21]. Lithium ion batteries are very flexible storage devices with high energy density, a fast charge rate, a fast discharge rate, and a low self-discharge rate, making lithium ion batteries ideal for grid applications[22].

Capital costs for lithium ion batteries are declining[23], particularly as the use of lithium ion for electric vehicle batteries rises. Lithium ion batteries themselves have a useful life through 400-500 normal charge/discharge cycles. More frequent use of the full charge/discharge capabilities of lithium ion would shorten the life. Lithium ion battery energy storage can be developed in two years or less, not counting regulatory approval lead-times.

The round trip efficiency for lithium ion technology is around 90%.

Lithium ion batteries do not contain metallic lithium, nor do they contain lead, cadmium, or mercury. Thus, disposal of lithium ion batteries is not a major issue. At the end of their useful life, lithium ion batteries are dismantled and the parts are reused.[24] Overcharging certain lithium ion batteries can lead to explosive battery failure. Thus, the overall safety of lithium ion batteries in grid applications is a function of mechanical design and control systems.

Flow Redox Batteries

A flow battery is charged and discharged by a reversible reduction-oxidation ("redox") reaction between two liquid electrolytes of the battery. Unlike conventional batteries, electrolytes are stored in separated storage tanks, not in the power cell of the battery. During operation, these electrolytes are pumped through a stack of power cells, in which a chemical redox reaction takes place and electricity is produced. The design of the power cell can be optimized for the power rating needed, since this is independent of the amount of electrolyte[25].

Advantages of flow batteries include virtually unlimited cycle life and fast charge/discharge times for the electrolyte, but the power cells do require periodic replacement. Increasing the size of the electrode stack can increase the power output of a

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[21] Energy Storage Association. http://energystorage.org/energy-storage/technologies/lithium-ion-li-ion-batteries

[22] *Lithium Ion Technical Handbook*. Gold Peak Industries (Taiwan), Ltd. http://web.archive.org/web/20071007175038/http://www.gpbatteries.com/html/pdf/Li-ion_handbook.pdf

[23] See for example: http://rameznaam.com/2013/09/25/energy-storage-gets-exponentially-cheaper-too/

[24] See for example: http://auto.howstuffworks.com/fuel-efficiency/vehicles/how-green-are-automotive-lithium-ion-batteries.htm

[25] This paragraph taken from: http://www.imergypower.com/products/redox-flow-battery-technology/

flow battery, and the storage capacity (energy) can be increased by increasing the size of electrolyte storage (or volume of electrolyte tanks). Flow batteries are useful for longer storage duration (hours) applications. Their relatively high capital costs make them less useful for ancillary service applications. Flow batteries are generally considered safe, an important issue for grid-scale batteries where thermal runaway of conventional batteries may cause fire[26].

Capital costs for flow batteries are still relatively high. The round trip efficiency of a flow battery is relatively low at around 72%.

Pumped Storage Hydroelectric

Pumped storage hydroelectric (PSH) is a mature technology that has been successfully implemented around the world in grid applications. In a pumped storage hydro system, water is pumped to a higher elevation using energy made available from generating resources that are otherwise unused (for example, low marginal cost off-peak energy or excess renewable energy that would otherwise be curtailed, etc.). During high demand periods, this stored water drives a hydroelectric pump-turbine to generate electricity.

Pumped storage hydroelectric has a relatively high capital cost, but has a useful life typically in excess of 50 years. Pumped storage is very efficient with round trip efficiencies approaching 80%.

Pumped storage hydro installations are very site dependent. Pumped storage investigations in Hawaiʻi have previously identified several potential sites in the Companies' service territories, with available output capacities typically less than 100 MW in size. Pumped storage hydro installations also face substantial siting and permitting challenges, particular where new reservoirs must be constructed and subsequently flooded. Because of the site specific challenges and the substantial engineering and construction efforts required to build a PSH project, the typical development time for pumped storage is seven years or longer, posing challenges to the utility planner, particularly in an environment where the need to deliver solutions in the near term is paramount.

Due to the inherent economies of scale, the preponderance of pumped storage hydroelectric installations in the United States are typically hundreds or even thousands of megawatts in size. There is very limited data on capital cost and performance for operating pumped storage hydroelectric installations that are less than 100 MW in size.

Pumped storage hydro is a very useful technology for providing peaking capacity and time shifting capabilities. While pumped storage hydro is a quick-start resource, the

[26] Lamonaca, Martin. "Startup EnerVault Rethinks Flow Battery Chemistry." MIT Technology Review. March 22, 2013.

water column constant of a typical pumped storage system is about 7 seconds (that is, this is the time it takes to get the water moving through the turbine to produce electricity). This is a limiting factor with respect to the utilization of an off-line pumped storage system for providing certain ancillary services. The utilization of adjustable speed pump turbine technology in pumped storage hydroelectric projects can provide operating flexibility compared to conventional pump turbines. The main advantage of using adjustable speed technology is the ability to provide more precise power control. This power control can be maintained over a wider operating range of the pumped storage hydroelectric system, allowing the utility to provide ancillary services, such as frequency regulation, spinning reserve, and load following, in both the generation and pumping modes. These benefits and other attributes of an adjustable speed pump turbine can translate into increased operating efficiencies, improved dynamic behavior, and lower operating costs.

Unlike a battery, which already has charge, or a flywheel that has angular momentum, the start of a pumped storage charging cycle requires the delivery of high levels of electric current to start the motors necessary to pump water to the higher elevation. To put this in perspective, a 30 MW pumped storage system in the Hawaiʻi Electric Light system would require staring 37.5 MW of motor load (assuming an 80% round trip efficiency). The typical daily peak demand of the Hawaiʻi Electric Light system is about 150 MW. Therefore, the start of the motor would represent an instantaneous load increase of 25% on the system. This may result in currents that exceed the short circuit limits of the transmission system, and without mitigation this would result in a significant frequency disturbance.

The primary environmental impacts from pumped storage hydro occur during construction. If construction of new reservoirs and/or water diversion is required, this can lead to substantial permitting challenges.

ECONOMICS OF ENERGY STORAGE

Energy Storage Capital Cost

The costs assumed in the PSIP's for energy storage systems are generally based on actual proposals for energy storage systems and flywheels, and from a combination of sources for pumped storage hydroelectric. The cost of energy storage for any given storage technology is in part a function of the duration of storage required. Table J-1 summarizes the capital costs assumed for the PSIP's mapped against the specific grid services required in the Companies' systems[27].

Grid Service	Storage Duration / Discharge	Technology: Flywheel $/KW	Advanced Lead Acid $/KW	Lithium Ion $/KW	Flow Redox $/KW	PSH $/KW
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	$997	NA	NA	NA	*
Regulating Reserves	30 min / 1000 cycles per year	$4,459	$1,005	$1,179	$1,596	*
Contingency Reserves	30 min / 20 cycles per year	$2,263	$802	$942	$1,079	*
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	$4,531	$5,401	$2,559	$4,500[28]

Costs include EPC, land, and overheads. Costs do not include AFUDC. NA = not economic, or unable to provide this service. * PSH may be able to provide these services when operating, but because the upper reservoir capacity of a given pumped storage project site is defined by geology and other factors, PSH would not typically be economical to build for the sole purpose of providing very short duration services.

Table J-1. Energy Storage Technology Capital Cost Assumptions (2015 Overnight $/KW)

Energy Storage Fixed O&M

The PSIP fixed O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric, which is based on NREL data. Table J-2 summarizes the storage fixed O&M costs.

Grid Service	Storage Duration / Discharge	Technology: Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	58	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	264	31	32	43	NA
Contingency Reserves	30 min / 20 cycles per year	108	25	27	29	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	90	105	62	29

Table J-2. Energy Storage Fixed O&M Assumptions (2015 $/KW-Year)

[27] See Appendix E for a discussion of Essential Grid Services in the Companies' systems.

[28] There is relatively little actual data available regarding the cost of utility-scale pumped storage projects less than 100 MW in size. This capital cost assumption for pumped storage used in the PSIP analyses was determined though evaluation of a number of different sources, including a review of confidential screening-level cost estimates for site specific projects in Hawai'i, estimates for a 50 MW pumped storage project in the United Kingdom, NREL data, U.S. Energy Information Administration data, and conversations with a potential pumped storage developer in Hawai'i.

Energy Storage Variable O&M

The PSIP variable O&M cost assumptions for energy storage were also based on actual proposals, except for pumped storage hydroelectric O&M, which is based on NREL data. The variable O&M costs for batteries is solely related to battery and cell replacements and disposal at the end of the duty cycle of the batteries which are assumed to require replacement due to high number of charge/discharge cycles per year associated with provision of regulating reserves. Table J-3 summarizes the storage variable O&M costs

		Technology				
Grid Service	Storage Duration / Discharge	Flywheel	Advanced Lead Acid	Lithium Ion	Flow Redox	PSH
Inertial, Fast Response Reserves	0.05 min / 5000 cycles per year	NA	NA	NA	NA	NA
Regulating Reserves*	30 min / 1000 cycles per year	-0-	88	45	30	NA
Contingency Reserves	30 min / 20 cycles per year	NA	NA	NA	NA	NA
Capacity, Long-term Reserves	> 3 hours / 50 cycles per year	NA	NA	NA	NA	59

Table J-3. Energy Storage Variable O&M Cost Assumptions (2015 $/MWH)

Benefits of Energy Storage

In the Companies' systems, energy storage can be used for several purposes.

- Capacity to serve load
- Manage curtailment of variable renewable generation
- Ancillary services
- Integration of renewables

Benefits of energy storage for each of the above uses depend upon specific operating conditions, the capacity adequacy situation in each of the operating systems, and the other resource options available. In general, energy storage can also be used for multiple purposes. For example, energy storage installed to provide capacity to serve load, could also be available to provide ancillary services, provided it is not being used in its load-serving mode. However, if the storage asset is will be used for multiple purposes, it must be designed to ensure the energy allocation and response capability can serve the combined needs. For example, storage used for contingency reserves must be kept at the necessary charge level to provide the required reserve. If also providing regulation, additional energy storage capacity would be required above the minimum required to meet the contingency reserve requirement.

Capacity

Energy storage can provide capacity to serve load on the Companies' systems, provided that there is a need for capacity[29] and provided that there is the appropriate duration of energy storage available to qualify as capacity[30]. During the PSIP planning period, the Hawaiian Electric and Maui Electric systems are expected to add capacity to replace retiring generation. Thus, energy storage is one of the alternatives that must be considered for providing that capacity.

Figure J-2 conceptually depicts the economic comparison of energy storage to generation for providing capacity.

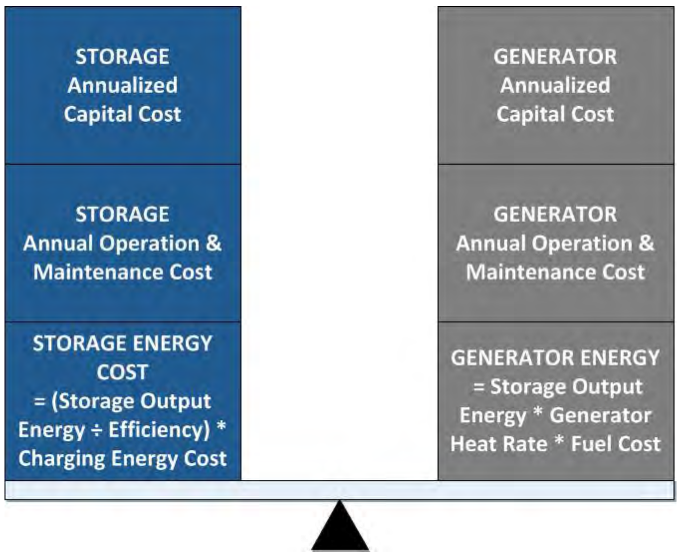


Figure J-2. Energy Storage Economics for Capacity

In this comparison, the energy storage device is compared on a one-for-one basis as a substitute for a generator. A levelized utility revenue requirements factor is applied to the total capital cost of the storage and the generator to determine the annual capital costs. The O&M costs associated with the two alternatives are determined. And finally, the cost of the energy output from each of the assets is computed. In the case of the storage technology, the round trip efficiency must be taken into account, because more energy is required to charge the energy storage asset than is usefully delivered from the same energy storage asset. If the total cost of the energy storage asset were less than the cost of the generator, energy storage would be the most economical alternative[31]. Note that in the case where capacity is not needed, the capacity cost of the generator would be

[29] Denholm, Jorgenson et. al.

[30] Storage is a finite energy resource. When used as a capacity resource, the storage must be carefully designed for the appropriate duration, and the storage energy must be utilized in an appropriate manner. The Companies' criteria require that a resource be able to deliver energy for 3 continuous hours in order to qualify as capacity.

[31] In a proper analysis, any differences in ancillary service costs or benefits associated with the alternatives being compared will also be included.

zero, because existing generation (whose capital cost is sunk) would be able to provide amount of energy required by the system.

Managing Curtailment

Energy storage used to manage variable renewable energy curtailment is an example of a time shifting application for storage, and may have use in the Companies' systems. Energy storage can absorb variable renewable energy that is produced when it is not needed, and return that energy (less round trip losses) to the system at a later time. Figure J-3 conceptually depicts the economics of energy storage in managing curtailment.

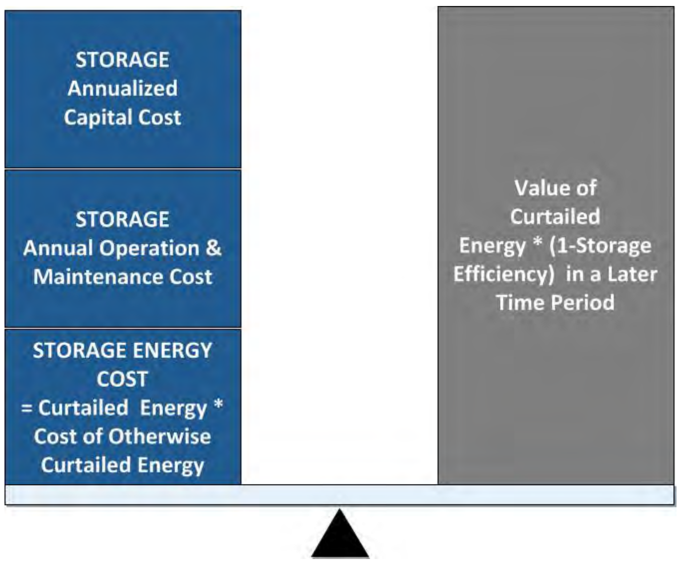


Figure J-3. Energy Storage Economics for Managing Curtailment

The basic economic equation in Figure J-2 is a comparison of the cost of the energy storage versus the value of energy in a later time period of energy that would have otherwise been curtailed (less the round trip efficiency losses since that those losses will not be returned to the system). Note that in Figure J-2 there is a cost associated with the curtailed energy used to charge the energy storage device. Absent the energy storage asset, the payment for the curtailed energy would have been avoided. Thus, this is a cost that is borne by the ratepayer that would otherwise have not been incurred. Further study of Figure J-2 will reveal that the cost comparison includes the capital cost of the energy storage, but it does not explicitly include any capacity value (that is, capital cost) associated with use of the energy in a later time period. Unless there are severe capacity constraints in the system where new capacity is required, the capacity value of the energy used at a later time is essentially zero. At current Company system marginal cost levels, it would almost never be economical to build energy storage exclusively for the purpose of managing energy curtailment. Rather, it is more likely that an energy storage asset already installed for another purpose could also be used to manage curtailment.

Ancillary Services

Energy storage can be used to provide ancillary services, provided that it can respond in the time frames necessary and operate in a coordinated fashion with other generation and demand response resources on the system. Using energy storage to provide ancillary services slightly increases total amount of energy that must be generated in the system due to the round trip losses associated with the energy storage asset. The charging energy may come from thermal resources or from variable renewable resources. However, energy storage may allow energy production costs to be reduced if provision of ancillary services is causing a constraint on the economic commitment and dispatch of generating units. These economics are depicted in Figure J-4.

The value of the energy storage asset in this situation is based on production cost savings (fuel and O&M) that are incurred by storage supplying the ancillary services. Calculation of these benefits requires production simulations.

If capacity is required in the system, short duration energy storage may be more cost effective than adding new generating capacity. If that is the case, the capital cost of the new generation must be added into the benefits that storage can provide.

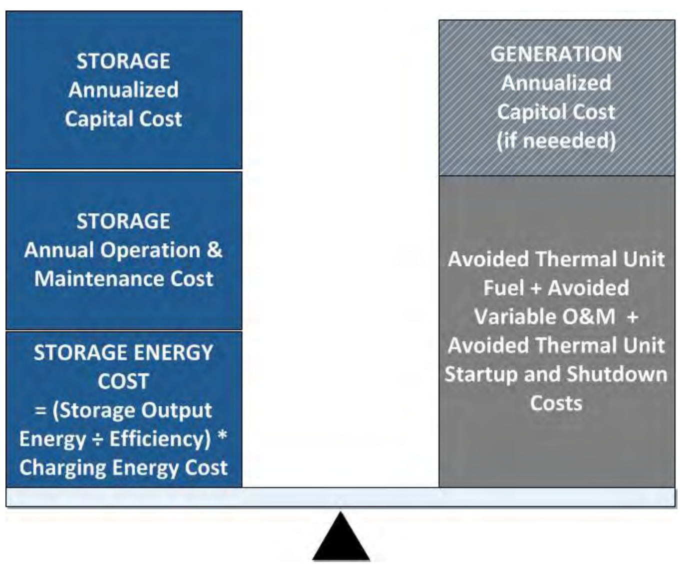


Figure J-4. Energy Storage Economics for Ancillary Services

Integration of Renewables

Another possible use of energy storage in conjunction with renewable energy is to combine the installation of a variable renewable generator with the installation of energy storage. This has been accomplished in the all three of the Companies' main operating systems. The value of this configuration for customers is that it essentially allows the storage to be leveraged to minimize the ancillary service requirements created by the variable generator that would otherwise have to be provided by other resources on the system. Location of storage at the plant allows the sizing to be designed for the plant needs; co-location also simplifies the communications control interface. From a system standpoint, the storage/generation combination is treated as a plant with the combined operational/technical capabilities of the turbines and storage. The economic evaluation is essentially the same as that portrayed for ancillary services in Figure J-4.

It should be noted that in several cases, the installation of the energy storage was feasible only because it was bundled with generation in a way that allowed the project developer to obtain tax advantages for the energy storage that would not be available for a standalone energy storage asset. In other words, energy storage added value to the generation.

Unless marginal thermal generation costs were much higher than they are today, the converse is not true (that is, adding generation does not add value to storage). It does not make economic sense to build excess renewable generators exclusively to provide energy to charge storage assets since in doing so, the marginal capital cost would be the sum of the generator capital cost and the storage capital cost. Rather, it is important that the system be planned to optimize all resources, including generation, demand response, and storage to achieve the lowest cost.

K. Capital Investments

This information represents the 2015–2030 capital expenditure budget for the Hawaiian Electric Company.

TRANSFORMATIONAL INVESTMENTS

The transformation of the O'ahu electric grid to reliably and cost effectively enable more renewable generation requires significant investment in virtually every aspect of the business. Investments ranging from new renewable generation resources to enabling technologies for demand side resources and from DGPV enabling grid reinforcements to infrastructure for lower-cost LNG fuel will transform our Island grid. These transformative investments are described below more in depth.

Liquefied Natural Gas (LNG)

In an effort to reduce customer costs, Hawaiian Electric is pursuing two non-exclusive approaches to import lower-cost LNG to Hawai'i: importation of LNG via ISO (International Organization for Standardization) containers (containerized LNG); and/or importation of LNG via bulk LNG carriers (bulk LNG).

The concept of containerized LNG would involve using conventional container ships and trucks equipped to handle ISO containers. The LNG ISO containers would be delivered directly to the generating stations where the LNG would be regasified and consumed. Shipping and distribution of containerized LNG to Hawai'i in volumes sufficient for power generation may possibly be commercialized within three years or less.

The bulk LNG concept would involve transporting LNG across the ocean via LNG carriers and/or articulated tug barges, and receiving it at a bulk LNG import and regasification terminal (likely located in Pearl Harbor). Once regasified, natural gas would be distributed by pipeline to generating stations where it would be consumed. It is anticipated that development, permitting, and implementation of a bulk LNG import and regasification terminal for Hawaiʻi will take up to eight years to complete, and could possibly be placed in service in 2020 to 2022.

Regarding containerized LNG, Hawaiian Electric solicited offers from third parties for containerized LNG deliveries via a March 11, 2014 request for proposals (RFP) and final bids from three potential suppliers were received on May 24, 2014. The responses to the RFP indicate that containerized LNG could be delivered to generating stations on Oʻahu and neighbor islands up to an approximate 30% discount below current petroleum fuel prices. Based on these proposals, Hawaiian Electric intends to move forward as quickly as it can to bring containerized LNG to Hawaiʻi and to use it in existing and future replacement generating units.

It appears that importing containerized LNG will have the potential of saving the Companies' customers throughout the state substantial amounts on fuel costs. The amount of the savings will depend on the prices for the fuels that are displaced once LNG is available, and the final prices from the on-going RFP. It is uncertain at this time whether a bulk LNG delivery solution would provide as much, the same or more of a cost benefit to customers. Therefore, Hawaiian Electric will continue to pursue the bulk LNG concept as long as there is a potential that it will provide additional benefits and value to our customers.

