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Maui Energy Storage Study

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Maui Energy Storage Study

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Abstract

This report investigates strategies to mitigate anticipated wind energy curtailment on Maui, with a focus on grid-level energy storage technology. The study team developed an hourly production cost model of the Maui Electric Company (MECO) system, with an expected 72 MW of wind generation and 15 MW of distributed photovoltaic (PV) generation in 2015, and used this model to investigate strategies that mitigate wind energy curtailment. It was found that storage projects can reduce both wind curtailment and the annual cost of producing power, and can do so in a cost-effective manner. Most of the savings achieved in these scenarios are not from replacing constant-cost diesel-fired generation with wind generation. Instead, the savings are achieved by the more efficient operation of the conventional units of the system. Using additional storage for spinning reserve enables the system to decrease the amount of spinning reserve provided by single-cycle units. This decreases the amount of generation from these units, which are often operated at their least efficient point (at minimum load). At the same time, the amount of spinning reserve from the efficient combined-cycle units also decreases, allowing these units to operate at higher, more efficient levels.

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NOMENCLATURE

BESS	Battery Energy Storage System
DOE	Department of Energy
GE	General Electric
GWh	gigawatt-hour
HC&S	Hawaiian Commercial and Sugar Company
HECO	Hawaiian Electric Company
HNEI	Hawaiian Natural Energy Institute
IPP	Independent Power Producer
KPP	Kahului Power Plant
kV	kilovolt
kVAR	kilovolt-amperes reactive
kW	kilowatt
kWh	kilowatt-hour
MECO	Maui Electric Company
MPP	Maalaea Power Plant
MVAR	megavolt-amperes reactive
MW	megawatt
MWh	megawatt-hour
NPV	net present value
NREL	National Renewable Energy Laboratory
PPA	Power Purchase Agreement
PV	photovoltaic
SIS	Solar Integration Study
SNL	Sandia National Laboratories
VO&M	variable operation and maintenance
WIS	Wind Integration Study

EXECUTIVE SUMMARY

The Department of Energy funded Sandia National Laboratories to investigate strategies to mitigate anticipated wind curtailment on Maui, with a focus on evaluating the impact of grid-level energy storage. The installed wind capacity will increase from the existing 30 MW to a planned 72 MW by 2015. Previous studies have indicated that the levels of curtailment on Maui are likely to be significant [1].

This bulk power system study uses hourly production cost modeling to evaluate the operation of the Maui Electric Company (MECO) system in 2015. Wind, solar, and load data used are the same as those being used for the ongoing Solar Integration Study (SIS) being conducted by the National Renewable Energy Laboratory and General Electric for the Hawaiian Electric Company (HECO) [2]. MECO provided data on the planned makeup of the generation fleet in 2015, and on the generator characteristics. In addition, the model used for this study was calibrated against the HECO's P-Month generation planning model to ensure that it accurately reflects the MECO dispatch order.

Study scenarios were developed collaboratively with MECO and HECO personnel. Of the eight scenarios, five add an energy storage system to the reference case, two add a reciprocating engine plant running on biodiesel, and one combines an energy storage system with a new reciprocating engine biodiesel plant.[1]

All of the scenarios maintain or increase the level of installed capacity on the Maui grid. The installed capacity is kept the same by changing the use of the Kahului Power Plant (or KPP) units. The must-run status of the KPP units is currently necessary to maintain active and reactive power on the low-voltage side of the Maui electric grid in the event of a transmission interconnect contingency. Designating KPP as must-run, however, results in an increase in wind curtailment. Any scenario reducing KPP generation must allow for sufficient active and reactive power on the low-voltage side of the network in the event of a contingency.

The level of regulation up (or "spinning") reserves plays an important role in this analysis as the regulation requirement is tied proportionally to the renewable energy generation accepted onto the grid. The more spinning reserve required, the greater the likelihood that additional generators will need to be brought online to provide that reserve. This additional generation can cause wind to be curtailed. In order to provide comparability with the ongoing SIS for Hawaii, this study uses an approximation of the new regulation up requirement as proposed by that project.