System Security Investments

To reliably operate a grid rich in variable renewable generation requires the grid operator to manage a new, and to some extent not fully known, set of electrical system security issues. When such a grid is a small islanded system such as Oʻahu, the criticality of these issues is further heightened, as compared to the large, interconnected grids of North America. The Company's system security analyses, coupled with the PSIP planning processes, have defined a number of new investments required to meet these system security challenges. These investments, "Energy Storage – Contingency Reserve" and "Energy Storage Regulating Reserve," enable the Company to comply with its system security and reliability standards by 2016 and maintain compliance with these standards through the remainder of the study period.

Investments also include telecommunications infrastructure additions to provide SCADA functionality to all distribution substations. SCADA provides for information and control of distribution substation devices for improved reliability and situational awareness. It also provides the communication link to communicate with utility and customer equipment located within and connected to distribution circuits. These include communications to facilitate dynamic under frequency load shedding; provides a "backhaul" for Distribution Automation, AMI, and other Smart Grid technologies; and is a necessary communications link to take advantage of "smart" inverter capabilities, including inverter status, voltage regulation, active inverter control/regulation, and other functionality as described in the DGIP.

Additionally, investments will also include a new Energy Management System (EMS) to replace the current EMS when it reaches the end of its product lifecycles and to take advantage of state-of-the-art hardware and software technologies to properly operate a grid with significantly more monitoring and control points than in the past and to allow for the coordinated operation of the system – both automatic generator controls and T&D switching—and also to interface with the Advanced Distribution Management System (ADMS) and Outage Management System (OMS) planned to allow for coordination with circuit/area-level grid operations such as DR, DA, DG, EV and operations and monitoring of other DERs.

Facilitation of New or Renewable Energy

138KV Transmission Loop

A new 138kV transmission line from Koʻolau Substation to Wahiawa Substation (along the windward, northern, and central areas of the island) would accommodate additional renewable energy in the future on the central and northern areas of Oʻahu. This transmission line would be approximately 55 miles. Currently, no transmission circuits exist on this part of the island. In addition, at least one new transmission substation would be required along the 138kV line. The transmission substation would be built to accommodate an ultimate design for six 138kV breakers (in a breaker-and-half scheme), two 138-46kV, 80MVA transformers, a 46kV ring bus, and four 46kV feeder breakers.

The existing 46kV feeders serving the North Shore and Kahuku areas from Wahiawa Substation and Koʻolau Substation are already at their capacity limits with existing and proposed wind farms and PV generation. Adding this new transmission line with a new transmission substation would add 46kV capacity that can accommodate additional renewable generation on that side of the island. It would also increase the grid reliability on the North Shore area and strengthen power quality.

DG Enabling Investments

The Distributed Generation Improvement Plan (DGIP) lays out an aggressive plan to enable the integration of significant amounts of new distributed resources, which are expected to be primarily rooftop PV. This plan calls for investments to enable "clearing the existing queue" within the next 18 months, and investments enabling total interconnected DGPV to reach 650MW (for O'ahu) by 2030. This will continue to provide our customers with an important option to manage their electricity costs and contribute to meeting State RPS goals.

The DGIP includes a Distribution Circuit Improvement Implementation Plan (DCIIP) that summarizes specific strategies and action plans, including associated costs and schedules, for circuit upgrades and other mitigation measures to increase the capacity of the Companies' electrical grids and enable the interconnection of additional DG.

In evaluating each company, by circuit and substation transformer, improvements to allow for greater interconnection of DG include: (1) updating LTC and voltage regulator controls to be capable of operating properly under reverse-flow conditions; (2) upgrading substation transformer capacity when load and DG are greater than 50% of capacity in the reverse direction; (3) upgrading primary circuit capacity when load and DG are greater than 50% of capacity in the reverse direction; (4) upgrading customer service transformer capacity when load and DG are greater than 100% of capacity, which also mitigates high voltage; (5) adding a grounding transformer to circuits when 33% of DML is exceeded for applicable circuits; and (6) adding a grounding transformer of 46-kV lines when 50% DML is exceeded. Each of these mitigation measures provides different values to both the utility and the distributed PV owner.

Smart Grid and Demand Response

At the Hawaiian Electric Companies, we are committed to achieving modern and fully integrated electric grids on each of the islands we serve—grids that harness advances in networking and information technology and, as a result, deliver tangible benefits to our customers and the state of Hawai'i. To accomplish this, we plan to invest in smart grid.

A smart grid modernizes our electrical grid enabling a more seamless integration of renewable energy, increasing reliability and efficiency, helping the environment, and lowering costs—all without compromising safety or the quality of electric service. In addition, the smart grid enables customers to make wiser choices that can guide their energy choices.

Please refer to our Smart Grid filing for more details about our smart grid roadmap.

Two-Way Communications System

The backbone of our Telecom System (fully owned by the Hawaiian Electric Companies) acts as an enabler for all of our operational and corporate business applications, including the smart grid applications. The Hawaiian Electric Companies enterprise telecommunications network or backbone is commonly referred to as our Wide Area Network (WAN) and Field Area Network (FAN). The smart grid applications and end devices (such as the smart meters), fault circuit indicators (FCIs), SCADA-enabled distribution line transformers and switches, reside in the Neighborhood Area Network (NAN), which is located beyond the WAN and FAN networks. The foundation of the smart grid platform (the NAN) we intend to implement is a two way communications network that connects points along the distribution grid to our back office software. Smart grid applications run on that network providing detailed information about the performance of the distribution grid.

AMI uses the secure IPv6 network that employs wireless 900MHz radio frequency mesh technology. This wireless technology consists of: access points; routers enabling devices communicating over the radio frequency mesh network to connect to our IT infrastructure through wired or cellular connections; relays, which are repeater devices that extend the reach of the radio frequency signal; and intelligent endpoints (such as third-party smart meters outfitted with network interface cards from Silver Spring Networks).

All Silver Spring Networks devices contain a one watt, two way radio. These devices connect with each other to form a mesh that makes up the Neighborhood Area Network (NAN). Access points and relays will be designed to have multiple paths through the NAN and the utility's WAN to provide high-performance, redundant connections between endpoints and our back office systems and data center. The network interface cards inside smart meters also act as relays (repeaters), further extending the mesh.

The radio frequency mesh network aggregates smart meter data and transmits it to us either through the utility-owned WAN or cellular connection. The mesh network can also transmit other information (such as remote service connects or disconnects) from us to customers. A back office head end system (such as UtilityIQ) collects, measures, and analyzes energy consumption, interval and time-of-use data, power quality measures, status logs and other metering data, and manages smart grid devices. Other back office systems manage meter data and integrate that data with customer and billing information.

Customer Engagement

Although this component represent a small portion of costs of Hawaiian Electric's Smart Grid program, the Hawaiian Electric Companies believe in a proactive, transparent and sustained communication effort to educate and engage our customers is critical to successfully rolling out our smart grid plans. Our efforts to engage our customers underscore our commitment to continually improve customer service, modernize the grid, and integrate renewable energy.

We intend to inform customers about installing smart meters, educate them about smart grid benefits, and address their related concerns. Key to this is helping customers understand that, at its core, smart grid technology will offer them more information about their energy use than ever before and give them tools and programs to help them control their energy use, which they can then use to help lower their electricity bills.

Through a multi-pronged approach for the duration of our smart grid roadmap, we intend to build interest from the onset, address questions and concerns, and engage customers in understanding the benefits of smart grid. Our communication program is based on tested and proven industry best practices, and is customized based on research conducted in this market on how to best reach our customers. Our approach seeks to engage our customers with information tailored to their specific needs and questions. Working with trusted third-party groups, we plan to engage customers in direct conversations wherever they are—at home, in their neighborhoods, and online.

Utility Scale Variable Renewable Generation

The Kahe Utility Photovoltaic (KPV) project will be designed to export up to 11.5MW (AC) of as-available photovoltaic generation to support the goal of reducing the use of fossil fuels and deliver auxiliary station power from a renewable resource.

Replacement Dispatchable Generation Capacity

Schofield

The SGS project will add approximately 50 MW of new flexible generation. The generating station will be capable of load following/peaking/cycling 10-minute reserve capacity generation consisting of six 8.4 MW multi-fuel capable reciprocating engine-generator sets and associated equipment. The project also will provide quick start dispatchable capacity that is capable of being started and fully loaded in 6 minutes or less. The engines will be capable of being individually started and dispatched to provide incremental capacity as needed. The project consists of construction of new generation as well as electrical transmission interties.

The generating station will be located on approximately 5 acres within property owned by the United States Army in Wahiawa, O‘ahu. This property is an undeveloped site with no established infrastructure. The SGS project will include a 2-mile aboveground 46kV transmission line connected to the existing Hawaiian Electric grid.

The project will provide grid-tied, firm, dispatchable, renewable generation to be installed on federal lands for the purpose of ensuring that the Army’s critical national security and first responder missions can be carried on, particularly during events when the utility grid on O'ahu has been compromised, whether through a natural or man-made disaster. The federal lands would be leased at nominal cost from the Army in exchange for the commitment by the utility to construct, operate, maintain, and support the facility.

The electrical output from the SGS generators will normally supply power to all O'ahu customers through the O'ahu electrical grid. However, during outages that meet the criteria specified in an operating agreement with the Army, SGS output may be "islanded" to serve only the Army facilities at Schofield Barracks, Wheeler Army Air Field, and Field Station Kunia.

The SGS project will be capable of using gaseous and liquid fuels. 50% of the fuel used by the SGS engines will be the lowest-cost renewable fuel available at the time and the remainder of the fuel will be the lowest cost fuel available, whether renewable or not. The SGS will include black start capability in the event of a grid outage, allowing the facility to start-up independently, as well as provide black start capability to support the O'ahu grid when necessary.

New Generation

The Commission provided Hawaiian Electric explicit guidance to expeditiously "modernize the generation system to achieve a future with high penetrations of renewable resources." Decision and Order No. 32052, filed April 28, 2014, in Docket No. 2012-0036 (Regarding Integrated Resource Planning), Exhibit A: Commission's Inclinations on the Future of Hawai'i's Electric Utilities (*Commission's Inclinations*) at 4. The Commission recognized that act of "serving load" at all times of the day is becoming less focused on energy provision, and more focused on providing or ensuring the reliability of the grid. Proposed new, flexible generation projects would be a firm generation resource with attributes and optionality consistent with this guidance, including the following abilities:

- Start, synchronize to the grid, and ramp to full load in a few minutes;
- Ramp generation output up and down at fast rates for frequency regulation;
- Operate over a very wide range of loads when synchronized to the gird (that is, more than 12 to 1 turndown);
- Execute multiple starts and stops throughout any operating period;
- Control Volt-Amp Reactive (VAR) output for voltage regulation;
- Provide an automatic inertial response during major grid contingencies to help stabilize system frequency;
- Efficiently convert fuels to electric power (that is, to operate at low heat rates) over its full range of power output;

- Utilize multiple liquid and gaseous fuels; and
- Black start and "island a defined energy district" at a unique location in central O'ahu, adjacent to a major air field.

These attributes will contribute to increased grid stability, security, and resiliency as more variable renewable generation is interconnected.

Retirement of Existing Generation Assets

We will aggressively pursue the retirement and replacement of existing generating units. We deactivated Honolulu units 8 and 9 at the end of January 2014. These units were deactivated but are laid up in a manner that they could be returned to service in an emergency condition. Waiau units 3 and 4 are scheduled for deactivation in 2017. The deactivation of these units allows us to focus our existing resources on our existing units.

We intend to further retire/deactivate steam generating units as new generation and load situations allow. An aggressive plan for deactivation was created and can be adjusted as situations dictate. The plan includes deactivation of all steam units on a systematic basis. In order to provide best value to the customer in terms of cost reduction it was deemed necessary to retire units as a pair. Our unit pairs share one control room, operator staff, and common equipment. In order to maximize cost reduction the unit pair should be retired together.

Units that are scheduled to be deactivated will require capital additions in order to prepare them for deactivation. This allows reactivation should it be required. The plans are very specific and be strictly adhered to in order to be in compliance with the environmental operating permits and regulations.

Use of the Honolulu, Waiau, and Kahe power plant sites after the existing units have been retired is very difficult to predict at this time. The current assumption is that the Waiau and Kahe sites will both have other active utility uses following the projected retirement of the units above, and so those sites are assumed to remain in active utility use.

The Honolulu Power Plant site however, excluding the adjacent substation site, is not anticipated to have a utility use following the retirement of units 8 and 9. While there are many unknowns that will impact both the potential use of this site and the value of the site, including the plans for an adjacent rail station and potential environmental remediation costs, the land is likely to have a net positive value. For the purposes of this financial analysis, it is assumed that the land would be sold in the year following unit retirement for $20M, net of any site remediation costs beyond the demolition and removal of the generating station.

FOUNDATIONAL INVESTMENTS

The success of the transformational investments discussed above is dependent on a strong foundation. The Company must continue to deliver safe, reliable, and efficient service to all customers. The foundational investments required to sustain operations are described below.

Asset Management

The Company has implemented a comprehensive asset management strategy to ensure the performance of the T&D grid. The asset management strategy systematically analyzes the characteristics and performance of each of the grid's major components, including:

- Performance of each major grid component
- Failure modes of each component
- Impact of failure for each component
- Replacement cost for each component

Based on these analyses, the Company has developed and implemented asset management strategies for each major component of the grid to cost effectively sustain the grid's performance over time.

An early assessment of the asset age and historical failure performance at Hawaiian Electric predicted that asset failures would significantly increase in the future unless Hawaiian Electric followed a more intensive approach to managing and replacing aging T&D assets. Failure to increase asset management efforts would result in increasing failures, degradation of electric service to Hawaiian Electric customers and significantly increasing costs as more of the O&M expenses and capital budget are required for corrective maintenance. Asset management (AM) is the process of managing utility assets with a balanced perspective of the company, customers, regulators and employees. It is an integrated set of processes used to minimize life-cycle asset costs while maintaining an acceptable level of risk and continuously delivering reliable service.

Assessing the risk posed by aging and/or problematic assets involves determining the failure probability and potential consequences of in-service failures. Probability of in-service failures is dependent on factors such as operating and maintenance history, but is heavily driven by age for many types of utility equipment. The probability of failure is typically low for most of the equipment's life and then increases dramatically as the equipment nears the end of its average life. As such, when a population of equipment ages the number of failures can increase significantly over time. Potential consequences of in-service failures are usually described in terms of safety, reliability, and cost impacts.

There are various strategies that can be used to address aging and/or problematic assets. These generally include replacing equipment 1) after it has failed in service ("run-to-failure"); 2) prior to failure based on observable indications of imminent failure ("run to imminent failure"); and 3) prior to in-service or imminent failure based on risk posed by the equipment ("preventive replacement"). The optimal strategy or combination of strategies can vary for different categories of equipment depending on factors such as forecasted failures, consequences of in-service failure, condition assessment effectiveness and cost, obsolescence, installation data, and new technology. Furthermore, spare equipment policies are generally developed along with replacement strategies to ensure that an adequate inventory is available when equipment failures do inevitably occur.

Hawaiian Electric's transmission, substation, and distribution infrastructure assets include equipment, such as distribution poles, circuit breakers, substation transformers, underground cable, transmission structures, distribution transformers and switchgear. These assets make up the system that delivers electricity to customers and typically last for many years before they eventually wear out or become obsolete and require replacement. Managing the replacement of aging and/or problematic assets is essential to maintaining the safety of employees and the public as well as the reliability of electric service provided to customers. Summaries of the strategies for these assets follow.

Distribution Poles

There are approximately 60,000 primary and secondary wood distribution poles on the system. The average age of these wood poles is about 40 years (expected life is 40-50 years) while the oldest wood poles on the system are over 90 years old. This is one of Hawaiian Electric's largest and most expansive asset classes. Wood poles in Hawaiian Electric's service area are under constant attack from moisture, insects, fungus, and termites. Approximately 700, or 6%, of the roughly 12,000 wood distribution poles inspected each year are identified as needing to be replaced. The failure rate is expected to increase as a higher number of wood poles reach and surpass the end of their useful life.

The recommendations for this asset class include:

- Continue the Test and Treat program on a five-year cycle to determine pole shell thickness and identify poles that need to be replaced or restored through life extension solutions such as C-Truss or ET-Truss pole reinforcement
- Continue installing "Termi-Mesh" stainless steel barriers to retard termite infestation on all new wood poles installed
- Replace between 1,100 and 1,500 wood distribution poles each year for the next 10 years (2014-2023) and a total of 13,000 poles over the same period

138 kV Circuit Breakers

There are approximately 125 circuit breakers on O‘ahu's transmission system that operate at 138 kV. Of these, there are 47 oil circuit breakers and 78 SF6 gas circuit breakers. The oil circuit breakers range in age from 33 to 52 years old. The average age of these circuit breakers is 42 years while the expected life is around 60 years. The gas circuit breakers range in age from 1 to 29 years old. The average age of these circuit breakers is 15 years while the expected life is around 30 years. The likelihood of failure increases as units approach and exceed their average expected life.

Unexpected circuit breaker failures can potentially result in extended periods of operating the system in an abnormal condition; catastrophic failure and costly replacement of protected and nearby equipment; safety hazards to employees and the public; and major or system wide outages. Since 138 kV circuit breakers have an average procurement cycle of up to 28 weeks, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Continued inspection and maintenance programs
- Identify and replace circuit breakers that are uneconomic to maintain or that are exhibiting characteristics indicative of imminent failure
- Replace a total of, at least, six generator synchronizing breakers during the period form 2014-2016
- Keep on-island spare inventory of four 138 kV circuit breakers

46 kV Circuit Breakers

There are approximately 130 circuit breakers on O‘ahu's transmission system that operate at 46 kV. Of these, there are 62 oil circuit breakers and 68 SF6 gas circuit breakers. The oil circuit breakers range in age from 29 to 71 years old. The average age of these circuit breakers is 51 years while the expected life is around 60 years. The gas circuit breakers range in age from 1 to 27 years old. The average age of these circuit breakers is 8 years while the expected life is around 30 years. The likelihood of failure increases as units approach and exceed their average expected life.

Unexpected circuit breaker failures can potentially result in extended periods of operating the system in an abnormal condition; catastrophic failure and costly replacement of protected and nearby equipment; and safety hazards to employees and the public. Since 138 kV circuit breakers have an average procurement cycle of up to 28 weeks, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Continued inspection and maintenance programs

- Identify and replace circuit breakers that are uneconomic to maintain or that are exhibiting characteristics indicative of imminent failure
- Complete previously planned proactive circuit breaker replacements for 2013 (five OCBs)
- Preventively replace one high-risk capacitor GCB with a "zero crossing" circuit breaker in 2014
- Preventively replace three high-risk line circuit breakers each year from 2014-2023
- Keep on-island spare inventory of three 46 kV line circuit breakers and one 46 kV capacitor bank ("zero crossing") circuit breaker

138 kV Substation Transformers

There are 31 substation power transformers, primarily rated at 138-46 kV 48/80 MVA. The average age of these transformers is about 30 years old while the expected life estimates range from 30 to 60 years. The oldest transformer in this asset category is 52 years old. Failures are forecasted to increase from about one every two years currently to one or more each year by 2019.

Unexpected transformer failures can potentially result in extended outages to customers; extended periods of operating the system in an abnormal condition; potential environmental incidents and expensive cleanup efforts if oil spills from the tank; extended overtime labor to restore the system; damage to nearby equipment in the substation; and a safety hazard to employees and the public. Since these transformers have an average procurement cycle of up to 92 weeks, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Comprehensive inspection and maintenance program intended to maintain or extend the life of the transformers as well as identify and replace transformers exhibiting characteristics indicative of imminent failure
- Preventive replacement of two high-risk transformers in 2013 and one in 2014, then one every other year from 2015 through 2019, and then one each year through 2032
- Keep an on-island spare inventory of two spare 138-46 kV 48/80 MVA transformers to reduce the risk of not having emergency replacements

Distribution Substation Transformers

There are 210 distribution substation power transformers, primarily rated at 46-12 kV, 10 MVA and 12.5 MVA. The average age of these transformers is about 26 years old while the expected life estimates range from 30 to 60 years. The oldest transformer in this asset category is 63 years old. Failures are forecasted to increase from about one every two years currently to one or more each year by 2022.

Unexpected transformer failures can potentially result in extended outages to customers; extended periods of operating the system in an abnormal condition; potential environmental incidents and expensive cleanup efforts if oil spills from the tank; extended overtime labor to restore the system; damage to nearby equipment in the substation; and a safety hazard to employees and the public. Since these transformers have an average procurement cycle of 34-36 weeks, and could take up to 52 weeks in periods of high demand, adequate levels of spares must also be maintained.

The recommendations for this asset class include:

- Comprehensive inspection and maintenance program intended to maintain or extend the life of the transformers as well as identify and replace transformers exhibiting characteristics indicative of imminent failure
- Preventive replacement of three to four high-risk transformers per year going forward
- Keep an on-island spare inventory of two spare 46-12 kV 10/12.5 MVA, 8% impedance transformers and one spare 46-12 kV 10/12.5 MVA, 10% impedance transformer and one transformer that will be used to replace existing 46-12 kV 3.75/5/6.25 MVA transformers to reduce the risk of not having emergency replacements

Primary Underground Cable

There is approximately 4,362 conductor miles of underground primary distribution cable. Of this, about 4,085 conductor miles of this cable is in conduit while about 277 conductor miles of this cable is directly buried in the ground. Cable faults are one of Hawaiian Electric's top two system outage causes and cable faults are forecasted to nearly double in 10 years if only corrective replacements are made during that period. Increasing cable faults can result in decreased reliability and more customers experiencing multiple, often long service interruptions each year.