Table 1 indicates the level of wind curtailment resulting from the modeling of each scenario. The scenario name reflects the storage or other mitigation project that was added to the reference scenario. The scenarios are not cumulative – in other words, the scenario "10-MW/70-MWh BESS" examines a 10-MW/70-MWh Battery Energy Storage System (BESS) added to the reference case, and does not contain the 10-MW/15-MWh BESS examined in the previous scenario. The "KPP" column shows the operation of the KPP units in each scenario.

[1] Pumped storage hydro was not considered, as MECO/HECO personnel stated that such a plant could not possibly be permitted, constructed, and in operation by 2015. It was therefore not a feasible option for this study.

Table 1. Wind Curtailment by Scenario.

Scenario	KPP	WindGen1	WindGen2	WindGen3	TOTAL
Reference Run	available	4.1%	14.3%	36.1%	16.5%
10-MW/15-MWh BESS	available	3.0%	11.7%	31.8%	14.0%
10-MW/70-MWh BESS	available	1.2%	6.6%	24.1%	9.5%
10-MW/70-MWh BESS, no K4	no K4	1.1%	4.6%	18.3%	7.1%
25-MW Waena	no K3/K4	2.1%	7.3%	24.1%	10.1%
25-MW/175-MWh BESS	no K3/K4	0.3%	1.0%	6.5%	2.3%
25-MW/1200-MWh cryogen	no K3/K4	0.3%	1.1%	6.6%	2.4%
30-MW Waena + 5-MW/35-MWh BESS	not available	1.0%	3.9%	18.1%	6.9%
35-MW Waena + transmission line	not available	2.1%	7.1%	24.0%	10.0%

While Table 1 shows how the various scenario projects impact wind curtailment, it does not address the level of cost savings resulting from the change in system operations. Table 2 contains estimations of the total cost of generation in each scenario, the yearly system savings of each scenario as compared to the reference case, and the project value based on calculated system savings and estimated project cost. The purchase price of wind from each wind farm, based on the Power Purchase Agreements (PPAs), was taken into account in calculating the level of annual savings.

Table 2. Scenario Generation Cost (million USD) and Project Economic Analysis.

Scenario	Diesel	Wind	Diesel + Wind	Annual Savings	Estimated System Cost[2]	Simple Payback (years)	Net Present Value[3]
Reference Run	194.8	45.0	239.8	-	-	-	-
10-MW/15-MWh BESS	190.0	46.3	236.3	3.5	11	3.1	34.4
10-MW/70-MWh BESS	187.7	48.0	235.7	4.1	35	8.5	12.7
10-MW/70-MWh BESS, no K4	185.9	48.6	234.4	5.4	35	6.5	30.6
25-MW Waena	189.8	47.7	237.6	2.2	25	11.4	5.3
25-MW/175-MWh BESS	180.2	49.4	229.7	10.1	87.5	8.7	29.6
25-MW/1200-MWh cryogen	185.2	49.4	234.6	5.2	31.25	6.0	40.3
30-MW Waena + 5-MW/35-MWh BESS	185.5	48.6	234.1	5.7	47.5	8.3	31.0
35-MW Waena + transmission line	188.9	47.7	236.7	3.1	40	12.9	2.7

[2] The Estimated System Cost is an estimate of the capital cost of a system installed in the continental United States in 2015.

[3] Net present value (NPV) calculations assume a 30-year total project life with no terminal value. Those involving battery storage assume a 15-year battery stack life, and that the replacement stack would cost 60% of the initial capital cost of the project.

If one were interested in the project that would provide the greatest return for the least risk (in terms of amount of investment), the 10-MW/15-MWh BESS would likely be that project. If one were interested in the project with the highest estimated NPV, as well as with significant upside should the round-trip efficiency be increased above 50%, then the 25-MW/1200-MWh cryogen storage facility is worth investigating.

The Waena biodiesel plants, if not paired with a storage system, do not rank highly in terms of project NPV. However, one must consider that such a plant allows the system to replace about 150 GWh per year of residual fuel-fired generation at a net reduction in system operational cost – even though it is required to burn biodiesel, which is almost three times more expensive than residual fuel.

Most of the savings outlined in Table 2 are not from replacing constant-cost diesel-fired generation with wind generation. Instead, the savings are achieved by the more efficient operation of the conventional units of the system. Using additional storage for spinning reserve enables the system to decrease the amount of spinning reserve provided by single-cycle units. This decreases the amount of generation from these units, which are often operated at their least efficient point (at minimum load). At the same time, the amount of spinning reserve from the efficient combined-cycle units also decreases, allowing these units to operate at higher, more efficient levels.

In the MECO system of 2015, the ability to do time-of-day shifting facilitates the dispatch of more wind. However, adding additional energy storage volume to a storage device does not appear to significantly increase the efficiency of conventional unit operations. The difference in annual savings between the scenarios that add a 10-MW BESS can be almost entirely attributable to greater wind dispatch and the avoidance of diesel consumption; the savings from conventional generation system efficiencies increase only slightly with increased energy storage volume.

Some important caveats are in order. First, the primary focus of this study was to calculate the annual system savings (compared to the reference case) of each scenario. In order to calculate the financial value of each project, the assumption is made that the annual savings calculated are a reasonable estimate of annual savings going forward. Annual savings going forward can differ from those calculated for 2015 for the following reasons: (1) wind and solar generation amounts or variability could differ from the study year; (2) changes may be made to the conventional generation fleet over time; and (3) fuel prices may vary from those assumed for 2015.

Because they are based on the cost savings calculated for a single year, the study team does not believe that NPV calculations in this report are highly accurate estimates of project value, and would therefore advise that an investment decision should not be made on the basis of these numbers alone. Instead, the study team believes that the NPV calculations here are an indication of how large a project's benefit may be, and are therefore a useful addition to the simple payback calculation.

Second, this study used the spinning reserves specification that has been developed in the ongoing SIS. The specification of spinning reserves is an important factor in how the system is dispatched, and will have an impact on the cost savings yielded by storage projects and new generator additions. At the time this study was conducted, the proposed reserves specification had not yet been thoroughly vetted, and a decision had not been made as to whether it would be adopted – or whether modifications to the specification would be required. In addition, adopting a new reserves specification would require MECO to secure agreement from the independent power producers (IPPs), as the wind farm PPAs contain provisions tied to the existing MECO reserves practice.

While not a focus of this report, the study team did analyze the same storage scenarios using the existing reserves specification. The results of runs were broadly similar, though they show somewhat lower savings as compared to the reference run. At the same time, if MECO decides to maintain the existing reserves specification, it would be prudent to do a detailed review of the results using that specification.

Third, the estimated system cost used here represents an estimation of what such a system might cost in the continental United States in 2015. This does not include any additional costs for transporting and installing the system in Hawaii.

BACKGROUND AND STUDY SCOPE

The MECO Problem

The Maui Electric Company (MECO) is responsible for the safe and reliable delivery of electric energy on the island of Maui. In 2011, the MECO system load peaked just under 200 MW and carried a minimum of around 85 MW. To serve this load, MECO employs firm generation from three main power plants: (1) the Maalaea Power Plant (MPP) with 15 internal combustion units and 4 combustion turbines that run on diesel along with 2 heat recovery units, for a total capacity of 200.65 MW; (2) the Kahului Power Plant (KPP) with 4 steam boilers that run on fuel oil No. 6, for a total capacity of 32.33 MW; and (3) from a co-generation biomass plant owned by the Hawaiian Commercial & Sugar Company (HC&S) that provides a scheduled 12 MW during on-peak hours and 8 MW during off-peak hours. MECO has also entered into Power Purchase Agreements (PPAs) with three different wind farms, Kaheawa I (30 MW), Kaheawa II (21 MW), and Auwahi (21 MW). These are the main power plants on the MECO system. At the time of this report only one of the three wind farms was installed and operating.