The recommendations for this asset class include:

- Increase primary underground cable preventive replacement rate, particularly for direct buried cable (increase to rate of 25 conductor miles direct buried cable and 90 conductor miles of cable in conduit per year)
- Continue the current practice of focusing replacements on the worst performing cable with an increased emphasis on customers experiencing multiple interruptions in a year
- Reactively replace paper-insulated lead cable (PILC) when it fails or as part of poorly performing laterals, circuits, or areas targeted for preventive cable replacement

- Collect additional data on cable replacements and cable faults to further refine analysis

138 kV Wood Transmission Structures

There are 374 wood pole transmission structures on 17 of Hawaiian Electric's 28 overhead 138 kV circuits. Wood pole structures make up 29% of all 138 kV transmission structures. The average age of wood pole structures on the 138 kV system is 47 years old while the oldest wood pole structures are 54 years old. Significant portion of Hawaiian Electric's wood pole structures is past or nearing their expected life of 50-55 years. The 138 kV transmission circuits are the backbone of Hawaiian Electric's system and the loss of a transmission circuit could, in the worst case scenario, lead to an island-wide blackout.

The recommendations for this asset class include:

- Continue the Test & Treat program on a 5-year cycle
- Perform energized climbing inspections on all 138 kV structures on a 6-year cycle
- Reactive repair or replacement of structures based on inspections and preliminary engineering and inspection results
- Preventive retirement of structures: At or before the target retirement age of its supported circuit and circuit criticality tier; and up to an additional five structures each year depending on other criticality factors
- Wood pole structures will be retired and replaced with steel pole structures where feasible and in accordance with the Hawaiian Electric Transmission Structural Design Policy

Distribution Transformers

There are over 32,000 distribution transformers installed on Hawaiian Electric's system. These include pad-mounted, pole-mounted, vault, Corten shell enclosed, and submersible transformers. The average age of the asset population is 18 years old while the average expected life is 20 to more than 35 years depending on the transformer type and housing material. About 15 percent, or 4,800, of the in-service distribution transformers were manufactured prior to 1980 and therefore could contain trace amounts of polychlorinated biphenyls (PCBs). In addition, about 248 of the in-service distribution transformers are Corten shell enclosed.

In-service failures of distribution transformers are typically not violent and usually affect only a small number of customers. There is concern about pad-mount transformers failing prematurely or posing safety risks due to corrosion; however, the extent of this issue is unknown as there is no inspection program in place.

In addition, based on EPA guidelines, there are a significant number of "PCB contaminated" (that is, unknown PCB content and pre-1980 manufacture date) transformers. Hawaiian Electric believes, along with other utilities, that regulations will change in the near future requiring removal of "PCB contaminated" equipment by 2025.

Corten shell enclosed transformers have specific operating and reliability issues, but comprise less than one percent of the total distribution transformer population

The recommendations for this asset class include:

- Generally run-to-failure and then replace
- Continue with the practice of using stainless steel construction for all distribution transformers
- Develop and initiate a routine pad-mount transformer inspection program to track the condition
- Preventive replacement of all pre-1980 distribution transformers by the end of 2024
- Preventive replacement of all Corten shell transformers with pad-mounted transformers by the end of 2020

15 kV Switchgear

There are 207 in-service 15 kV switchgear assemblies that house 418 draw-out type circuit breakers. The average age of these switchgears is about 27 years old while the expected life estimates range from 25 to 50 years. The oldest 15 kV switchgear in this asset category is 54 years old. The average age of these circuit breakers is about 23 years old while the oldest circuit breaker is 52 years old. Failures are forecasted to increase from about one every two years currently to one or more each year by 2019. Circuit breakers are, on average, younger than the switchgear assemblies due to the practice of replacing individual circuit breakers prior to replacing the entire switchgear assembly in many instances.

Unexpected switchgear failures can potentially result in extended outages to customers, damage and/or failure of equipment protected, loss of revenue, and, in rare cases, employee injury. Hawaiian Electric has experienced four catastrophic failures of 15 kv switchgear in the last six years resulting in customer interruptions and switchgear damage. The Company also experiences about six circuit breaker failures to trip or close each year due mostly to repeated failures of old breakers and typically resulting in a broader outage or delays in service restoration. Each year Hawaiian Electric replaces about one switchgear due to advanced housing corrosion.

The recommendations for this asset class include:

- Ongoing visual inspections of switchgear assemblies every six months and breaker maintenance every four years
- Continue with the practice of using stainless steel construction and other corrosion-resistant features for all new switchgear
- Preventive replacement of three switchgear assemblies per year through 2015, then six per year through at least 2032
- Switchgear replacements will be implemented in conjunction with replacement of 46-12 kV 10/12.5 MVA substation transformers where appropriate
- Distribution automation enabling of new 15 kV switchgear installations where appropriate
- On-going retention of six on-island 15 kV switchgear assemblies for reactive and preventive replacements

Asset management principles aim to minimize corrective replacement costs, both O&M expense and capital, by implementing preventive strategies. Work performed on a planned basis, in the normal course of business, can usually be executed at lower, more predictable, overall costs and with greater degree of safety to Hawaiian Electric employees and the public. Therefore, following a less aggressive approach would ultimately lead to an increase in cost.

Customer Connections (New Customers)

The Company will need to connect new customers throughout the 2015 – 2030 period. This work includes preparing the design and packaging of customer-requested work, such as overhead and underground services to new and existing customers along with related overhead and underground additions for construction and/or meter installations.

Customer Projects (Existing Customers)

The Company will need to complete customer projects throughout the 2015 – 2030 period.

This category of work includes preparing the design and relocations of services to existing customers for both overhead and underground services. The projects included in this category fall under the baseline category. Note -Fully Funded Customer Projects will not appear since numbers are net of CIAC.

Enterprise

Overview of IT Capital Programs and Enterprise Information Systems

The IT related Capital projects and programs projected in the 2015-2030 Capital forecast consists primarily of two categories:

1. IT Capital programs that support the Companies' hardware lifecycle and growth, broken down by IT function or IT service.
2. Enterprise Information Systems based on the Companies' Enterprise Information Systems (EIS) Roadmap (filed with the commission on 6/13/2014), which includes new software implementations, replacements and upgrades.

This document provides a high level overview of each category and their respective project and programs and the following table provides a view of the projects and programs over the specified timeline.

IT Programs

The ITS Department's capital budget consists primarily of IT hardware programs: (1) that maintain and enhance Hawaiian Electric's data center and network infrastructure; and (2) to provide the workforce with assets that support employee productivity and communications.

These programs are needed to maintain and improve upon IT service levels to both Company stakeholders as well as customers through the lifecycle replacement of hardware assets. In addition, the programs account for increased demand for reliable and secure access to information and information technology, primarily driven by (1) employee and facilities growth; (2) increased investment in mobile computing; (3) escalating need for cyber security and privacy; (4) increased need for enterprise content management; and (5) improved disaster recovery and reliability.

A brief description of each of the IT programs is provided below.

IT Infrastructure program: The IT Infrastructure program is needed to maintain and enhance Hawaiian Electric's data center and network infrastructure and includes costs to lifecycle the server fleet, networking equipment (routers and switches), and electronic storage, as required to meet the Company's business needs. The IT infrastructure program includes "ERP/CIS Hardware Upgrade" 2018-2030 costs (shown separately as an adjustment above for the purposes of this forecast) to accommodate projected replacement and growth specifically for Enterprise Server hardware needs.

Client Computing program: The Client Computing program is needed to provide the workforce with devices and other assets that are managed as part of the client computing environment and support employee productivity and communications. It includes costs to accommodate growth and lifecycle of that environment; including desktop PCs, laptops, mobile devices, and peripherals.

Collaborative Communications program: The Collaborative Communications program includes cost for those hardware assets that enable cost-effective communication and collaboration across time and distance. Specific examples include conferencing enabled telephones, projectors, electronic whiteboards, video conferencing devices, displays, digital signage equipment, microphones and public address (PA) equipment.

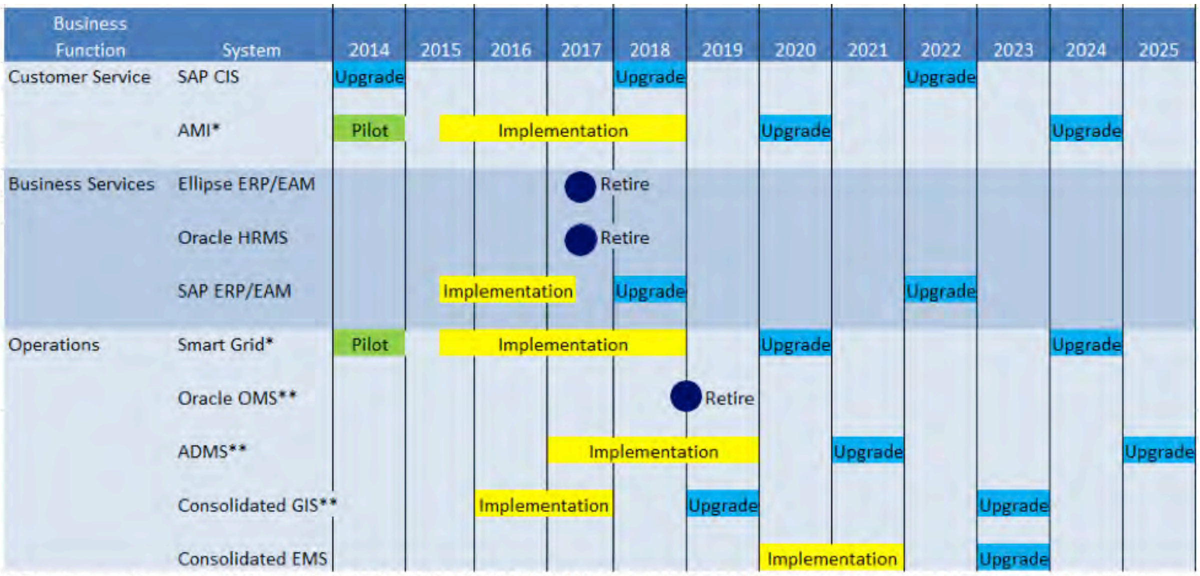
Copiers/Printers: The Copiers/Printers program includes costs to maintain, lifecycle replace, and net new additions for equipment that support the Company's printing and imaging needs. This includes desktop, multi-function, and wide-format printing devices, as well as imaging, scanning and fax devices.

(Miscellaneous) Telephone Equipment: The Telephone equipment program includes costs related to lifecycle and growth of the Company's telephone system including the PBX system, related telephony equipment, and office VOIP and digital phones.

(Miscellaneous) Office Equipment: The Office Equipment program includes costs for lifecycle replacement and installation of new equipment that support the Company mailing operations and general office equipment. Examples include the Company's mail inserter and folding machines used for billing purposes.

Enterprise Information Systems (EIS) Implementation and Upgrade Projects

EIS projects provided in this forecast include projects based on the EIS Roadmap, filed with the commission on 6/13/14.



* This document separates AMI from Smart Grid to reflect the fact that AMI provides customer consumption to customers and to the CIS, while the Smart Grid functions provide Operational capabilities.

** A study is underway to evalute an OMS upgrade or replacement with an ADMS. This document assumes OMS will be replaced by an ADMS. The study also evaluates GIS consolidation and standardizization. This document assumes GIS consolidation. Additional phases for the ADMS and GIS will be added as they are better defined.

Figure K-1. EIS Implementation Plan

The EIS implementation and upgrade projects projected within the Capital forecast are based on the EIS Roadmap with minor adjustments to accommodate the capital forecasting process and adjustment for recent developments. These adjustments include:

1. Projected business releases within the overall GIS and ADMS projects.
2. The inclusion of a Demand Response Management System project.
3. The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle.
4. The "future software implementations" for years 2023 - 30 are based on average spend of years 2015-2022.
5. Smart Grid and AMI explanations will be provided separately, by the Smart Grid project team.

For the purpose of this overview these projects can be viewed in two categories: EIS projects and EIS upgrades. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap. The following overviews are broken out between EIS implementation projects and upgrades.

EIS implementation Projects

ERP/EAM Project: The ERP/EAM project is a major current initiative in the Business Services area of our EIS Roadmap. For a detailed explanation of this project, please reference Dockets 2013-0007 and 2014-0170. The main goals of this effort are to address:

- **Technical Risk:** Replace Ellipse and many workgroup systems with an integrated modern solution. The currently installed Ellipse software and platform is technically obsolete, and continued use of the current version of Ellipse exposes the Companies to rapidly increasing levels of operating risk due to the technical obsolescence of the application software, system software and hardware on which it is dependent. Beyond 2017, there is a significant risk that the Ellipse system will become unsupportable.
- **Vendor Risk:** Implement a solution that is well supported within the utility industry today and into the foreseeable future. There is concern with the long-term vendor commitment to Ellipse. The newest version of Ellipse does not provide the level of electric utility-specific functionality necessary to meet the Companies' key current and future business challenges and opportunities.
- **Business Improvements:** Take the opportunity to improve business processes that increases productivity, efficiency and effectiveness.

EGIS Project: The Geographic Information System (GIS) provides the location of electrical facilities (poles, conductors, transformers, substations, etc.) on a map. It also stores information on how these facilities are connected together to make up the electrical grid. This allows for circuit tracing and allows for the export of this model to other applications such as the Outage Management System (OMS) for outage management and SynerGEE for power flow analysis. This project will migrate from the current multiple instances of different GIS platforms to a single Enterprise GIS solution, across all three companies. This effort includes cleansing and improving the accuracy of the location of electrical facilities.

ADMS Project: The Advanced Distribution Management System (ADMS) project will upgrade and expand the functionality of the current Hawaiian Electric’s Outage Management System (OMS) which is used to determine and track electrical outages and deploys this system to across the three companies. An ADMS is comprised of three foundational features: Outage Management used to track and simulate outages; SCADA integration for receiving status and sending commands to the devices in the electrical grid; and Distribution Management System (DMS) which monitors and controls switching at the distribution level in conjunction with Distribution Automation.

Demand Response Management System: A DRMS provides an integrated management application for managing Demand Response programs and implementing demand response events on the distribution grid. Demand response (DR) balances customers' need for electricity with the utilities' responsibility to successfully operate the system. A well-conceived and well-managed portfolio of demand response programs provides cost-effective and useful ancillary services and capacity for grid operations. DR programs may be implemented by the utilities and/or through 3rd-party administrators.

O'ahu Facilities Capital Expenditures

Ongoing utility operations require efficient and effective business facilities infrastructure to meet customer and workforce needs. O'ahu capital expenditures for facilities are necessary to provide adequate administrative working space, support structures and accommodations for employees to perform their assigned tasks. It includes renovation of existing structures to meet the changing needs of the company and to extend the service life of the structures.

The foundational capital investments required to support these needs include routine investments for building facilities sustenance and a replacement office facility. The office facility investment specifically will replace a large number of office leases, which should result in long-term savings for customers.

Waiau 1 & 2 and Office Building

These buildings need facility improvements for more efficient use of space at the Waiau Power Plant and Waiau Base yard. This project would convert facilities no longer required for their current usage into administrative space, where possible.

Ward Office Renovation

The Ward Avenue building is over 60+ years old and no major renovations have been completed in over 20 years. There have been tremendous growth in technology and the way we need to work and function within our workspace is changing. Upgrading the facilities is essential to facilitating a more functional and productive workspace.

New Warehouse

With the growth in employees, support that goes with the growth also increases. The Ward Base yard is congested with vehicles and warehouse activity and is becoming a safety issue. Plans are to alleviate the congestion by relocating some of the warehouse functions co-located with the base yard off of the Ward property.

System Operation Control Center (SOCC) Facility

A new SOCC facility is planned as a new control center for grid operations. The SOCC is planned to house the new EMS, ADMS, OMS and other grid operating infrastructure In light of recent updates to storm and tsunami maps and greater awareness of man-made threats, the new SOCC design and location will provide enhanced physical security from criminal/terrorist attacks as well as protection from natural disasters.

Office Building

The need for office space has increased with expanded staff and workload. There is no room for growth in the Hawaiian Electric-owned buildings (including power plants and the auxiliary base yards) as currently configured. Hawaiian Electric administrative staff is currently scattered in multiple leased locations: the main King St. Office building, the Central Pacific Bank Building, the American Savings Bank Tower, Pauahi Tower and Pacific Park Plaza. In particular, the main King St. office building is a leased building whose aging infrastructure as a national historic registered building is increasingly costly to maintain. Consolidating our office space currently scattered in different leased buildings will reduce costs, improve return on investment, reduce the existing inefficiencies caused by scattered facilities locations and overcrowding, and result in customer savings.

Reliability

The Reliability category covers projects to ensure that Hawaiian Electric's transmission and Distribution grids are available to accept generation resources and reliably deliver power to customers. A significant component to the Reliability theme includes distribution automation projects and programs. Some of the major programs include Distribution Automation programs, replacement of the Waiau 138kV and 46kV switchyards and substations, rehabilitation of the Halawa 138kV substation, and additional distribution substation projects to provide additional backup and transfer capabilities current loads in specific areas of the island.

Safety, Security, and Environmental

The Safety, Security, and Environmental theme is to ensure that Hawaiian Electric's transmission and distribution facilities and operations are in compliance with applicable environmental, safety and other regulations or, to ensure that such facilities and operations are in line with industry best practices if specific regulations do not exist. For example, related to seabird protection under the Endangered Species and Migratory Bird Treaty Acts, Hawaiian Electric started installing "bird friendly" lighting at Hawaiian Electric's facilities.

Archer Substation 46kv GIS Replacement

The primary purpose of this project is to design and install replacement 46kv GIS equipment at the Archer Substation. There have been serious injuries and fatalities associated with the specific model and vintage of GIS equipment (including serious injury of Hawaiian Electric employees) currently installed at Archer Substation. In addition, the manufacturer has discontinued full support of this line of equipment which will have an impact to the availability and timeliness of parts to support continued operations.

MATS Compliance

Emissions standards set under the toxics program are federal air pollution limits that individual steam power plant facilities must meet by 2016.

FOUNDATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

This section describes the capital investment projects.

Asset Management

Ala Wai Canal 46kV U Relocation

The purpose of this project is to increase the reliability of the Waikiki Substation by permanently relocating the Pukele 5 and Kamoku 43 46kV feeders crossing the Ala Wai Canal to a new alignment along Ala Wai Blvd running from Kapahulu Substation to Waikiki Substation. After the relocation is completed, the existing two 46kv cables can be removed from the canal. State DLNR letter of 9/25/2003 to Hawaiian Electric requires that the cables be permanently relocated.

Kahe Transfer#1 80MVA P/I

The purpose of this project is to retire the existing Kahe 138–46kV, 80 MVA Transformer #1 and purchase and install a new 138–46kV, 48/64/80 MVA transformer to improve the reliability of the transmission system.

Koʻolau Transfer#1 80MVA P/I

Replace existing 138–46kV, 80 MVA Transformer No. 1 and purchase and install a new 138kV 80 MVA transformer. The purpose of this project is to retire the existing Koʻolau 138–46kV 80 MVA Transformer #1 and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Koʻolau Transfer#3 80MVA P/I

The purpose of this project is to retire the existing Koʻolau 138–46kV, 80 MVA Transformer #3 and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Pukele 80MVA Transfer #1

At the Pukele 138kV substation, the Pukele transformer #1 is scheduled to be proactively retired and a new 48/80 MVA transformer will be purchased and installed in its place as part of the Asset Management Plan.

Pukele 80MVA Transfer #2

At the Pukele 138kV substation, the Pukele transformer #1 is scheduled to be proactively retired and a new 48/80 MVA transformer will be purchased and installed in its place as part of the Asset Management Plan.

Wahiawa Transfer#1 80MVA P/I

The purpose of this project is to retire the existing Wahiawa 138–46kV, 80 MVA Transformer #1 and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Waiau Transfer A 80MVA P/I

Retire the existing Waiau 138–46kV 80 MVA Transformer A and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Waiau Transfer B 80MVA P/I

The purpose of this project is to retire the existing Waiau 138–46kV, 80 MVA Transformer B and purchase and install a new 138–46kV, 48/64/80 MVA transformer.

Customer Connections

Kalaeloa Substation

The purpose is to address increasing load demand by installing a new system substation in the Kalaeloa area.

Ph1–Waipahu SS T&D

Install capacity in various substations and T&D facilities to serve the City's Honolulu High Capacity Transit Corridor Project (HHCTCP). These projects are required to serve facilities for the West Oʻahu/Farrington Highway (WOFH) Guideway Segment of the Honolulu Rail Transit Project.

Ph1–Waipahu SS Transfer #3

Install capacity in various substations and T&D facilities to serve the City's Honolulu High Capacity Transit Corridor Project (HHCTCP). These projects are required to serve facilities for the West O'ahu /Farrington Highway (WOFH) Guideway Segment of the Honolulu Rail Transit Project.

Ph2–Pearl City SS T&D

These projects are required to serve facilities for the Kamehameha Highway Guideway Segment (KHG) segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph2–Pearl City SS Transfer #2

These projects are required to serve facilities for the Kamehameha Highway Guideway Segment (KHG) segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph3–Aiea for Stadium TS

These projects are required to serve facilities for the Airport Guideway Segment of the Honolulu Rail Transit Project. The scope of work includes relocation of Hawaiian Electric electrical facilities and installation of distribution infrastructure to serve new facilities for the Rail Transit stations in the Airport Guideway Segment, which runs from Aloha Stadium through Middle Street.

Ph3–Keehi for Airport TS

These projects are required to serve facilities for the Airport Guideway Segment of the Honolulu Rail Transit Project. The scope of work includes relocation of Hawaiian Electric electrical facilities and installation of distribution infrastructure to serve new facilities for the Rail Transit stations in the Airport Guideway Segment, which runs from Aloha Stadium through Middle Street.

Ph3–Lagoon for Lagoon TS

These projects are required to serve facilities for the Airport Guideway Segment of the Honolulu Rail Transit Project. The scope of work includes relocation of Hawaiian Electric electrical facilities and installation of distribution infrastructure to serve new facilities for the Rail Transit stations in the Airport Guideway Segment, which runs from Aloha Stadium through Middle Street.

Ph4–Hon for Chinatown TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph4–Kakaako for Civic TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph4–Kewlo for Ala Moana TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Ph4–Lagoon for Midd St TS

These projects are required to serve new facilities for the City Center Guideway Segment of the Honolulu Rail Transit Project. The purpose of this project is to install a dedicated substation to provide electrical service to meet the estimated loads as requested by the City & County of Honolulu Rapid Transit Authority (HART).

Enterprise IT Framework

ADMS BR1 – OMS Core Functionality Capital

Replaces the current Outage Management System (OMS) at Hawaiian Electric which will become unsupportable in 2016 (based on Hardware/OS losing vendor support). This project also deploys OMS functionality to Maui Electric and Hawaiian Electric Light.

ADMS BR1 – OMS Core Functionality Deferred

Replaces the current Outage Management System (OMS) at Hawaiian Electric which will become unsupportable in 2016 (based on Hardware/OS losing vendor support). This project also deploys OMS functionality to Maui Electric and Hawaiian Electric Light.

Client Computing

The Client Computing program is needed to provide the workforce with devices and other assets that are managed as part of the client computing environment and support employee productivity and communications. It includes costs to accommodate growth and lifecycle of that environment; including desktop PCs, laptops, mobile devices, and peripherals.

ERP/EAM Capital

The ERP/EAM project is a major current initiative in the Business Services area of our Enterprise Information System (EIS) Roadmap. For a detailed explanation of this project, please reference Dockets 2013–0007 and 2014–0170. The main goals of this effort are to address technical risk, vendor risk and business improvements.

ERP/EAM Deferred

The ERP/EAM project is a major current initiative in the Business Services area of our Enterprise Information System (EIS) Roadmap. For a detailed explanation of this project, please reference Dockets 2013–0007 and 2014–0170. The main goals of this effort are to address technical risk, vendor risk and business improvements.

Future software implementations Capital

The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle. The "future software implementations" for years 2023 – 30 are based on average spend of years 2015–2022. This portion is for the hardware component of the anticipated projects. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap.

Future software implementations Deferred

The projection of upgrades through the additional 5 years of the forecast, not accounted for in the EIS roadmap, based on a 4 year average Enterprise Software upgrade cycle. The "future software implementations" for years 2023 – 30 are based on average spend of years 2015–2022. This portion is for the hardware component of the anticipated projects. For a more detailed explanation of strategic and other drivers please reference the EIS roadmap.

IT Infrastructure

The IT Infrastructure program is needed to maintain and enhance Hawaiian Electric's data center and network infrastructure and includes costs to lifecycle the server fleet, networking equipment (routers and switches), and electronic storage, as required to meet the Company's business needs. The IT infrastructure program includes "ERP/CIS Hardware Upgrade" 2018–2030 costs (shown separately as an adjustment above for the purposes of this forecast) to accommodate projected replacement and growth specifically for Enterprise Server hardware needs.

Facilities

Ctrl Baseyard & Warehouse Fac

Construct a new baseyard and warehouse facility to improve T&D operational efficiencies and address future growth in Energy Delivery operations.

New SOCC – Construction

A new SOCC is proposed for the enhancement of operational situation awareness and centralized control existing utility equipment, distributed energy resources and transitional technology systems that will be necessary for the integration of more renewable resources.

New SOCC – Land

A new SOCC is proposed for the enhancement of operational situation awareness and centralized control existing utility equipment, distributed energy resources and transitional technology systems that will be necessary for the integration of more renewable resources.

Waiau 1/2

The need for office space has increased with the growing number of employees. There is no room for growth in Company–owned buildings (including power plants and the auxiliary baseyards) as currently configured. Consolidating our office leases scattered in six different leased buildings will increase operational efficiencies and flexibility for our present and future workforce.

Office Building

The company currently leases a significant amount of administrative (office) space and desires to reduce overall expenditures by purchasing an office building in the future.

Ward Office Renovation

The building is over 60+ years old and no major renovations have been completed in over 20 years. There has been tremendous growth in technology and the way we need to work and function within our workspace is changing. Upgrading the facilities is essential to facilitating a more functional and productive workspace.

New Warehouse

With the growth in employees, support that goes with the growth also increases. The Ward Baseyard is congested with vehicles and warehouse activity and it is becoming a safety issue. Plans are to alleviate the congestion by relocating some of the warehouse functions off of the Ward Baseyard property.

Reliability

46kV Mobile Substation

The purpose of the project is to purchase a 46kV–12kV/4kV Mobile Substation. The objective of this project is to improve reliability of the distribution system.

DA–Smart Tech Install

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Ena

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Kapahulu

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Kuhio

Maintain and improve distribution reliability in the Waikiki area.

Dist Automation–Waikiki

Maintain and improve distribution reliability in the Waikiki area.

Hal Bkr#176,4436,4492 P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa 138kv Expansion

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa 46 kV Bus OH to UG

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Bkr#157–159 138kV P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Bkr#160–162 138kV P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Comm Equipment P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Control House P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Switch Replacements

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Transfer #1 80MVA P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa Transfer #2 80MVA P/I

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Hal–Iwi 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Ko‘olau #1 138 kV Pole Replacement

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Ko‘olau #2 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Ko‘olau #3 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Makiki 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Halawa–Sch 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

New Waiau 46kv Substation

The purpose of this project is to build a new 46kV substation and control house to replace the existing Waiau 46kv Substation. With a new 46kv substation and control house, the reliability of transmitting power to the central O'ahu region will be improved as the existing substation is in need of major upgrades to continue reliable operation.

North South Road 46kV/12kV Ln

To serve for the proposed East Kapolei II Sub–Division, which includes 1,500 residential homes and low density apartment units, the new KROC Center, a new middle school, and a new elementary school. In addition, the project will also provide provisions to service initial loads in the areas surrounding East Kapolei II.

North South Road Communication Links

To serve for the proposed East Kapolei II Sub–Division, which includes 1,500 residential homes and low density apartment units, the new KROC Center, a new middle school, and a new elementary school. In addition, the project will also provide provisions to service initial loads in the areas surrounding East Kapolei II.

North South Road Substation

To serve for the proposed East Kapolei II Sub–Division, which includes 1,500 residential homes and low density apartment units, the new KROC Center, a new middle school, and a new elementary school. In addition, the project will also provide provisions to service initial loads in the areas surrounding East Kapolei II.

Waiau 138KV SS Switch & Steel Replacement

The purpose of this project is to retire and replace severely deteriorated steel frames at Waiau 138 kV substation which support switches and strain bus. The project also includes the replacement of (10) GOAB 138 kV switches.

Waikiki–Halawa #1 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Waikiki–Halawa #2 138 kV Line

The purpose of the Halawa Substation Rehabilitation project is to increase the reliability of the Halawa substation by eliminating 138 kV line crossings in the adjacent area, as well as upgrading the aging substation equipment, relays, controls, and communications.

Safety, Security and Environmental

Archer Substation 46kV GIS Replacement

To design and install replacement 46kV GIS equipment at the Archer Substation. Due to age and recent reliability issues, and availability of parts, the GIS equipment will be replaced.

MATS Compliance

The purpose of the MATS Compliance projects are to provide the necessary upgrades at the Kahe and Waiau Power Plants to support compliance with the EPA's Mercury and Air Toxics Standards (MATS).

TRANSFORMATIONAL CAPITAL INVESTMENT PROJECT DESCRIPTIONS

DG Enabling Investments

DGIP / Distribution Transformers

The DGIP includes a Distribution Circuit Improvement Implementation Plan (DCIIP) that summarizes specific strategies and action plans, including associated costs and schedules, for circuit upgrades and other mitigation measures to increase the capacity of the Companies' electrical grids and enable the interconnection of additional DG. The DGIP also considers prioritization of the proposed mitigation actions to focus on the immediate binding constraints for interconnection of additional DG; analysis of the costs and benefits of proposed mitigation strategies and action plans; discussion of how distribution system design criteria and operational practices could be modified to enable interconnection of additional DG; and proposals for addressing the cost allocation issues that determine who bears responsibility for system upgrade costs.

Technology Demonstration

The Program is structured to evaluate technologies and applications that require field testing, and as such, leverages funding for battery or flywheel systems by outside entities to reduce technical risk. The technical value to field–test grid solutions at the substation level under an aggregated scenario will provide the Companies with operating experience and field data to guide its business decisions related to future commercial implementation.

Liquefied Natural Gas (LNG)

LNG

In an effort to reduce cost of electricity to the customer and comply with requirements of EPA's air regulations, Mercury and Air Toxics Standards (MATS) and National Ambient Air Quality Standards (NAAQS) by displacing liquid petroleum fuel with LNG. The ability to combust liquid petroleum fuel will be retained to enhance the flexibility and reliability of the units.

Pearl Harbor Substation

To install a new 46–12kV distribution substation to serve the future liquefied natural gas (LNG) docking station in Pearl Harbor.

Facilitates New and Renewable Energy

Flexible Operations

The Operational Flexibility Upgrade projects will increase unit operational flexibility in the areas of lower unit minimums, unit dynamic response, improved heat rate at the lower load profiles, minimize equipment degradation, & provide for seasonal cycling operation. These projects will improve equipment and facilities to support Kahe and Waiau power plant unit's operating profile to allow the grid system to accept increased amounts of intermittent renewable energy.

New System 138kV Line

A new 138kV transmission line from Koʻolau Substation to Wahiawa Substation (along the windward, northern, and central areas of the island) would accommodate additional renewable energy in the future on the central and northern areas of Oʻahu. This transmission line would be approximately 55 miles. Currently, no transmission circuits exist on this part of the island.

Replace Dispatch Gen Capacity

Schofield Generating Station

The proposed Schofield Generation Station project would provide about 50 MW of firm quick–start renewable capacity to be built upon Army provided land. The additional capacity will improve system reliability, provide fast start (8–minute) dispatchable capacity, and the large (10–17MW per unit) bio–fueled engines will allow economic dispatch by starting individual units, providing incremental capacity as needed.

Smart Grid and Demand Response

Smart Grid

The Smart Grid Full Implementation Project will 1) install devices in the field, such as meters, remote controllable switches, fault circuit indicators, capacitors, and load controlling switches, 2) install central office software designed to collect information from the field devices and/or then execute commands or tasks by a system operator for the purposes of managing the grid or managing the utilities' meter reading and field services business processes and 3) provide the Hawaiian Electric Companies' customers with tools which enables them to understand and manage their energy use and energy bill. The benefits for implementing the Smart Grid Full Implementation Project is to 1) lower electricity bills through savings and productivity improvements in utility operations, 2) increase renewable energy through integrated distributed generation, 3) provides tools to the customers to enable them to utilize their energy more effectively/efficiently, and 4) increase reliability through outage notification and distribution automation which can lower SAIFI and CAIDI.

Security System Investments

EMS – Capital

A new EMS using a common vendor platform for all utilities will provide operational efficiencies and support flexibility among the three utilities. The new system should be designed to enable future enhancement opportunities to provide backup and emergency support, manage the system changes and growing demands of renewable energy integration, respond and coordinate system emergencies across utilities.

EMS – Deferred

A new EMS using a common vendor platform for all utilities will provide operational efficiencies and support flexibility among the three utilities. The new system should be designed to enable future enhancement opportunities to provide backup and emergency support, manage the system changes and growing demands of renewable energy integration, respond and coordinate system emergencies across utilities.

PSIP Storage Contingency

200 MW battery energy storage system that provides contingency reserve for the grid.

PSIP Storage Load Shift

100MW battery energy storage system that provides regulating reserve for the grid.

TMP – DR Community Projects

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP – Frequent Purchase for Coll Point

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central Waiau Switching Station 46/12kv

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Airport Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Airport Switching Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Archer Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Halawa Baseyard

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Honolulu Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – Makalapa Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central – School Street Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central– Kahe Switching Station (5–8)

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central–Iwilei Sub 138/25

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Center Airport Substation Airport Switch F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – American Savings

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Grosvenor

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Kahe Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Waiau Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core – Ward Avenue

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Aina Koa–Pukele F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Archer–Honolulu Club F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core ASB–CPP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Honolulu Club – King F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core HPP–ASB F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core HPP–Iwiilei138 F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Kahe to CEIP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core Kamoku–Aina Koa F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core King – Ward F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Core King to CPP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Halawa Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Kamoku Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Kewalo Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Koʻolau Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Marketplace to Halawa F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Piʻikoi Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East – Pukule Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East Archer–Pi‘ikoi F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East Kamoku Upper F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP East Pi‘ikoi to Ward F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – AES Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Archer–HPP F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Central Pacific Plaza

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Halawa Control Center

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Honolulu Club Building

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Kalaeloa Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – King Street Office

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Pauahi Tower

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Edge – Waterhouse

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – AES Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – CEIP Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – Chevron

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – CIP Power Plant

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – HRRV

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West – Kalaeloa Substation

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP West Kahe Switching Station (1–4)

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

TMP Central Airport Switch Spl–Airport Substation F/O

To upgrade telecommunications infrastructure to support efficient, secure, and reliable business and utility operations, and to facilitate AMI, Distribution Automation, Smart Grid technologies, and customer programs.

Waiau–Makalapa Fiber Project

To expand the capacity of and provide an alternate route for the fiber optic communications between the Waiau Power Plant and Makalapa Substation. The objective of this project is to maintain and/or improve the reliability of Hawaiian Electric's Communication Infrastructure that supports Hawaiian Electric's Electrical System.

Utility Scale Variable Renewable Generation

K0–Kahe Utility Scale PV

The Kahe Utility Photovoltaic (KPV) project will be designed to export up to 11.5MW (AC) of as–available photovoltaic generation to support the goal of reducing the use of fossil fuels and deliver auxiliary station power from a renewable resource.

CAPITAL EXPENDITURES BY CATEGORY AND PROJECT

Capital Expenditures: 2015–2019

Table K-1 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2015–2019. Table K-2 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2015	2016	2017	2018	2019
Foundational	**313,409,173**	**334,541,490**	**321,205,103**	**371,986,407**	**361,183,387**
Asset Management	120,178,088	141,000,928	158,458,491	172,268,487	152,939,160
Ala Wai Canal 46kV U Relocation	430,776	499,060	174,044	19,231,980	639,627
Kahe Transfer #1 80MVA P/I	–	–	32,679	416,813	3,143,702
Koʻolau Transfer #1 80MVA P/I	–	–	–	773,348	1,066,632
Koʻolau Transfer #3 80MVA P/I	–	–	–	–	–
Pukele 80MVA Transfer #1	3,122,628	–	–	–	–
Pukele 80MVA Transfer #2	40,556	–	–	–	–
Wahiawa Transfer #1 80MVA P/I	–	–	–	–	19,860
Waiau Transfer A 80MVA P/I	116,212	2,722,464	562,973	–	–
Waiau Transfer B 80MVA P/I	–	83,787	1,520,062	1,442,910	608,973
Baseline	116,467,916	137,695,617	156,168,733	150,403,435	147,460,366
Customer Connections	26,416,464	25,557,171	25,578,984	26,078,324	33,382,115
Kalaeloa Substation	–	–	133,227	356,302	9,276,583
Ph1–Waipahu SS T&D	420,645	65,383	–	–	–
Ph1–Waipahu SS Transfer #3	932,513	393,595	–	–	–
Ph2–Pearl City SS T&D	–	3,983	13,886	39,130	–
Ph2–Pearl City SS Transfer #2	–	3,368	7,144	33,072	–
Ph3–Aiea for Stadium TS	–	3,368	7,094	37,993	–
Ph3–Keehi for Airport TS	–	857	1,664	1,641	420
Ph3–Lagoon for Lagoon TS	–	643	1,694	1,636	560
Ph4–Hon for Chinatown TS	–	–	25,272	141,345	55,114
Ph4–Kakaako for Civic TS	–	–	22,334	130,738	68,670
Ph4–Kewlo for Ala Moana TS	–	–	16,457	109,523	95,783
Ph4–Lagoon for Midd St TS	–	1,231	43,310	162,560	14,446
Baseline	25,063,306	25,084,743	25,306,903	25,064,384	23,870,539
Customer Projects	1,907,213	8,338,410	(4,450,772)	2,655,251	1,902,013
Baseline	1,907,213	8,338,410	(4,450,772)	2,655,251	1,902,013

Project	2015	2016	2017	2018	2019
Enterprise IT Framework	29,386,540	32,961,548	12,936,217	14,795,051	12,656,461
ADMS BR1 – OMS Core Functionality Capital	–	–	176,400	–	–
ADMS BR1 – OMS Core Functionality Deferred	–	–	2,381,038	2,562,157	–
Client Computing	2,570,982	2,248,536	2,353,297	2,469,314	2,591,051
ERP/EAM Capital	2,590,000	–	–	–	–
ERP/EAM Deferred	19,300,000	24,710,000	1,140,000	–	–
Future Software Implementations Capital	–	–	–	–	–
Future Software Implementations Deferred	–	–	–	–	–
IT Infrastructure	3,083,983	2,888,867	2,966,061	3,112,288	3,265,724
Baseline	1,841,575	3,114,145	3,919,421	6,651,293	6,799,686
Facilities	8,380,626	6,129,488	6,656,905	7,573,291	10,285,797
Ctrl Baseyard & Warehouse Facility	–	–	–	–	288,776
New SOCC – Construction	–	–	–	–	–
New SOCC – Land	–	–	–	–	–
Waiau ½	–	–	–	–	502,000
Office Building	–	–	–	–	–
Ward Office Renovation	–	–	–	–	–
New Warehouse	–	–	–	–	–
Baseline	8,380,626	6,129,488	6,656,905	7,573,291	9,495,021
Reliability	103,925,059	108,716,252	103,595,899	128,188,790	139,779,311
46kV Mobile Substation	–	2,469,465	–	–	–
DA–Smart Tech Installation	–	735,544	1,099,748	528,744	–
Dist Automation–Ena	–	872,893	1,086,414	332,515	–
Dist Automation–Kapahulu	–	895,170	1,077,050	327,136	–
Dist Automation–Kuhio	–	10,325	40,534	2,197,986	–
Dist Automation–Waikiki	–	858,698	1,107,011	321,100	–
Hal Bkr#176,4436,4492 P/I	–	–	–	–	–
Halawa 138kv Expansion	–	–	–	–	–
Halawa 46 kV Bus OH to UG	–	–	–	–	–
Halawa Bkr#157–159 138kV P/I	–	–	–	–	–
Halawa Bkr#160–162 138kV P/I	–	–	–	–	–
Halawa Comm Equipment P/I	–	–	–	–	–
Halawa Control House P/I	–	–	–	–	–
Halawa Switch Replacements	–	–	–	–	–
Halawa Transfer #1 80MVA P/I	–	–	–	–	–
Halawa Transfer #2 80MVA P/I	–	–	–	–	–
Hal–Iwi 138 kV Line	–	–	–	–	–
Hal–Koo #1 138 kV Pole Repl	–	–	–	–	–

Project	2015	2016	2017	2018	2019
Hal–Koo #2 138 kV Line	–	–	–	–	–
Hal–Koo #3 138 kV Line	–	–	–	–	–
Hal–Mak 138 kV Line	–	–	–	–	–
Hal–Sch 138 kV Line	–	–	–	–	–
New Waiau 46kv Substation	–	–	67,514	4,038,621	16,331,839
North South Rd 46kV/12kV Ln	–	–	–	–	–
North South Rd Comm Links	–	–	–	–	–
North South Rd Substation	–	–	–	–	–
Waiau 138KV SS Sw & Stl Repl	32,409	147,135	2,590,538	2,892,272	1,937,918
Wai–Hal #1 138 kV Line	–	–	–	–	–
Wai–Hal #2 138 kV Line	–	–	–	–	–
Baseline	103,892,650	102,727,023	96,527,089	117,550,417	121,509,554
Safety, Security, and Environmental	23,215,183	11,837,693	18,429,378	20,427,213	10,238,531
Archer Sub 46kV GIS Replace	482,529	724,178	9,606,553	11,688,772	6,080,408
MATS Compliance	14,281,696	1,857,040	–	–	–
Baseline	8,450,958	9,256,475	8,822,825	8,738,441	4,158,122
Transformational	**167,116,018**	**498,596,891**	**249,158,042**	**134,982,423**	**116,057,501**
DG Enabling Investments	18,216,934	20,301,934	3,106,336	2,594,336	2,594,336
DGIP / Distribution Transformers	1,886,934	1,886,934	1,150,311	1,150,311	1,150,311
Baseline	15,840,000	15,840,000	1,444,025	1,444,025	1,444,025
Technology Demonstration	490,000	2,575,000	512,000		
Liquefied Natural Gas (LNG)	19,594,736	87,922,857	72,625,364	–	114,910
LNG	19,594,736	87,922,857	72,625,364	–	–
Pearl Harbor Substation	–	–	–	–	114,910
New and Renewable Energy	13,050,987	16,549,665	19,271,710	38,587,732	36,137,271
Flex Ops	5,649,956	10,843,411	13,285,436	6,966,467	732,341
New System 138kV Line				24,582,365	26,649,580
Baseline	7,401,031	5,706,254	5,986,274	7,038,900	8,755,350
Replace Dispatch Gen Capacity	16,117,138	83,616,273	67,924,068	256,223	–
Schofield Generating Station	16,117,138	83,616,273	67,924,068	256,223	–
Smart Grid and Demand Response	1,924,886	40,865,989	32,962,816	34,217,587	5,578,195
Smart Grid	–	40,865,989	32,962,816	34,217,587	5,578,195
Baseline	1,924,886	–	–	–	–
Security System Investments	52,048,129	249,029,171	53,267,746	59,326,545	71,632,788
EMS – Capital	–	–	–	–	–
EMS – Deferred	–	–	–	–	–
PSIP Storage Contingency	36,860,369	208,875,424	–	–	–
PSIP Storage Load Shift	–	–	–	–	–