With all other constraints remaining equal (must-run units, regulation reserve requirements, minimum generation points, etc.), the estimated wind power production from all three wind farms could result in operations that require significant curtailment of wind energy. The majority of the curtailment happens at night when there are high winds, low load, and must-run units operating at their minimum load levels. An example of this is shown in Figure 1.

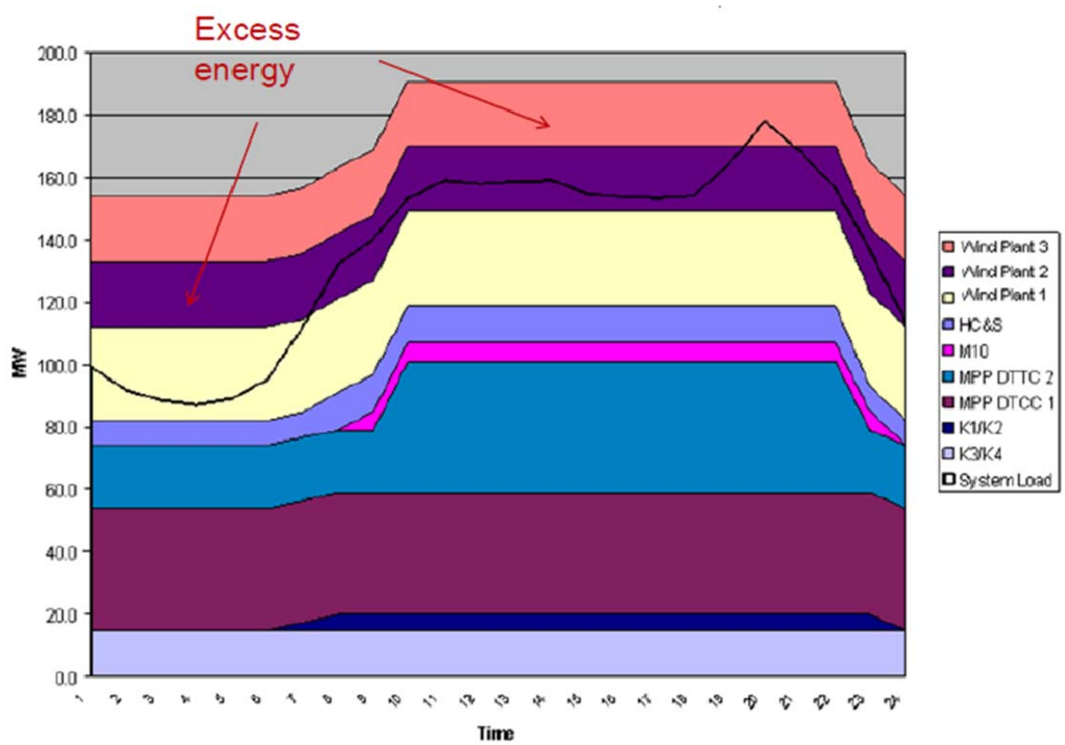

Figure 1. Daily load and generation stack example for Maui.[4]

4 Source: Marc Matsuura and Mat McNeff presentations at UWIG Fall Technical Conference 2011.

The issue of wind curtailment on Maui is related to the challenges around unit commitment and economic dispatch, must-run requirements, reserve requirements and automatic gain control functions, and system topology and reactive power support. These challenges are not independent of each other and need to be examined in unison to develop a robust solution.