Project	2015	2016	2017	2018	2019
TMP – DR Comm Projects	1,034,389	1,151,365	1,131,380	1,102,703	–
TMP – Freq Purch for Coll Pt	601,391	–	–	–	–
TMP Centra WaiauSwStn46/12kv	–	108,204	63,640	234,870	183,643
TMP Central – Airport Sub	–	191,584	112,590	415,746	325,056
TMP Central – Airport Sw Stn	–	221,467	130,096	474,843	375,421
TMP Central – Archer Sub	–	287,559	168,943	624,057	487,729
TMP Central – Halawa Baseyard	–	55,902	32,852	121,235	94,843
TMP Central – Honolulu PP	–	182,578	107,348	396,189	309,828
TMP Central – Makalapa Sub	–	226,357	128,742	490,857	236,015
TMP Central – School St. Sub	–	165,034	96,937	358,104	279,840
TMP Central– KaheSwStn (5–8)	–	106,643	62,615	231,372	180,774
TMP Central–Iwilei Sub 138/25	–	173,255	238,098	659,124	200,314
TMP Cntr ArptSub–Arpt SwF/O	–	389,874	–	–	–
TMP Core – American Savings	246,443	398,065	–	–	–
TMP Core – Grosvenor	57,276	–	–	–	–
TMP Core – Kahe PP	487,682	742,180	–	–	–
TMP Core – Waiau PP	417,890	636,066	–	–	–
TMP Core – Ward Ave	533,608	873,760	–	–	–
TMP Core Aina Koa–Pukele F/O	629,934	693,765	764,394	–	–
TMP Core Archer–Hon Club F/O	211,579	233,018	256,741	–	–
TMP Core ASB–CPP F/O	62,493	68,824	75,831	–	–
TMP Core HonClub – King F/O	179,363	197,539	217,649	–	–
TMP Core HPP–ASB F/O	69,234	76,249	84,012	–	–
TMP Core HPP–Iwiilei138 F/O	313,619	345,398	380,561	–	–
TMP Core Kahe to CEIP F/O	783,981	863,424	951,326	–	–
TMP Core Kamoku–Aina Koa F/O	740,063	815,054	898,032	–	–
TMP Core King – Ward F/O	69,234	76,249	84,012	–	–
TMP Core King to CPP F/O	69,234	76,249	84,012	–	–
TMP East – Halawa Sub	–	–	–	432,169	472,252
TMP East – Kamoku Sub	–	–	–	521,188	569,527
TMP East – Kewalo Sub	–	–	–	223,633	244,374
TMP East – Koolau Sub	–	–	–	290,802	317,773
TMP East – Mklp to Halawa F/O	–	–	–	1,800,997	1,986,620
TMP East – Piikoi Sub	–	–	–	218,192	283,119
TMP East – Pukule Sub	–	–	–	290,802	317,773
TMP East Archer–Piikoi F/O	–	–	–	285,135	310,566
TMP East KmkuUpper F/O	–	–	–	110,058	119,880
TMP East Piikoi to Ward F/O	–	–	–	285,135	310,566

Project	2015	2016	2017	2018	2019
TMP Edge – AES Power Plant	220,149	–	–	–	–
TMP Edge – Archer–HPP F/O	534,759	–	–	–	–
TMP Edge – Central Pac Plza	370,403	–	–	–	–
TMP Edge – Halawa Control Ctr	304,322	–	–	–	–
TMP Edge – HonClub Bldg	370,309	–	–	–	–
TMP Edge – Kalaeloa PP	417,351	–	–	–	–
TMP Edge – King St. Office	446,017	–	–	–	–
TMP Edge – Pauahi Tower	220,149	–	–	–	–
TMP Edge – Waterhouse	212,301	–	–	–	–
TMP West – AES Sub	–	–	–	328,062	358,490
TMP West – CEIP Sub	–	–	–	296,409	323,901
TMP West – Chevron	–	–	–	231,552	253,028
TMP West – CIP Power Plant	–	–	–	195,206	362,076
TMP West – HRRV	–	–	–	231,552	253,028
TMP West – Kalaeloa Sub	–	–	–	220,776	241,251
TMP West Kahe Sw Stn (1–4)	–	–	–	220,776	241,251
TMPCtrl ArptSwSpl–ArptSubF/O	–	651,281	–	–	–
Waiau–Makalapa Fiber Project	–	–	2,615,958	2,887,118	3,180,540
Baseline	5,584,587	30,146,804	44,581,978	45,147,883	58,813,310
Utility Scale Variable Renew Gen	46,163,207	311,001	–	–	–
K0–Kahe Utility Scale PV	46,163,207	311,001	–	–	–
Grand Totals	**480,525,190**	**833,138,381**	**570,363,144**	**506,968,830**	**477,240,888**

Table K-1. Capital Expenditures by Category and Project: 2015–2019

Capital Expenditures: 2020–2030 with Project Totals

Table K-2 lists the budgeted, annualized dollar amount for each project; with totals by project group and by category, for the years 2020–2030 with project totals.

Project	2020	2021–2025	2026–2030	Totals
Foundational	**386,426,502**	**1,351,966,232**	**1,173,728,925**	**4,614,447,219**
Asset Management	**101,614,836**	**183,684,838**	**201,170,403**	**1,231,315,232**
Ala Wai Canal 46kV U Relocation	–	–	–	20,975,487
Kahe Transfer #1 80MVA P/I	605,621	114,504	–	4,313,319
Ko'olau Transfer #1 80MVA P/I	1,332,691	–	–	3,172,671
Ko'olau Transfer #3 80MVA P/I	–	3,916,918	–	3,916,918
Pukele 80MVA Transfer #1	–	–	–	3,122,628
Pukele 80MVA Transfer #2	–	–	–	40,556
Wahiawa Transfer #1 80MVA P/I	89,587	3,849,008	–	3,958,455
Waiau Transfer A 80MVA P/I	–	–	–	3,401,649
Waiau Transfer B 80MVA P/I	–	–	–	3,655,732
Baseline	99,586,937	175,804,408	201,170,403	1,184,757,815
Customer Connections	**25,828,652**	**125,931,448**	**141,463,777**	**430,236,936**
Kalaeloa Substation	1,865,529	–	–	11,631,641
Ph1–Waipahu SS T&D	–	–	–	486,028
Ph1–Waipahu SS Transfer #3	–	–	–	1,326,108
Ph2–Pearl City SS T&D	–	–	–	56,999
Ph2–Pearl City SS Transfer #2	–	–	–	43,584
Ph3–Aiea for Stadium TS	–	–	–	48,455
Ph3–Keehi for Airport TS	–	–	–	4,582
Ph3–Lagoon for Lagoon TS	–	–	–	4,533
Ph4–Hon for Chinatown TS	–	–	–	221,731
Ph4–Kaka'ako for Civic TS	–	–	–	221,742
Ph4–Kewlo for Ala Moana TS	–	–	–	221,763
Ph4–Lagoon for Midd St TS	–	–	–	221,547
Baseline	23,963,123	125,931,448	141,463,777	415,748,223
Customer Projects	**2,404,664**	**916,164**	**1,016,824**	**14,689,767**
Baseline	2,404,664	916,164	1,016,824	14,689,767
Enterprise IT Framework	**10,808,064**	**72,139,227**	**91,171,890**	**276,854,997**
ADMS BR1 – OMS Core Functionality Capital	–	–	–	176,400
ADMS BR1 – OMS Core Functionality Deferred	–	–	–	4,943,195
Client Computing	2,718,790	15,741,639	20,023,884	50,717,493
ERP/EAM Capital	–	–	–	2,590,000

Project	2020	2021–2025	2026–2030	Totals
ERP/EAM Deferred	–	–	–	45,150,000
Future Software Implementations Capital	–	390,600	651,000	1,041,600
Future Software Implementations Deferred	–	10,555,848	17,593,080	28,148,928
IT Infrastructure	3,426,724	19,840,535	25,237,814	63,821,994
Baseline	4,662,550	25,610,606	27,666,113	80,265,388
Facilities	**98,932,724**	**272,819,831**	**50,353,638**	**461,132,301**
Ctrl Baseyard & Warehouse Facility	994,500	112,641,963	–	113,925,238
New SOCC – Construction	–	42,141,729	–	42,141,729
New SOCC – Land	–	8,000,000	–	8,000,000
Waiau ½	41,000	36,105,000	–	36,648,000
Office Building	90,000,000	–	–	90,000,000
Ward Office Renovation	–	10,000,000	–	10,000,000
New Warehouse	–	15,000,000	–	15,000,000
Baseline	7,897,224	48,931,140	50,353,638	145,417,334
Reliability	**142,105,863**	**677,003,859**	**671,405,536**	**2,074,720,569**
46kV Mobile Substation	–	–	–	2,469,465
DA–Smart Tech Installation	–	–	–	2,364,036
Dist Automation–Ena	–	–	–	2,291,821
Dist Automation–Kapahulu	–	–	–	2,299,357
Dist Automation–Kuhio	–	–	–	2,248,845
Dist Automation–Waikiki	–	–	–	2,286,809
Hal Bkr#176,4436,4492 P/I	45,233	23,553	93,176	161,962
Halawa 138kv Expansion	351,218	4,485,872	11,617,888	16,454,978
Halawa 46 kV Bus OH to UG	91,262	2,014,868	–	2,106,131
Halawa Bkr#157–159 138kV P/I	50,720	57,625	619,524	727,869
Halawa Bkr#160–162 138kV P/I	50,338	163,446	2,911,495	3,125,279
Halawa Comm Equipment P/I	187,083	3,177,291	99,769	3,464,143
Halawa Control House P/I	160,365	8,238,472	8,897,309	17,296,146
Halawa Switch Replacements	90,708	41,144	2,006,231	2,138,083
Halawa Transfer #1 80MVA P/I	114,798	51,059	3,010,761	3,176,618
Halawa Transfer #2 80MVA P/I	115,968	51,282	2,870,000	3,037,250
Hal–Iwi 138 kV Line	76,110	523,194	4,880,123	5,479,427
Hal–Koo #1 138 kV Pole Repl	88,862	1,018,629	3,219,330	4,326,821
Hal–Koo #2 138 kV Line	67,541	217,742	3,306,923	3,592,206
Hal–Koo #3 138 kV Line	66,248	40,336	547,411	653,995
Hal–Mak 138 kV Line	81,766	599,730	5,059,764	5,741,260
Hal–Sch 138 kV Line	79,508	452,859	5,066,546	5,598,913
New Waiau 46kv Substation	23,158,240	18,822,860	–	62,419,074

Project	2020	2021–2025	2026–2030	Totals
North South Rd 46kV/12kV Ln	–	4,597,597	150,390	4,747,987
North South Rd Comm Links	–	1,082,590	84,997	1,167,587
North South Rd Substation	–	7,800,314	357,864	8,158,178
Waiau 138KV SS Sw & Stl Repl	–	–	–	7,600,271
Wai–Hal #1 138 kV Line	83,698	85,449	739,143	908,290
Wai–Hal #2 138 kV Line	82,188	343,126	5,424,619	5,849,933
Baseline	117,064,009	623,114,820	610,442,274	1,892,827,836
Safety, Security, and Environmental	**4,731,698**	**19,470,865**	**17,146,856**	**125,497,417**
Archer Sub 46kV GIS Replace	–	–	–	28,582,439
MATS Compliance	–	–	–	16,138,736
Baseline	4,731,698	19,470,865	17,146,856	80,776,241
Transformational	**141,097,180**	**389,993,945**	**129,549,616**	**1,826,551,615**
DG Enabling Investments	**2,594,336**	**68,294,431**	**68,294,431**	**185,997,075**
DGIP / Distribution Transformers	1,150,311	4,050,031	4,050,031	16,475,175
Baseline	1,444,025	64,244,400	64,244,400	165,944,900
Technology Demonstration		–	–	3,577,000
Liquefied Natural Gas (LNG)	**6,527,129**	**10,985**	**–**	**186,795,981**
LNG	–	–	–	180,142,958
Pearl Harbor Substation	6,527,129	10,985	–	6,653,024
New and Renewable Energy	**36,789,498**	**106,218,131**	**43,377,682**	**309,982,676**
Flex Ops	–	–	–	37,477,611
New System 138kV Line	28,890,521	65,273,327	–	145,395,793
Baseline	7,898,977	40,944,804	43,377,682	127,109,272
Replace Dispatch Gen Capacity	**–**	**–**	**–**	**167,913,702**
Schofield Generating Station	–	–	–	167,913,702
Smart Grid and Demand Response	**5,090,373**	**28,752,932**	**10,167,351**	**159,560,130**
Smart Grid	5,090,373	28,752,932	10,167,351	157,635,244
Baseline	–	–	–	1,924,886
Security System Investments	**90,095,844**	**186,717,466**	**7,710,153**	**769,827,843**
EMS – Capital	802,700	1,304,387	802,700	2,909,786
EMS – Deferred	4,000,000	11,200,000	–	15,200,000
PSIP Storage Contingency	–	–	–	245,735,793
PSIP Storage Load Shift	18,964,743	107,466,877	–	126,431,620
TMP – DR Comm Projects	–	–	–	4,419,836
TMP – Freq Purch for Coll Pt	–	–	–	601,391
TMP Central WaiauSwStn46/12kv	–	–	–	590,357
TMP Central – Airport Sub	–	–	–	1,044,977
TMP Central – Airport Sw Stn	–	–	–	1,201,826

Project	2020	2021–2025	2026–2030	Totals
TMP Central – Archer Sub	–	–	–	1,568,288
TMP Central – Halawa Baseyard	–	–	–	304,832
TMP Central – Honolulu PP	–	–	–	995,943
TMP Central – Makalapa Sub	–	–	–	1,081,971
TMP Central – School St. Sub	–	–	–	899,914
TMP Central– KaheSwStn (5–8)	–	–	–	581,405
TMP Central–Iwilei Sub 138/25	–	–	–	1,270,791
TMP Cntr ArptSub–Arpt SwF/O	–	–	–	389,874
TMP Core – American Savings	–	–	–	644,508
TMP Core – Grosvenor	–	–	–	57,276
TMP Core – Kahe PP	–	–	–	1,229,861
TMP Core – Waiau PP	–	–	–	1,053,956
TMP Core – Ward Ave	–	–	–	1,407,368
TMP Core Aina Koa–Pukele F/O	–	–	–	2,088,093
TMP Core Archer–Hon Club F/O	–	–	–	701,338
TMP Core ASB–CPP F/O	–	–	–	207,147
TMP Core HonClub – King F/O	–	–	–	594,551
TMP Core HPP–ASB F/O	–	–	–	229,495
TMP Core HPP–Iwiilei138 F/O	–	–	–	1,039,578
TMP Core Kahe to CEIP F/O	–	–	–	2,598,731
TMP Core Kamoku–Aina Koa F/O	–	–	–	2,453,149
TMP Core King – Ward F/O	–	–	–	229,495
TMP Core King to CPP F/O	–	–	–	229,495
TMP East – Halawa Sub	475,800	–	–	1,380,221
TMP East – Kamoku Sub	573,803	–	–	1,664,518
TMP East – Kewalo Sub	246,209	–	–	714,216
TMP East – Koʻolau Sub	320,159	–	–	928,734
TMP East – Mklp to Halawa F/O	–	–	–	3,787,618
TMP East – Piʻikoi Sub	97,748	–	–	599,059
TMP East – Pukule Sub	320,159	–	–	928,734
TMP East Archer–Piikoi F/O	–	–	–	595,701
TMP East KmkuUpper F/O	–	–	–	229,939
TMP East Piʻikoi to Ward F/O	–	–	–	595,701
TMP Edge – AES Power Plant	–	–	–	220,149
TMP Edge – Archer–HPP F/O	–	–	–	534,759
TMP Edge – Central Pac Plza	–	–	–	370,403
TMP Edge – Halawa Control Ctr	–	–	–	304,322
TMP Edge – HonClub Bldg	–	–	–	370,309

Project	2020	2021–2025	2026–2030	Totals
TMP Edge – Kalaeloa PP	–	–	–	417,351
TMP Edge – King St. Office	–	–	–	446,017
TMP Edge – Pauahi Tower	–	–	–	220,149
TMP Edge – Waterhouse	–	–	–	212,301
TMP West – AES Sub	361,183	–	–	1,047,736
TMP West – CEIP Sub	326,333	–	–	946,643
TMP West – Chevron	254,929	–	–	739,508
TMP West – CIP Power Plant	295,836	–	–	853,118
TMP West – HRRV	254,929	–	–	739,508
TMP West – Kalaeloa Sub	243,063	–	–	705,089
TMP West Kahe Sw Stn (1–4)	243,063	–	–	705,089
TMP Ctrl ArptSwSpl–ArptSubF/O	–	–	–	651,281
Waiau–Makalapa Fiber Project	–	–	–	8,683,616
Baseline	62,315,186	66,746,202	6,907,454	320,243,405
Utility Scale Variable Renew Gen	**-**	**-**	**-**	**46,474,208**
K0–Kahe Utility Scale PV	–	–	–	46,474,208
Grand Totals	**527,523,682**	**1,741,960,177**	**1,303,278,541**	**6,440,998,833**

Table K-2. Capital Expenditures: 2020–2030 with Project Totals

L. Preferred Plan Development

The Preferred Plan was developed within a, highly analytical, and innovative process. These elements were critical in developing the Preferred Plan. Collaboration between power system planners, consultants, domain experts, and Hawaiian Electric leadership was critical in maintaining focus, gaining insights, and meeting the challenge of encouraging independent thinking while maintaining common purpose. Best-of-class analytics were used to construct and evaluate complex plans within a number of contexts: feasibility, costs, risks, flexibility, and sustainability. While analytics are the centerpiece of the effort, it was critical to incorporate our strategic vision in the search for innovative ways to implement and leverage energy storage and renewable variable energy sources.

The planning process leveraged the expertise of three modeling teams, using three different models, to address simulation requirements. One purpose of utilizing three teams was to gain confidence in the final recommendation by seeing if different models and approaches provided similar, reinforcing results. This outcome has been realized. The second purpose has turned out to be more critical to planning efforts. Collaboration between the three teams to develop and share theories or options for improvement of the power supply plans, based on incremental results, proved invaluable.

Collectively, the teams worked together to move from concept, through refinement, to definition of the preferred plan.

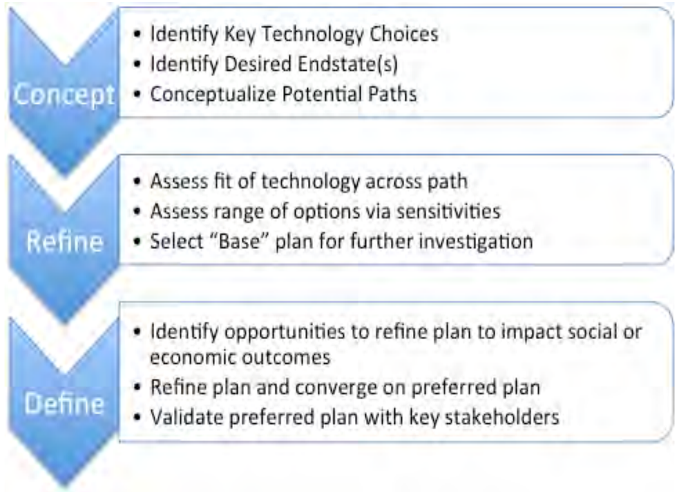


Figure L-1. Process for Developing the Preferred Plan

The analysis focused on transforming today's system into an electrical system that safely and securely integrates various sources of renewable energy by 2030. The analysis was carried out in three major steps:

1. **Develop a Base Plan.** In the first phase, a Base Plan was constructed to meet the primary goal of renewing the system by replacing the existing units with more flexible and responsive units that also met the capacity planning criteria.
2. **Perform Sensitivity Analyses.** Sensitivity analyses were then performed to the Base Plan to test various changes to the plan.
3. **Use Sensitivity Results to Develop the Preferred Plan.** The results of the sensitivity analyses were reviewed and used to develop the Preferred Plan.

Actions taken now and projects developed in next five years will have a strong effect on possibilities in the future. Therefore, great care was taken to develop a Preferred Plan that is flexible enough to accommodate emerging green technology options that become commercially ready in the future. The Preferred Plan positions Hawaiian Electric to address both current and emerging technology options.

METHODOLOGY FOR DEVELOPING THE PREFERRED PLAN

The PSIP planning teams constructed and evaluated a number of strategy canvases to feed a more granular and complex process that vetted technology options. Development of the Preferred Plan was driven by the following concepts:

- Focus on maximizing renewable content – of all types as feasible given specifics of each island while evaluating the economic impacts.

- Develop a grid that can manage large volumes of variable generation; define a technology strategy that allows this capability to evolve over time.
- Utilize conventional, dispatchable thermal assets to provide firm generation and regulation; utilize LNG to improve fuel supply economics and reduce CO_2 emissions.
- Maintain safety and reliability by assuring grid stability needs are met and can keep pace with increasing variability of major generation sources – making energy storage a centerpiece of the strategy.

The modeling teams focused on constructing tactical plans to identify specific steps required to transition from current state to future state. This was a complex and iterative process. Plans were broken down into a series of annual capital project/retirement plans; each plan was verified against system security reliability requirements. Operations of the system within each annual plan was carried out by detailed production simulation models that commit and dispatch assets, manage regulation, and utilize energy storage systems (ESS) or other asset to address variability of solar or wind generation potential, and consider demand response options. As discussed further in Appendix C, these models apply detailed hourly and sub-hourly dispatch models to clarify how to best utilize and value generation or regulation options. While the three different production simulation models employ somewhat different algorithms to simulate power system operations, all of the models are based on electric utility planning and operating practices accepted throughout the world.

The planning process leveraged three models and three modeling teams to address simulation requirements. Collectively, the teams worked together to move the plan from concept, through refinement, to definition of the preferred plan. Specific milestones within the planning process included:

- Test and validate potential 2030 scenarios and technology options to validate the long-term vision captured in the central strategy
- Identification of key success factors or critical technology investments underpinning the 2030 strategy (i.e., diversification of renewables, early adoption of advanced battery for contingency and regulation, LNG supply for thermal assets).
- Validation of the supply mix and roles between variable renewables, dispatchable renewables, and thermal assets to address spin/regulation; this mix defines the degree to which variable assets can be leveraged.
- Optimization of the thermal portfolio based on requirements during each of year of the study period; identify blend of fast start/fast response and more efficient combined cycle technologies against demand and retirement schedules and identify intrinsic value of shifting retirement dates.

- Identify and test alternate technology mixes, timing, and other pros & cons via sensitivity analysis.
- Expand sensitivity analysis into areas of key interest. This varied by island. For O‘ahu - degree of solar and additional wind to increase RPS; for Maui - cost containment/operational improvements enabled by select energy storage and renewable projects, and for the Big Island - economic viability of further expanding wind and/or geothermal footprints.
- Identify preferred plan based sensitivities; verification of plan outcomes by all three models and modeling teams.

System reliability requirements for regulating and contingency reserves were met through a variety of resources including demand response, energy storage, and thermal generation. As increasing amounts of renewable variable generation were added to the system, the system reliability requirements changed annually to reflect the new generation mix.

Sub-hourly models were deployed during the course of the analysis to verify understanding of ESS, demand response, and thermal asset use within short (5-min) increments. Results were compared to hourly models to identify whether substantial changes to operations would be expected; sub-hourly models demonstrated need for and value of balancing variable resources with sufficient ESS and regulating reserve from thermal units.

In constructing and validating the Preferred Plan, the last step in the process involved broader participation of domain experts to fully vet the plan and identify any remaining issues to be addressed. This allowed collective model teams to better assure that models were consistent with operational realities and that plan objectives were met.

Base Plan

The Base Plan seeks to maximize the amount of variable renewable generation that can be accepted on the existing system and creates the flexibility to accommodate additional renewable energy in the future.

In the near term, various system changes are incorporated to improve the flexibility of the existing generation. This operational flexibility is achieved through modifications to existing utility and Independent Power Producer (IPP) generation, specifically by lowering unit minimums and enabling a change in operational modes from base load to cycling. The base plan also included assumptions regarding which units would be converted to LNG fuel. These changes were incorporated into the simulation models.

Utility Generation

- Kahe Units 1-5 and Waiau Units 7 & 8 are enabled to operate at lower unit minimums in 2016
- Kahe Units 1 - 4 will be allowed to cycle but will incur an O&M cost for each start by 2016
- All existing utility generation will fuel switch to LNG in 2017 (except CIP CT-1)

Kalaeloa Energy Partners (KPLP)

- KPLP will fuel switch to LNG in 2017
- KPLP will change operation from dual train combined cycle to a single train combined cycle and run one CT in simple cycle mode

AES

- AES will continue beyond the end of its current contract in 2022 but at a reduced capacity of 90 MW

Future Utility/IPP Generation

- Schofield is in service in 2018
- Na Pua Makani is in service in 2016
- Mililani South Solar Park is in service in 2017
- Waiver projects in service in 2017

To transition from our current state to the 2030 vision, the Base Plan deactivates and retires existing generation based on a retirement schedule starting in 2022. This year was chosen based on the timeframe to acquire new firm generation through the a competitive procurement process which is estimated as approximately 6–7 years for new generation to be installed. New flexible combustion turbines are added to the system to satisfy the capacity planning criteria based on the deactivation schedule. Units are retired (decommissioned) two years after deactivation. Note, the deactivation schedule was tested through modeling of different scenarios so the schedule in the Preferred Plan was not assumed, but validated as part of the overall plan.

New flexible combustion turbines are installed that can cycle off daily and ramp quickly. These units provide the ramping capabilities and regulating reserves required to support increasing PV and wind resources on the system in addition to the ancillary services provided by demand response, energy storage, and variable generation.

Utility deactivation of existing generation:

- Waiau 3 & 4 in 2017
- Waiau 5 & 6 in 2028
- Waiau 7 & 8 in 2030

- Kahe 1 & 2 in 2023
- Kahe 3 & 4 in 2024
- Kahe 5 & 6 in 2022

New generation:

- 285 MW in 2022
- 190 MW in 2023
- 95 MW in 2024
- 95 MW in 2030

Sensitivity Analyses

Sensitivity analyses will be performed on the Base Plan to demonstrate the effect of various changes to the system. The sensitivity analyses evaluated the following on O‘ahu:

AES

- AES at 180 MW using coal
- AES at 180 MW using coal with 100 MW load shifting battery energy storage
- AES at 90 MW using biomass
- AES at 180 MW using 50% biomass and 50% coal

CIP CT-1

- Convert to LNG
- Continue to use biodiesel with contract minimum
- Continue to use biodiesel with economic dispatch and no fuel contract minimum

Waiau 9 & 10 Fuel Use

Additional Renewable Energy Resources

- Include additional 50 MW of wind on O‘ahu
- Include additional 250 MW of utility-scale PV on O‘ahu
- Include additional 150 MW of utility-scale PV on O‘ahu
- Include additional 50 MW wind and 150 MW of utility-scale PV on O‘ahu

Pumped Storage Hydro

- Without increasing PV levels above the Base Plan
- With increasing PV levels above the Base Plan

Future Firm Generation Mix

Sensitivity analyses were performed to test how a particular condition would affect the Base Plan and whether it should be considered for incorporation into the Preferred Plan. The analyses were conducted by the three independent modeling teams (Hawaiian Electric, Black & Veatch, and PA Consulting) and the results are described in this appendix.

Existing Generating Units

The Base Plan included some assumptions that warranted sensitivity analyses to test their robustness. The sensitivity analyses to test the future of existing generating units include:

- AES PPA
- CIP CT-1
- Waiau 9 & 10

AES

The existing PPA with AES expires in 2022. In the Base Plan, we assumed a new power purchase agreement (PPA) would become effective after 2022, but the output from AES would be reduced to a maximum of 90 MW in order to minimize baseload generation in an effort to accommodate more variable renewable generation. Sensitivity analyses performed on this AES assumption varied the capacity and fuel source for this generating unit.

AES at 180 MW using coal

This sensitivity analysis looked at the effect of continuing AES at their current 180 MW rating beyond the contract expiration in 2022. Energy and capacity payments to AES continued to use the current contract formula. The analysis showed that AES continuing at 180 MW using coal decreased the overall system cost compared to the Base Plan. However, AES did not contribute to RPS under this assumption so this was not included in the Preferred Plan.

AES at 180 MW using coal with 100 MW load shifting battery energy storage

This sensitivity analysis assumed that the increased curtailment that occurs when AES continues at 180 MW (instead of 90 MW) is mitigated by a load shifting battery energy storage. The energy storage accepts curtailed renewable energy from the day and discharges during the evening peak. In addition to reducing daytime curtailment, the load shifting battery provides firm capacity during the evening peak and replaces the need for a future 100 MW combustion turbine. The analysis showed that continuing AES at 180 MW using coal and including a 100 MW load shifting energy storage resulted in some cost savings compared to the Base Plan. However, this did not increase the RPS so this AES configuration was not favorable compared to other options and was not included in the Preferred Plan.

AES at 90 MW using biomass

This sensitivity analysis assumed that AES continues at 90 MW using biomass to evaluate the benefit of using a renewable fuel on a baseloaded unit. The analysis showed that continuing AES at 90 MW on biomass increased the RPS. However, the overall system costs compared to the Base Plan increased significantly so this assumption was not included in the Preferred Plan.

AES at 180 MW using 50% biomass and 50% coal

Considering the results of the sensitivity analyses with AES at 180 MW and the benefit of using a renewable fuel source, this sensitivity analysis combined the biomass with coal to create a lower cost, moderately renewable fuel. The analysis showed that continuing AES at 180 MW using a 50% biomass and 50% coal fuel blend increased the overall system costs compared to the Base Plan but increased the RPS significantly so this assumption was included in the Preferred Plan.

CIP CT-1

In the Base Plan, we assumed that CIP CT-1 would use ULSD from 2018 after the current biodiesel fuel contract ends. Sensitivities around the CIP CT-1 assumption varied the fuel source and contract minimum for this generating unit.

Convert to LNG

This sensitivity analysis assumed that CIP CT-1 converts to LNG. The analysis showed that converting CIP CT-1 to LNG increased the overall system costs compared to the Base Plan and did not increase the RPS. This assumption was not included in the Preferred Plan.

Continue to use biodiesel with contract minimum

This sensitivity analysis assumed that CIP CT-1 continues on biodiesel with a contract minimum to burn 3 million gallons per year. The analysis showed that continuing CIP CT-1 on biodiesel with a fuel minimum increased the overall system costs compared to the Base Plan and did not increase the RPS significantly so this assumption was not included in the Preferred Plan.

Continue to use biodiesel with economic dispatch and no fuel contract minimum

This sensitivity analysis assumed that CIP CT-1 continues on biodiesel but is allowed to economically dispatch to meet system load. The analysis showed that economically dispatching CIP CT-1 on biodiesel increased the overall system costs compared to the

Base Plan and did not increase the RPS significantly so this assumption was not included in the Preferred Plan.

Waiau 9 & 10

In the Base Plan, we assumed that Waiau 9 & 10 would be converted to use LNG. This sensitivity analysis looked at not converting to LNG and instead, using ULSD in the units. The analysis showed that using ULSD in Waiau 9 & 10 decreased the overall system costs compared to the Base Plan and was included in the Preferred Plan.

Additional renewable energy resources

The Base Plan includes known renewable energy projects already in the pipeline such as the Schofield Generating Station, Kahe solar, waiver PV projects, Mililani South Solar Park, and Na Pua Makani wind. Sensitivity analyses looked at the effect of adding additional renewable energy resources such as:

- Wind
- Utility-scale PV
- Wind and Utility-scale PV

Wind

This sensitivity analysis added 50 MW of wind on O'ahu. An additional 50 MW of wind increased the overall system costs compared to the Base Plan and increased the RPS. This assumption was further evaluated in other sensitivities for inclusion in the Preferred Plan.

Utility-Scale PV

With the transformation to reduce baseload generation in the Base Plan, sensitivity analyses were performed to test the effect of additional utility-scale PV on a more flexible system.

Additional 250 MW

This sensitivity analysis added 250 MW of utility-scale PV on O'ahu. An additional 250 MW of utility-scale PV increased the overall system costs compared to the Base Plan and increased the RPS. This assumption was further evaluated in other sensitivities for inclusion in the Preferred Plan.

Additional 150 MW

This sensitivity analysis added 150 MW of utility-scale PV on O'ahu. An additional 150 MW of utility-scale PV increased the overall system costs compared to the Base Plan and increased the RPS. This assumption was further evaluated in other sensitivities for inclusion in the Preferred Plan.

Wind and Utility-Scale PV

The sensitivity analyses showed that incremental additions of wind and utility-scale PV could be integrated into the system. This analysis combined the addition of 50 MW of wind and 150 MW of utility-scale PV for more resource diversity. The analysis showed that adding 50 MW of wind and 150 MW of utility-scale PV increased overall system costs compared to the Base Plan but increased the RPS. As a result this analysis, a mix of additional renewable resources was included in the Preferred Plan.

Pumped Storage Hydro

The pumped storage hydro has operating characteristics similar to a load shifting battery energy storage. This resource was assumed to provide firm capacity that can defer future generation and reduce curtailment by accepting curtailed renewable energy during the day to be discharged at the evening peak. Sensitivity analyses were conducted to examine the effect of adding a pumped storage hydro resource on the system.

- 100 MW Pumped Storage Hydro
- 100 MW Pumped Storage Hydro and 100 MW Utility-scale PV

100 MW Pumped Storage Hydro

This sensitivity analysis added a 100 MW pumped storage hydro. The pumped storage hydro deferred the installation of a combustion turbine in the year it was placed in service. The 100 MW pumped storage hydro increased the overall system costs compared to the Base Plan and did not increase the RPS so this assumption was not included in the Preferred Plan.

100 MW Pumped Storage Hydro and 100 MW Utility-scale PV

This sensitivity analysis coupled a 100 MW utility-scale PV with a 100 MW pumped storage hydro. The energy provided by the 100 MW utility-scale PV was used to charge the pumped storage hydro during the day and was discharged at night during the evening peak. The pumped storage hydro again deferred the need for one combustion turbine. The 100 MW pumped storage hydro and 100 MW utility-scale PV increased the overall system costs compared to the Base Plan and increased RPS. This assumption was not included in the Preferred Plan.

Future Firm Generation Mix

The Base Plan assumed that future capacity needed to meet the capacity planning criteria would be provided by 100 MW combustion turbines. This sensitivity analysis assumed a mix of combustion turbines, combined cycle combustion turbines, and internal combustion engines that provided a more diverse set of operating characteristics for the future generation fleet. This future firm generation mix decreased the overall system costs compared to the Base Plan and was included in the Preferred Plan.

PREFERRED PLAN

The results of the sensitivity analyses that show positive impacts to the Base Plan were considered for incorporation into revising the Base Plan. Revisions to the Base Plan include a combination of results from the sensitivity analyses to produce the Preferred Plan which must be tested to assure system security reliability.

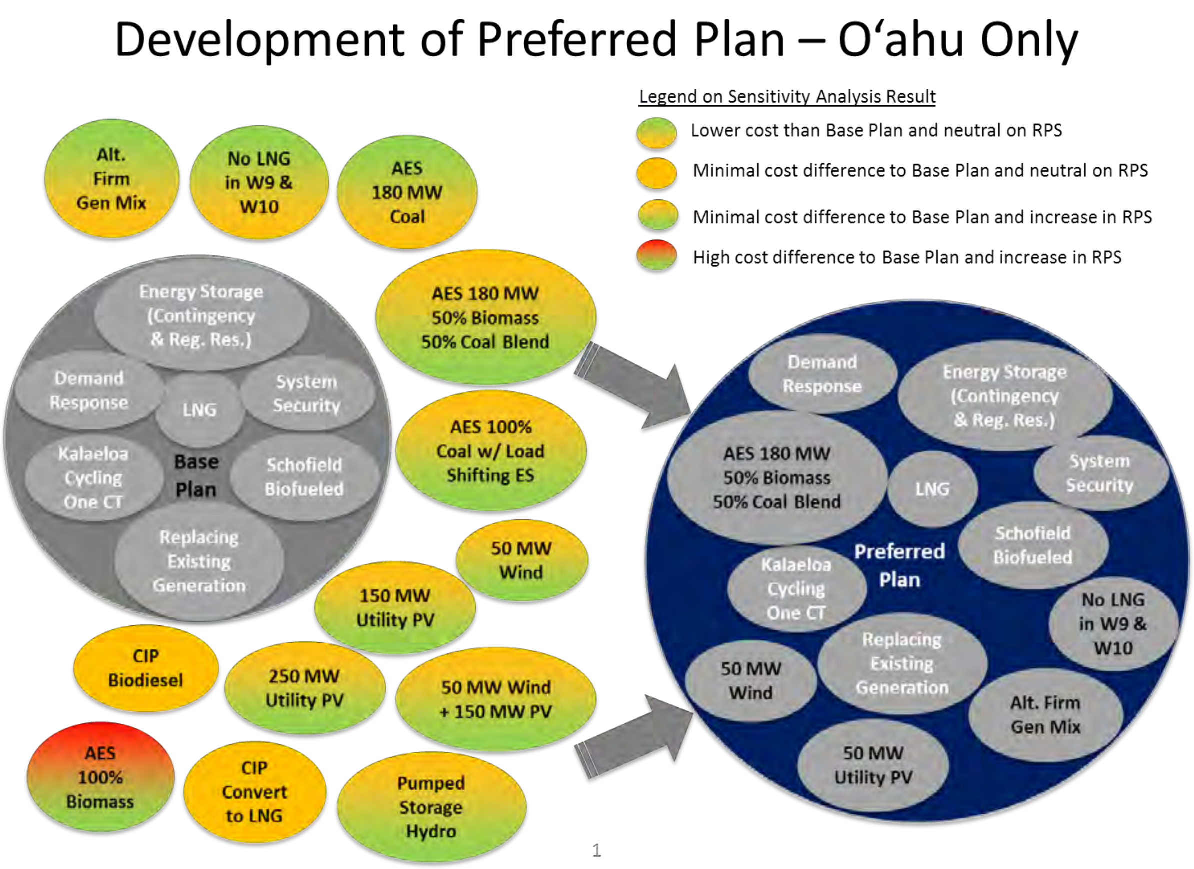


Figure L-2. Illustration of the Process for Developing the Hawaiian Electric Preferred Plan

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M: Planning Standards

This appendix contains the details of the planning standards TPL-001 and BAL-052.

TPL-001-0: TRANSMISSION PLANNING PERFORMANCE REQUIREMENTS

The starting document for HI-TPL-001-0 was NERC standard TPL-001-2 dated August 4, 2011. The standard includes the merging of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single comprehensive, coordinated standard and retirement of TPL-005-0 and TPL-006-0.

The only added complexity was that the differently sized power systems in Hawaiʻi would need different levels of system reliability. The Hawaiʻi standard has three groups to address the different sizes of the various Balancing Areas.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Working Group Glossary of Terms, Version 1 – 20120304 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-generation balance within a Balancing Authority Area, and governs the real time operation and control of the Balancing Area. (Source: Modified from Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012)

Base Year: The 2011 BA's transmission and generation system shall be used as the base year to establish performance standards utilized with this standard. (Source: Proposed RSWG proposed definition.)

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Corrective Action Plan: A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Equipment Rating: The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (for example, a line, a generator, a shunt compensator, transformer, etc.). (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive load, or (3) load that is disconnected from the system by end-user equipment. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Operating Procedure: A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Planning Assessment: Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection System: Protection system are:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

(Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Protection Reserves: The resources under the control of the Under Frequency Load Shedding System designed to protect the system against single or multiple contingency events. (Source: RSWG proposed definition.)

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAr), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

System: A combination of generation, transmission, and distribution components. (Source: Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012.)

Year One: Year One is the first year of planning studies for future planning and evaluation requirements. (Source: Modified Glossary of Terms Used in NERC Reliability Standards February 8, 2012, Reliability First Regional Definitions.)

Introduction

Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a system that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies.

Applicability: Balancing Authorities (BA)

Facilities: The Facilities are divided into three groups A, B, and C. All groups are divided based on the annual system peak demand.

- Group A: Annual system peak is greater than or equal to 500 MW.
- Group B: Annual system peak is greater than or equal to 50 MW and less than 500 MW.
- Group C: Annual system peak is less than 50 MW.

Effective Date: To be determined

B. Requirements

R1. The BA must maintain system models for performing the studies needed to complete its Planning Assessment. The models must use data consistent with that provided in accordance with the HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and must represent projected system conditions. This establishes Category P0 as the normal system condition in Table 1.

R1.1. System models must represent:

R1.1.1. Actual steady-state characteristics of system resources and loads as defined in HI-MOD-010 Development and Reporting of Steady State System Models and Simulations.

R1.1.2. Actual dynamic characteristics of system resources and loads as defined in HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations.

R1.1.3. Planned Facilities and changes to existing Facilities

R1.2. The Generation resources must maintain or better the following characteristics unless the change can be verified by study that the results will provide acceptable reliability. The characteristics of the system that meet the acceptable reliability criteria will be used as the new benchmark for future planning until the reliability criteria is changed.

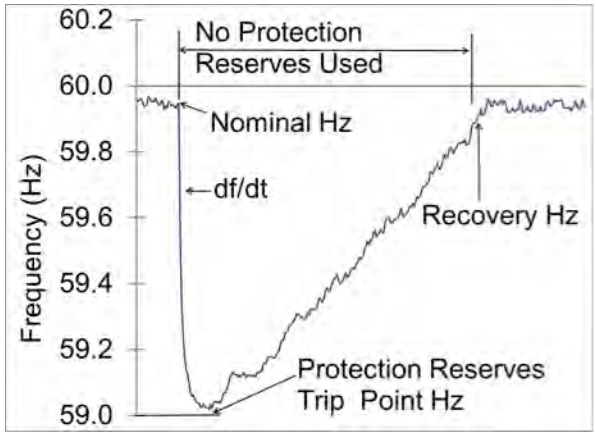
R1.2.1. Each Balance Authority system will be planned to meet the requirements Disturbance Recovery performance in HI-BAL-002 Disturbance Control Performance.

R1.2.2. The loss of the largest single contingency may result in a loss of load within the acceptable reliability criteria defined in BAL-002 Disturbance Control Performance.

R1.2.3. Each resource will have frequency ride-through designed such that all generation, reserves, regulation and voltage control resources will withstand single and excess contingency events defined in HI-BAL-002 Disturbance Control Performance. The ride-through capability will meet the criteria designed to be protected under HI-PRC-006 Underfrequency Load Shedding, without the loss of, or damage to any resource.

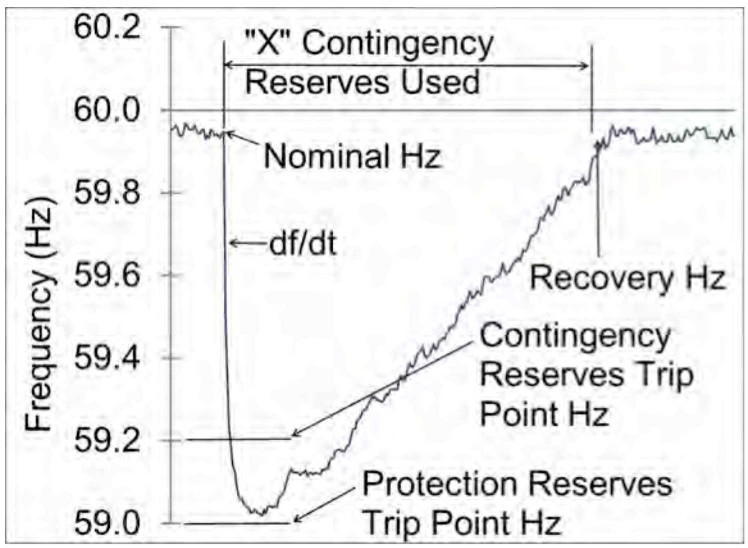
R1.2.4. The system will be planned such that the resultant impacts of inertia, unit response or reserve response will meet the system frequency response characteristics following the loss of the largest single contingency as defined below.

Frequency Response: For all BA systems the loss of the largest unit(s) or any single contingency should not result in activation of the protection reserves. In addition, the rate of change of frequency df/dt is not to increase over historical levels, without prior review of impacts on system protection operation and critical resources. A sample system performance characteristic is shown in the graph below:



System Using No Protection Reserves

An example characteristic graph of a system that utilizing the protection reserves is indicated below:



System Using Protection Reserves

R.1.2.5. The system will be planned such that all generation, reserves, regulation and voltage control resources will withstand the most severe voltage ride-thru requirement for a single contingency event, including both transmission and distribution events and distribution and transmission fault reclose cycles, through the duration of their reclosing cycle, without the loss of or damage to any resource.

R1.2.6. The system will be designed such that all generation, reserves, regulation and voltage control resources will withstand excess contingency events defined in HI-BAL-002 Disturbance Control Performance for voltage ride-thru requirement for an excess contingency event and designed to be protected under HI-PRC-006

Underfrequency Load Shedding, without the loss of or damage to any resource.

R1.2.7. The system will be planned to be transiently and dynamically stable following any single contingency event or any excess contingency event designed to be protected under HI-PRC-006 Underfrequency Load Shedding. Stability will be defined that the system will survive the first swing stability and the second swing and each subsequent swing will be lesser in magnitude than its predecessor (damped response). All swings will be effectively eliminated within 20 seconds of the initiating event.

R1.2.8. The system shall be designed to supply the required ancillary services necessary to provide voltage and frequency response to meet the reliability requirements of each BA's service tariff and R1.2.2.

R2. The BA must prepare an annual Planning Assessment of its system. This Planning Assessment must use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by current annual studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak load for either year one or year two, and for year five.

R2.1.2. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.1.3. System minimum day load, maximum variable renewable for one of the five years.

R2.1.4. System day-peak load with maximum variable renewable and minimum variable renewable for one of the five years.

R2.1.5. System peak load, no variable renewable for one of the five years.

R2.1.6. For each of the studies described in R2.1.1 through R2.1.5, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response:

- Real and reactive forecasted load.
- Expected transfers.
- Expected in-service dates of new or modified Transmission Facilities.
- Planned or unplanned outages of critical resources for ancillary services
- Typical generation scenarios including outage of the typically operated generation sources
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable loads and Demand Side Management.

R2.1.7. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on system performance must be studied. The studies must be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis must be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in R2.6:

R2.2.1. A current study assessing expected system peak load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.3. The short circuit analysis portion of the Planning Assessment must be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6. The analysis must be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis must be assessed annually and be supported by current or past studies as qualified in R2.6. The following studies are required:

R2.4.1. System peak load for one of the five years. System peak load levels must include a load model which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads or other load characteristics, including the model of distributed generation, Demand Response and other programs that impact system load characteristics. An aggregate system load model which represents the overall dynamic behavior of the load is acceptable.

R2.4.2. System minimum load for one of the five years.

R2.4.3. System minimum with maximum and minimum variable renewables (night-time load) load for one of the five years.

R2.4.4. System minimum day load, maximum variable renewable for one of the five years.

R2.4.5. System day-peak load, maximum and minimum variable renewable for one of the five years.

R2.4.6. System peak load, no variable renewable for one of the five years.

R2.4.7. For each of the studies described in R2.4.1 through R2.4.6, sensitivity case(s) must be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, load forecast, or dynamic load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability
- Maintenance periods of generation resources and alternative resources providing ancillary services.
- Generation additions, retirements, or other dispatch scenarios.

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis must be assessed to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and must include documentation to support the technical rationale for determining material changes.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or Stability analysis: the study must be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the system represented in the study. Documentation to support the technical rationale for determining material changes must be included.

R2.7. For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the Planning Assessment must include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system must continue to meet the performance requirements in Table 1. The Corrective Action Plan(s) must:

R2.7.1. List system deficiencies and the associated actions needed to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback or tripping as a response to a single or multiple Contingency to mitigate steady state performance violations

- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, DSM, alternative resources and technologies, or other initiatives

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the BA that prevent the implementation of a Corrective Action Plan in the required time frame, then the BA is permitted to utilize Non-Consequential Load Loss to correct the situation that would normally not be permitted in Table 1, provided that the BA documents that they are taking actions to resolve the situation. The BA must document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified system Facilities and Operating Procedures.

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment must include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan must:

R2.8.1. List system deficiencies and the associated actions needed to achieve required system performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, the BA must perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1, and R2.2. The studies must be based on computer simulation models using data provided in R1.

R3.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R3.4.

R3.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R3.3. Contingency analyses for R3.1 & R3.2 must:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- Tripping of Transmission elements where relay loadability limits are exceeded.
- Tripping of generation and other resources (including distributed resources) where ride-thru capabilities are exceeded

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4. Those planning events in Table 1, that are expected to produce more severe system impacts must be identified and a list of those Contingencies to be evaluated for system performance in R3.1 created. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R3.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) must be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, the BA must perform the Contingency analyses listed in

Table 1. The studies must be based on computer simulation models using data provided in Requirement R1.

R4.1. Studies must be performed for planning events to determine whether the system meets the performance requirements in Table 1 based on the Contingency list created in R4.4.

R4.1.1. For planning event P1: No generating unit must pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

R4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings must not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

R4.1.3. For planning events P1 through P7: Power oscillations must exhibit acceptable damping as established by the BA.

R4.2. Studies must be performed to assess the impact of the extreme events which are identified by the list created in R4.5.

R4.3. Contingency analyses for R4.1 and R4.2 must:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses must include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- Tripping of all generation sources whose ride-thru capabilities are exceeded.

R4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static VAR compensators and power flow controllers.

R4.4. Those planning events in Table 1 that are expected to produce more severe system impacts on its portion of the system, must be identified, and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation must be available as supporting information.

R4.5. Those extreme events in Table 1 that are expected to produce more severe system impacts must be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation must be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted.

R5. The BA must have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system. For transient voltage response, the criteria must at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

R6. The BA must define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

R7. The BA must distribute its Planning Assessment results to the Hawaiʻi PUC (or designee) within 30 calendar days upon a written request for the information.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

1. The system must remain stable. Cascading and uncontrolled islanding must not occur.
2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
4. Simulate Normal Clearing unless otherwise specified.
5. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings
6. Phase angle separation for line contingency must not preclude automatic reclosing for BA groups B and C, unless system Adjustments can be performed within fifteen minutes.

Steady State Only:

7. Applicable Facility Ratings must not be exceeded.
8. System steady state voltages and post-Contingency voltage deviations must be within acceptable limits as established by the BA.
9. Planning event P0 is applicable to steady state only.
10. The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event must not be used to meet steady state performance requirements.

Stability Only:

11. Transient voltage response must be within acceptable limits established by the BA.

Category	Initial Condition	Event[1]	Fault Type[2]	Non-Consequential Load Loss Allowed	Range of Customers Loss Allowed	Applicable BA Groups[3]
P0 No Contingency	Normal system	None	N/A	No	None	A, B, and C
P1 Single Contingency	Normal system	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device-Ancillary Service Device[5] 5. Generator – no fault	3Ø and SLG for Events 1 through 4, N/A for Event	Yes	Up to 12% generation only	A
				Yes	Up to 15% generation only	B
				Yes	Up to 15% generation only	C

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups[3]**
P2 Single Contingency	Normal system	1. Opening a line section w/o fault[6]	N/A	No	None	A, B, and C
		2. Bus Section fault	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
		3. Internal Breaker Fault[7] (Transmission line breaker)	SLG	Yes	none	A
				Yes	none	B
				Yes	none	C
P3 Single Contingency	Loss of generator unit followed by System adjustments[8]	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device/ Ancillary Service Device[5]	3Ø and SLG	No	up to 12%	A
				Yes	up to 40%	B
				Yes	up to 40%	C

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups[3]**
P4 Multiple Contingency (Fault plus stuck breaker[10])	Normal system	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	Yes	Up to 65%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Up to 65%	A[13]
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]

Table 1 – Steady State & Stability Performance Planning Events—Continued						
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Non-Consequential Load Loss Allowed**	**Range of Customers Loss Allowed**	**Applicable BA Groups[3]**
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal system	Delayed Fault Clearing due to the failure of a non-redundant relay[12] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer[4] 4. Shunt Device[5] 5. Bus Section	SLG	No	None	A
				Yes	Up to 15%	B
				Yes	Up to 15%	C
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by system adjustments[8] 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	Loss of one of the following: 1. Transmission Circuits 2. Transformer[4] 3. Shunt Device[5]	3Ø	No	Up to 40%	A
				Yes	Up to 65%	B[13]
				Yes	Up to 65%	C[13]
P7 Multiple Contingency (Common Structure)	Normal system	The loss of any two adjacent (vertically or horizontally) circuits on common wood structure[10]	SLG	No	Up to 40%	A
				Yes	Up to 65%	B
				Yes	Up to 65%	C

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">
Steady State & Stability
For all extreme events evaluated:
1. Simulate the removal of all elements that Protection systems and automatic controls are expected to disconnect for each Contingency.
2. Simulate Normal Clearing unless otherwise specified.
</td></tr>
<tr><td>
Steady State
1. Loss of a single generator, Transmission Circuit, shunt device, or transformer force out of service followed by another single generator, Transmission Circuit, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the transmission system such as:
a. Loss of a tower line with three or more circuits[10].
b. Loss of all Transmission lines on a common Right-of-Way[10].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large load or major load center.
3. Wide area events affecting the Transmission System based on system topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large fuel line into an area.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires
iv. Severe weather, for example, hurricanes
v. A successful cyber attack
vi. Large earthquake, tsunami or volcanic eruption
b. Other events based upon operating experience that may result in wide area disturbances.
</td><td>
Stability
1. Loss of a single generator, Transmission circuit, shunt device, or transformer force out of service apply a 3Ø fault on another single generator, Transmission circuit, shunt device, or transformer prior to system adjustments.
2. Local area events affecting the transmission system such as:
a. 3Ø fault on generator with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[9] or a relay failure[12] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.
</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Event and Extreme Events)

Footnotes

1. If the event analyzed involves system elements at multiple system voltage levels, the lowest system voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. The Applicable BA Groups (A, B or C) is defined under Facilities and is determined by the annual system peak demand.
4. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the system connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
5. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
6. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving load radial from a single source point.
7. An internal breaker fault means a breaker failing internally, thus creating a system fault which must be cleared by protection on both sides of the breaker.
8. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Transmission following Contingency events. System adjustment (as identified in the column entitled 'Initial Condition') when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
9. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
10. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
11. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address System performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address system performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated.
12. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32 & 67), and tripping (#86 & 94).
13. Indicates that the system level for the Category is an extreme event for the Group.

C. Measures

M1. The BA must provide evidence, in electronic or hard copy format, that it is maintaining system models within their respective area, using data consistent with HI-MOD-010 Development and Reporting of Steady State System Models and Simulations and HI-MOD-012 Development and Reporting of Dynamic System Models and Simulations, including items represented in the Corrective Action Plan, representing projected system conditions, and that the models represent the required information in accordance with R1.

M2. The BA must provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the system in accordance with Requirement R2.

M3. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. The BA must provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. The BA must provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its system in accordance with Requirement R5.

M6. The BA must provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify system instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. The BA must provide evidence, such as email notices, postal receipts showing recipient and date that it has distributed its Planning Assessment results to the Hawai'i PUC (or designee) within 30 calendar days upon a written request for the information in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

Hawai'i PUC (or designee).

1.2. Data Retention:

The BA must each retain data or evidence to show compliance as identified unless directed by its Hawai'i PUC (or designee) to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable system steady state voltage limits, post-contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- Three calendar years of the notifications employed in accordance with Requirement R7 and Measure M7.

If the BA is found non-compliant, it must keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Processes:

- Compliance Audits: The Hawai'i PUC (or designee) will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA's system model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5. for Requirement R1 and Measurement M1.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to comply with Requirement R2, Part 2.6. for Requirement R2 and Measurement M2

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. Levels of Non-Compliance for Requirement R3, Measure M3:

4.1. Level 1: The BA did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5. for Requirement R3 and Measurement M3.

4.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. Levels of Non-Compliance for Requirement R4, Measure M4:

5.1. Level 1: The BA did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5 for Requirement R4 and Measurement M4.

5.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. Levels of Non-Compliance for Requirement R5, Measure M5:

   6.1. Level 1: N/A

   6.2. Level 2: The BA does not have criteria for acceptable system steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its system for Requirement R5 and Measurement M5.

7. Levels of Non-Compliance for Requirement R6, Measure M6:

   7.1. Level 1: N/A

   7.2. Level 2: The BA failed to define and document the criteria or methodology for system instability used within its analysis as described in Requirement R6 for Requirement R6 and Measurement M6.

8. Levels of Non-Compliance for Requirement R7, Measure M7:

   8.1. The BA distributed its Planning Assessment results to Hawaiʻi PUC (or designee) but it was more than 30 days but less than or equal to 40 days following the request as described in Requirement R7 for Requirement R7 and Measurement M7.

   8.2. The BA failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.

BAL-502-0: RESOURCE ADEQUACY ANALYSIS, ASSESSMENT, AND DOCUMENTATION

A. Introduction

Purpose: To establish common criteria for each Balancing Authority (BA) based on "one day in *x* year" (determined by study) loss of load expectation principles or as an alternative a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment and documentation of Resource Adequacy, will include Planning Reserve Margins for meeting system load for the BA's system. The analysis will also include resource adequacy analysis for frequency response, spinning reserve, off-line reserves and other resource characteristics required to meet the reliability criteria.

Applicability: Balancing Authorities (BA) are divided into two groups based on the annual system Peak Demand.

- Group A: Annual system peak is greater than 50 MW.
- Group B: Annual system peak is less than or equal to 50 MW.

Effective Date: To be determined

B. Requirements

R1. The Group A utilities will establish at their discretion whether to use Resource Adequacy analysis using requirements defined in either R1.1 or R1.2 for each planning year. Group B will use the planning methodology defined in R1.2 for each planning year.

R1.1. Group A: "one day in *x* year criteria". The utility will establish the methodology and procedures used to establish the "one day in *x* year" criteria to meet the system peak load to be served by the BA. The methodology should evaluate the reliability of the generating resources, the capacity and system requirements of the BA and the alternatives to resource commitment available to meet the desired reliability criteria for each of the BA's utility loss of load expectations methodologies. In addition the methodology should include the consideration of, renewable capacity from as-available renewable resources using the reliability based methods described in R1.2 for L_{QC}. Consideration will also be given to ensure that the enough generating resources are installed on system that have the capability to provide the operating ancillary services such as frequency response, spinning reserve, voltage regulation, frequency regulation and other services during the same time periods included in HI-TPL-001 Transmission Planning Performance Requirements as follows:

R1.1.1. Minimum day load with no as-available renewable generation

R1.1.2. Minimum day load with as-available maximum renewable generation

R1.1.3. Maximum load with no as-available renewable generation

R1.1.4. Maximum load with maximum as-available renewable generation.

R1.2. Group A and Group B: "reserve margin of *xx*% criteria". The utility will maintain a minimum *xx*% Reserve Margin (F_{RM}) over the annual system peak.

$$\frac{\sum_{i=1}^{N} N_i + L_{DR} + L_{QC} - L_{Peak}}{L_{Peak} - L_{DR}} \geq F_{RM}$$

Where:

- F_{RM} is the Reserve Margin.
- N_i is the Normal Net Capability of all firm units.

- L_{DR} is the amount of Interruptible Demand and Direct Control Load Management (DCLM) exclusively available and measureable for the BA’s interruption for the entire period of the expected capacity shortfall. Such Interruptible Demand and DCLM will not infringe on the protective reserve for system security required by HI-BAL-006 Underfrequency Load Shedding.
- L_{QC} is the estimated capacity value of grid-side as-available renewable and stored energy generation on the system. The estimated capacity value of grid-side as-available generation and stored energy will be determined by the utility using reliability or statistical based calculation methods depending upon the available data. Reliability based methods that may be used include the effective load carrying capability (ELCC), equivalent conventional power (ECP), or equivalent firm capacity (EFC) methods. Statistical based methods may consist of the relevant time period of the system peak and renewable energy over a time series of data. For example, the estimated capacity L_{QC} is the level where over that system peak period in which 90% of the data points are available to serve the system peak. For existing installations, the capacity value will be calculated using three years of actual data for each group of similar as-available renewables such as wind, hydro, PV, etc. For future installations the estimated capacity value will be based on estimated capacity value calculations for similarly located resources installed in Hawaiʻi. For future as-available resources where no Hawaiʻi historical data is available, the best available data shall be used for calculations. For the first year of data, the estimated capacity value shall be adjusted by 0.7 followed by 0.8 after gathering the second year of data. Following the third year of data, the actual data shall be used to determine the capacity value.
- L_{Peak} is the forecasted annual system peak load.

The Reserve Margin analysis will also consider as a secondary planning criteria that the BA’s total Normal Net Capability of all firm units of the system less the capacity of the unit(s) scheduled for maintenance less the capacity that would be lost by the Forced Outage of the largest single contingency plus the total amount of interruptible loads plus the estimated capacity value of grid-side as-available renewable and stored energy generation on the system, if appropriate, and dedicated for serving the entire period of the peak ,must be equal to or greater than the forecasted system peak load.

$$\sum_{i=1}^{N} N_i - \sum_{m=1}^{N} N_m - N_{FO} + L_{DR} + L_{QC} \geq L_{Peak}$$

Where:

- N_m is the Normal Net Capability of units on scheduled maintenance.
- N_{FO} is the Normal Net Capability of the largest single contingency lost by Forced Outage.

R1.3. The BA for each Group A system will stipulate the use of either R1.1. or R1.2. for planning. The Resource Adequacy analysis must calculate a Planning Reserve Margin for the applicable group that will either result from the sum of the probabilities for Loss of Load for the system Peak Demand for all days of each planning year analyzed (per R1.1) being equal to *xx*. (This is comparable to a "one day in *x* year" criterion) or document that the applicable Balance Authority has developed a resource plan that encompasses a *xx*% Reserve Margin for Group A (per R1.2). Group B will use the Reserve Margin criteria (per R.1.2). The reserve margin target will be utilized until such a time that a new study determines a change in the reserve margin is warranted.

R1.4. The BA will develop criteria to ensure the generation characteristics address the following system requirements:

R1.4.1. Starting and loading time if resources are to be used as Contingency Reserves as required in HI-BAL-002 Disturbance Control Standard.

R1.4.2. The Frequency and Inertia response characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.3. The Voltage and Frequency ride-through characteristics as required in HI-BAL-001 Transmission System Planning Performance Requirements.

R1.4.4. Short circuit current requirements.

R1.4.5. Dispatch characteristics (starting time, ramp rate, minimum values, regulation, etc.) as required to meet the requirements of the planning period.

R1.4.6. Any other ancillary resources required to meet system security requirements which have been identified as necessary through analysis of the planning period.

R1.5. Be performed or verified separately for each of the following planning years:

R1.5.1. Perform an analysis for Year One.

R1.5.2. Perform an analysis or verification when changes in measured non-dispatchable generation or net load changes more than *x* MW/year or *x* MW (amount established by each BA) from Year One or there are planned or unplanned changes in resource development other than nondispatchable generation or DG.

R1.6. Include the following subject matter and documentation of its use:

R1.6.1. Criteria for including planned resource additions in the analysis.

R1.6.2. Load forecast characteristics:

- Median forecast peak load.
- Load forecast uncertainty (reflects variability in the load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable or Interruptible Demand.
- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Historic resource performance and any projected changes.

Seasonal resource ratings.

- Resource planned outage schedules, deratings, and retirements.
- Intermittent and energy limited resources such as wind, PV, and cogeneration may be considered holistically using time synchronized data with load. The relevant time period of the system peak must be defined using a minimum of three years of data.

R1.6.3. Transmission limitations that prevent the delivery of generation reserves.

R1.6.3.1. Criteria for including planned Transmission Facility additions in the analysis.

R1.6.3.2. Criteria for remedial action systems employed in lieu of Transmission improvements.

R1.7. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Common mode outages that affect resource availability.
- Environmental or regulatory restrictions of resource availability.
- Any other demand (load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather or drought conditions that affect unit availability.

R1.8. Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.

R2. The BA must annually document the projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.

R2.1. This documentation must cover each of the years in Year One through ten.

R2.2. This documentation must include the Planning Reserve Margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3. The documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 days after the close of the year.

C. Measures

M1. The BA must possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1.

M2. The BA must possess the documentation of its projected load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1. Hawai'i PUC (or designee)

1.2. Compliance Monitoring Period and Reset Timeframe

1.2.1. One calendar year

1.3. Data Retention

1.3.1. The BA must retain information from the most current and prior two years. The Hawai'i PUC (or designee) will retain any audit data for five years.

2. Levels of Non-Compliance for Requirement R1, Measure M1:

2.1. Level 1: The BA met one of the following conditions for Requirement R1 and Measurement M1.

2.1.1. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included.

2.1.2. The BA Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.6.

2.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2:

3.1. Level 1: The BA failed to publicly post the documents as specified per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3 for Requirement R2 and Measurement M2.

3.2. Level 2: The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2. The PUC or its designee will give notice to the BA within 30 days of years' end for a compliance audit and will complete such audit within 90 days of such information being supplied by the BA.

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N. System Operation and Transparency of Operations

PRUDENT DISPATCH AND OPERATIONAL PRACTICES

The Companies' unit commitment and economic dispatch policies are based on safe and reliable operation of the system, minimizing operating costs, and complying with contractual and regulatory obligations. The daily generation dispatch process is illustrated in Figure N-1.

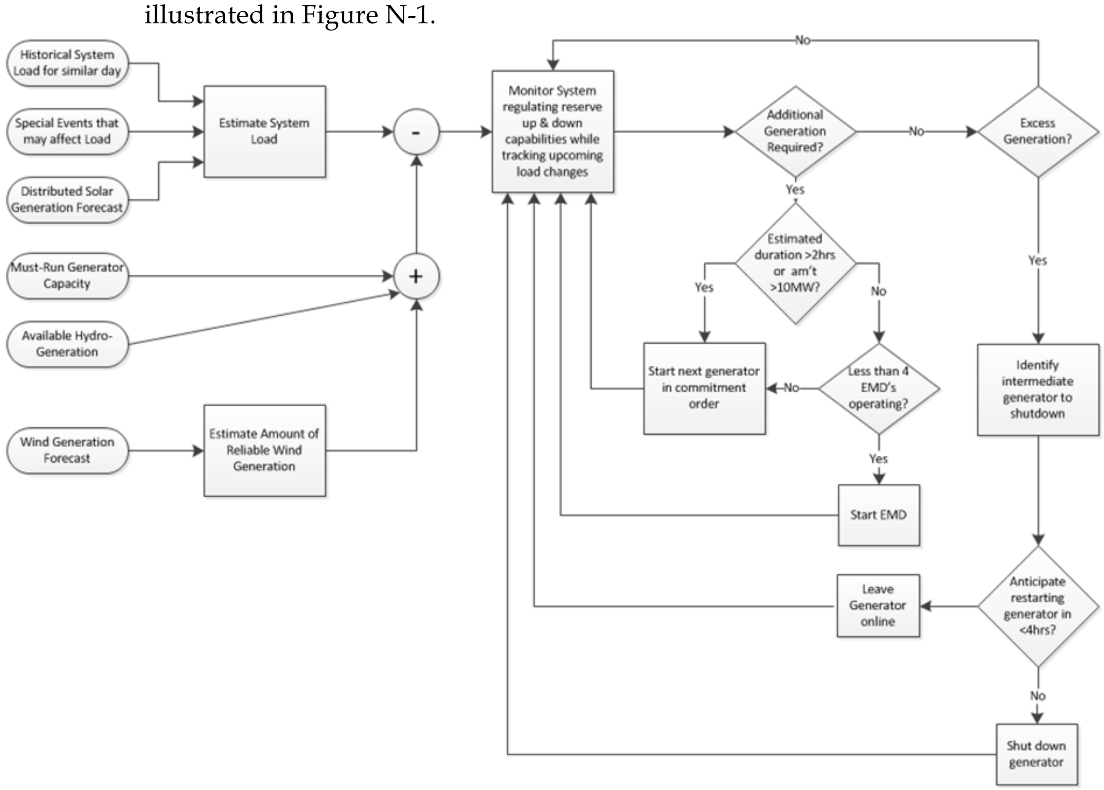

Figure N-1. Daily Generation Dispatch Process

In the future, the goal is for the System Operator to be able to incorporate a more automated approach to unit commitment and dispatch with increased amounts of variable renewable generation (wind and solar), quick-starting engines, energy storage, and demand response resources on the grid. The Energy Manage Systems (EMS) would likely be interfaced/integrated with corresponding Demand Response Management Systems (DRMS) and Energy Storage Management Systems (ESMS). This would also include integrating the demand forecast, with wind and solar forecasts to achieve a net demand to be used for unit commitment.

Minimization of Ancillary Services Costs

The process to identify system security constraints, and the combinations of resources which can be used to meet them, is summarized as follows:

- Determine system constraints.
- Identify the resource mix that meets each of them.
- Select the lowest cost combination of resources to operate.

For all three operating companies, additional security constraints are imposed with increased concentrations of variable renewable resources. Therefore, the projected increase in distributed PV may have an impact on ancillary service costs. The Companies will continually evaluate the economics of using existing resources to meet ancillary service and system security requirements versus meeting those needs with alternative resources including energy storage and demand response.

Maximizing the Use of Available Renewable Energy

The commitment and dispatch of renewable energy resources depends upon the contract terms for those resources and whether or not the system operator has visibility and control over the generation. If the resource can be economically dispatched, it is put under automatic generation control (AGC), and its output is determined by its marginal cost relative to the marginal cost of other resources. Examples of this type of renewable resource includes geothermal, generating units using renewable biofuels, waste-to-energy projects, and other "firm" renewable projects.

To date, variable renewable energy projects are contractually treated as "must-take," variable energy. These resources are accepted regardless of cost, but their output is reduced as needed when all intermediate units are off line and there remains excess energy production. In this case the system operator limits, or "curtails" the output of variable energy providers to the degree necessary to keep the system in balance and provide response reserves. Most curtailments are partial—the output is limited but the resource is not restricted to zero output. When curtailment is necessary due to excess energy, it is performed in a manner consistent with the purchased power agreements associated with the affected resources and in accordance with a priority order established by the system operator.

In addition to excess energy situations, curtailments can also be required for system constraints such as line loading, phase angle separation, line maintenance, and frequency impact from power fluctuations. Curtailments for system constraints are applied to the resources as needed to address these constraints and are not subject to the priority order used for excess energy curtailments. Curtailments are also performed at the request of wind plants for wind conditions, and equipment issues. The number of curtailment events, the reason, and their duration are reported monthly through various reports to the Commission such as the monthly report filed by the Hawaiian Electric Companies in Docket No. 2011-0206 (RSWG).

The vast majority of distributed solar PV is not visible or controllable by the system operator. These resources serve demand ahead of all other resources. Additional growth in distributed solar PV these resources is forecast to cause increased curtailments of utility-scale variable renewable resources, unless distributed solar PV is required to provide the visibility and control to the system operator.

Energy Management Systems (EMS)

The operation of the system is facilitated by use of a centralized Energy Management System (EMS). The EMS provides the system operator with constantly updated, real-time information about the operational state of the system. There are three key program applications within the EMS:

- Supervisory Control and Data Acquisition (SCADA)
- Real-time Automatic Generation Control (AGC)
- Real-time State Estimator

The Companies routinely update the EMS hardware and software platforms for each system in order to ensure reliable operation, to incorporate new industry developments such as protocols and system security measures, and to maintain support from EMS vendors[1]. The most recent migration to a new platform was completed in late 2013.

[1] The Companies operate EMS systems from two different vendors, *Alstom* at Hawai'i Electric Light and Maui Electric, and *Siemens* at Hawaiian Electric.

System Dispatch and Unit Commitment

Unit commitment and dispatch decisions are based upon:

Safety. The Companies' dispatch of generating resources is always subject to ensuring the safety of Company personnel and the general public.

Reliability. Dispatch and unit commitment must adhere to system security and generation adequacy requirements.

Contractual Requirements. Dispatch and unit commitment must adhere to contractual constraints.

Cost. After meeting all the forgoing requirements, the Company commits units and dispatches units based on their marginal cost, with lower cost units being committed and operated before higher cost units.

When determining the unit commitment and dispatch of generating units, the Company does not differentiate between dispatchable IPPs and utility-owned assets. The daily unit commitment modeling tool input date does not differentiate units by ownership. Certain generators do receive a form of priority in terms of energy being accepted onto the system on the basis of the location of the generator, its characteristics, or the contractual obligations unique to the resource. The acceptance of energy is in the following order of preference:

- **Distributed generation:** Distributed generation resources receive preferential treatment as "must take" resources regardless of their economic merit for system dispatch. This includes Standard Interconnection Agreement (SIA) distributed generation and Net Energy Metering (NEM) distributed generation. At the present time, the Companies have no control over, or ability to curtail, distributed generation.
- **Scheduled contractually obligated generation:** These resources are preferentially treated from a dispatch perspective by contract. They are used to serve customer load regardless of their economic merit for system dispatch. Scheduled energy from these resources is taken after distributed generation, but ahead of all other resources including variable energy providers.
- **Contractually must-run, dispatchable generation:** The resources cannot be cycled offline and therefore the minimum dispatch level of these resources are preferentially treated in the system dispatch determination and the energy is accepted from these resources regardless of cost, except during periods of maintenance.
- **Generation to meet system security constraints:** These resources provide energy at least at their minimum dispatch limit, ahead of other resources, similar to contractual must-run and scheduled generation, plus an amount of reserve capability to provide down regulation. However, once dispatched, the continued operating status of these

resources is subject to continual evaluation of their costs relative to other alternative resources that may become available at a lower cost, except where it is required by contract.

- **Variable energy:** As available energy is accepted on the system, regardless of cost, after distributed generation, scheduled energy purchases, and continuously operated generation. This energy is accepted regardless of cost and thus presents a constraint on optimized (lowest) cost. If the energy cannot be accommodated due to low demand, curtailment of the resource is ordered according to an established and approved priority order.
- **Dispatchable resources:** Energy from dispatchable resources is taken on the basis of relative cost (economic dispatch). Resources with the lowest variable energy (fuel and O&M) cost will be committed ahead of resources with higher variable costs. Online resources with lower incremental costs will be dispatched at higher outputs ahead of resources with higher incremental costs. The units operated routinely to meet demand, but cycled offline during minimum demand periods, are described as intermediate units. Short-term (daily) unit commitment decisions do not consider fixed costs associated with these resources because the fixed costs will be incurred regardless of whether or not the unit is operated.

Utilization of Energy Storage and Demand Response

Energy storage and demand response programs can provide the system operator with a flexible resource capable of providing capacity and ancillary services. In order to provide the system operator with appropriate control and visibility of energy storage assets will be equipped with essentially the same telemetry and controls necessary to operate generating units. Demand response used for providing regulation reserves and contingency reserves will also be equipped with appropriate telemetry and controls. The specific interface requirements depend upon whether the storage device or demand response resource is responding automatically, or is under the control of the system operator. DRMS and/or ESMS may be interfaced with or directly incorporated in an EMS. For storage or demand response that is integrated into the EMS, telemetry requirements include:

- For storage, real-time telemetry indicating charging state, amount of energy being produced, device status.
- Control interface to the EMS to enable the increase and decrease of energy output from the storage asset, and for energy input to the storage device for charging.
- For demand response, real-time telemetry indicating breaker status, switch status, and load.

- Control interface to the EMS to enable the triggering of load shed in response to automatic signals (for example, underfrequency) or a command from the system operator.

Depending on the specific application, storage may also be required to respond to local signals. For example, storage may need the capability to respond to a system frequency change in a manner similar to generator governor droop response, which may be used for a contingency reserve response or for frequency responsive regulating reserve. Another example of local response includes the ability of the storage to change output (or absorb energy) in response to another input signal from a variable renewable energy resource in order to provide "smoothing" of the renewable resource output.

A special consideration of short-duration storage is the fact that it is a limited energy resource. This introduces the need for the system operator to be informed regarding the storage asset's charging state, and the need to ensure that the integration and operation of these resources allows for replacement energy sources prior to depletion of the storage. This replacement could be in the form of longer-term storage or generation resources. In order for the value of the demand response to be realized in providing a particular grid service, once called, the load cannot return to the system until after a specified time, which is dependent on the type of grid service being provided by the demand response resource. Accordingly, the system operator similarly requires information regarding the status of demand response, particularly as it relates to the state of the response after an event has been triggered.

Visibility and Transparency in System Dispatch

A high level review of the Renewable Watch websites of various ISOs including PJM, MISO, Cal ISO, and ERCOT shows the following operational information commonly being displayed, along with ISO energy market-specific information such as locational marginal pricing:

- Real time daily demand curve showing actual and forecasted demand, updated at least hourly
- Hourly wind power MW or MWh being produced and forecasted
- Other renewable energy production in MW (California)
- Available generation resources

The Company's Renewable Watch site currently displays the following information, with data updated approximately every 30 minutes:

Net Energy System Load. The system load served by generators on the "utility-side" of the meter including those owned by the utility and by independent power producers (IPP).

Gross System Load. The net system load plus estimated load served by "customer-side" of the meter by DG-PV.

Solar Irradiance Data. This data is measured in different regions of the island, which are used as input to calculating the estimated load served by customer-side PV.

Wind Power Production. Total megawatts of wind power being produced by the various IPP-owned wind farms selling electricity to Hawaiian Electric.

To provide further information to customers about the dispatch of various energy generation resources under the utility's control, the Company is currently partnering with the Blue Planet Foundation to develop and publicly present real time breakouts of the percentage of net energy system load being served by various fuel types, including coal, oil, wind, waste-to-energy, solar, and biofuel. Hawaiian Electric and Blue Planet believe this information will be useful in raising customer awareness of the use of renewable energy versus fossil fuels. A prototype kiosk was displayed at the Hawaiʻi Clean Energy Day event on July 22, 2014 with positive public reaction.

In light of this information already being developed for public display, Hawaiian Electric is agreeable to the following enhancements to its website:

- The information on the Renewable Energy watch website will be supplemented with additional information showing for the previous hour the percentage of the energy supplied by the different resources (IPPs, Renewables, Company generating units).
- A historical archive of the percentage of the energy produced by each of the resource groups for the previous 24 hour period will be maintained so that the customer can view the changes over time.

These enhancements will address the Commission's objectives of showing the significant use of non-utility generation and renewable resources, most of which, with the exception of Hawaiian Electric's biofueled combustion turbine generation CT-1, are IPP owned.

In addition to the above, Hawaiian Electric will also make public a description of its economic dispatch policies and procedures, via posting on its company website. Combined, the enhancements to the Hawaiian Electric website and the sharing of its dispatch policies and procedures will increase visibility and transparency of how generating resources are being dispatched on the Hawaiian Electric system.

As previously mentioned the Companies generating unit commitment and dispatch of the generating units is based on the objective of incurring the least cost to the customers while continuing to maintain system reliability. With the introduction of increasing amounts of renewable resources on the systems, it has become more important to minimize the use of fossil fuels and contending with the dynamic system changes that occur from the new resources so that reliability can be maintained. A screenshot from the Renewable Watch–O'ahu website is shown below in Figure N-2 to provide an example of the variability of the renewable energy resources.

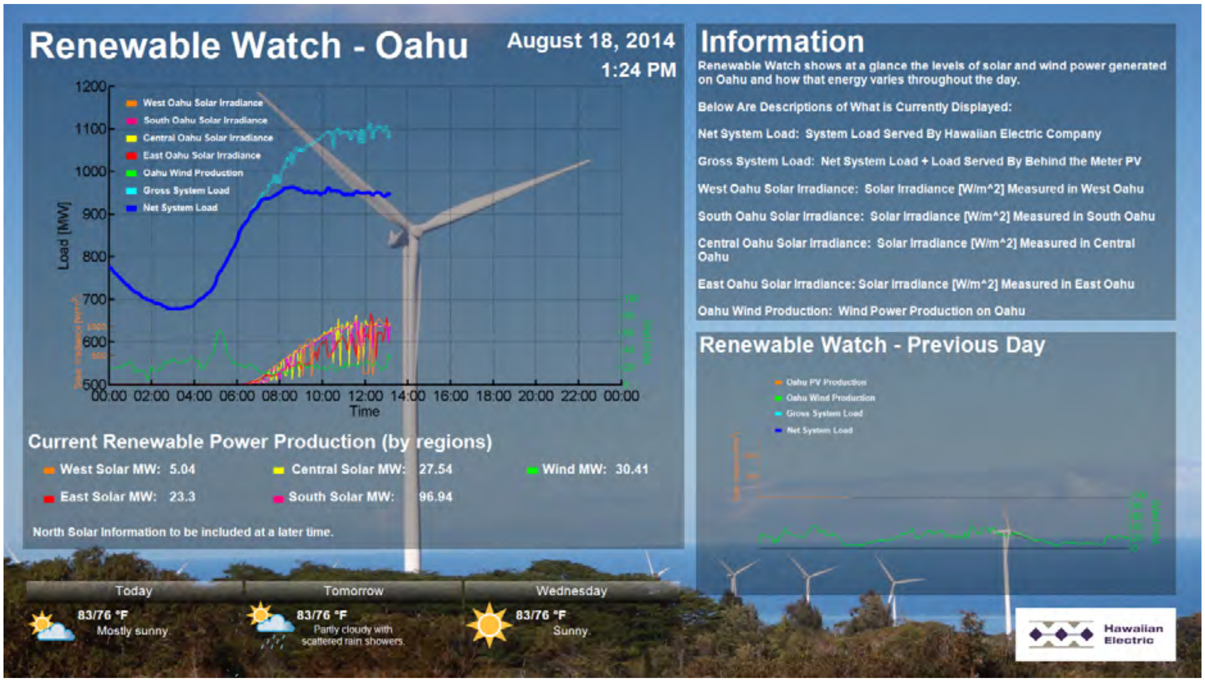

Figure N-2. Renewable Watch–O'ahu Website Screenshot of Information Displayed for August 18, 2014.

Keep in mind that the changes that have been occurring on the Companies' respective systems have been occurring for a few years but at different rates of change. The neighbor island systems (Maui and Hawai'i Island) have been changing at a far more rapid pace due to the high availability of renewable resources that could be used on each island.

CAPACITY VALUE OF VARIABLE GENERATION AND DEMAND RESPONSE

Accurately assessing the capacity value of variable generation and demand response resources are critical components toward meeting customer demand and maintaining system reliability. Because wind and solar are variable resources, determining its capacity value becomes a considerable challenge in order to achieve the confidence required to include variable generation resources to replace firm generation.

Capacity Value of Wind Generation

Hawaiian Electric

The contribution of existing and future wind resources to capacity planning is reflected in the Loss of Load Probability (LOLP) analysis. In the modeling determination of when additional firm capacity may be needed based on the application of Hawaiian Electric's generating system reliability guideline (4.5 years per day), the wind resources' contribution to serving load will be reflected in the LOLP calculations. As such, wind resources' contribution to capacity planning is dependent upon the composition and assumptions in each plan.

Hawai'i Electric Light

The aggregate value of the two existing wind farms (20.5 MW Tawhiri wind generating facility and 10.56 MW Hawi Renewable Development wind farm) contribution to capacity planning is 3.1 MW.

The capacity value of future wind farms in the PSIP is 10% of the nameplate value of the facility to be added.

Maui Electric

The aggregate value of the three existing wind farms (20 MW Kaheawa Wind Power I, 21 MW Kaheawa Wind Power II, 21 MW Auwahi Wind Energy) contribution to capacity planning is 2 MW.

The capacity value of future wind farms in the PSIP is 3% of the nameplate value of the facility to be added.

Capacity Value of Solar Generation

The capacity value of existing and future utility-scale and rooftop PV is 0.

Capacity Value of Demand Response

The estimated megawatt potential from the Residential and Small Business Direct Load Control Program, Commercial and Industrial Direct Load Control Program, and Customer Firm Generation Programs are included in PISP capacity planning.

CONCLUSIONS

The Companies understand the importance of visibility and transparency of the economic commitment and economic dispatch to show the customers that a real effort is being made to reduce the use of fossil fuels and to encourage the use of renewable resources. Creating a website with the same information that RTOs or ISOs use to show price of energy for the market may be misleading if the customer is unaware of the system conditions that is dictating how the generating units are being run. The information that is graphically displayed on the existing Renewable Watch websites is a good starting point for creating visibility and transparency. And the Companies recommend that additional information that is being developed by Blue Planet that displays the system load and the percent of power that each resource group is providing to serve that load also be shown to the customers so that they are able to see over time that less fossil fuel generation is being substituted with less costly generation.