The purpose of this study is to examine these challenges and answer the question of *how to best reduce wind energy curtailment with energy storage technologies while maintaining safe and reliable power.*

Analysis Approach

To answer this question, the following process was used:

1. **Research and develop an understanding of the system to be examined.**
   This included obtaining an understanding of the electrical topology of the system, generating assets and characteristics, load characteristics, and operating characteristics. For the Maui system it was important to understand the current operations and assets as well as how those might change for the study year.
2. **Identify current and future needs of the system.**
   For this study this included understanding renewable energy policies and plans, generation reserve requirements, system capacity adequacy requirements, required reactive power support on the system, and projected load growth for 2015. In some cases it might also be necessary to understand the political landscape with regard to renewables and energy regulation to develop plausible scenarios.
3. **Develop and validate system models.**
   This study created a representation of the MECO system in a commercially-available production cost model called PLEXOS. Given system hourly load, hourly wind and solar output data, and spinning reserve requirements as a function of the amount of variable energy dispatched, PLEXOS was used to simulate the unit commitment and dispatch of generation assets. The amount of wind energy curtailed and the overall cost of operating the system were key outputs of the model runs. The Maui PLEXOS model the Sandia National Laboratories (SNL) team created for this study was calibrated against the P-Month generation planning model used by the Hawaiian Electric Company (HECO) to ensure that it accurately reflects the MECO dispatch order.
4. **Develop Study Scenarios.**
   A technical review committee that included employees from MECO and HECO held regular teleconferences to discuss and agree upon the scenarios to be studied. In order to give results that can be compared against a parallel study being performed by the National Renewable Energy Laboratory (NREL) and General Electric (GE), the reference case for this study contains identical assumptions of that of the NREL/GE reference case.
5. **Run and analyze study scenarios.**
6. **Report findings.**

This process can be applied to other systems interested in adding energy storage systems to their generation portfolio.

Study Methodology Strengths and Limitations

There are many advantages to using a production cost model to place a value on a proposed storage facility, or on any other change to a bulk power system.

The primary advantage is that the model can be an accurate representation of system unit commitment and dispatch at the bulk power level, and thus yield detailed and accurate estimates of how changes in the system may impact actual operational cost. Actual load and renewable generation profiles, combined with accurate data on generation unit characteristics, allows the model to use the same information the system operators have when deciding unit commitment and dispatch. The model can be calibrated to mimic actual unit dispatch order, when that dispatch order differs from what one might expect from a strictly economic dispatch. For example, a unit that appears to be economic based on fuel and heat rate may be rarely dispatched because it results in excessive nitrous oxide emissions. Taking this into account increases the realism of the model, and hence makes it more accurate when evaluating hypothetical changes to the system.

A limitation of this study is that the model is deterministic – in other words, whereas system operators in real life do not know exactly how much wind and solar energy will be produced later in the day, the model used here has that information. Having perfect knowledge is useful in scheduling conventional units and in planning for storage charging and withdrawals, and can result in savings higher than those that can be achieved in the real world.

In order to compensate for this perfect knowledge, the model used here is limited to taking into account a 24-hour horizon for planning purposes. In other words, the model only uses the hourly load and variable generation within a 24-hour period to schedule unit commitment and dispatch. If the model were allowed to look ahead a week, for example, then it may find some block of time with high demand and low variable generation, and determine that it would be better to save energy in anticipation of this event than to optimize performance over a 24-hour period. Having perfect knowledge of hourly load and variable generation for an entire week is unrealistic, and likely to result in inflated estimates of storage system value. At the same time, assuming no knowledge beyond the current 24-hour period may be underestimating the value that can be achieved from a storage device with a large volume of storage.

One conclusion that can be drawn from this is that value that is derived from the provision of reserves is of high quality – in other words, it is likely to be realizable in the real world. This is because providing reserves depends on the level of variable generation in real time, and therefore does not rely on the accuracy of a forecast. Value derived from time-of-day shifting (sometimes called “arbitrage”) is of less quality, since unlocking this value does depend on the quality of forecasting future load and variable generation.

System Review Relevant to the Problem

This section provides details about the Maui system that are germane to this study. The electric transmission grid on the island of Maui is comprised of two primary voltage levels: 69 kV and 23 kV. The 69-kV system covers west Maui, south Maui, and much of central Maui, while the 23-kV system covers central Maui and extends radially east to Hana. The two systems are connected in synchronism, yet out of phase, through four zig-zag transformers, one of which operates in the normally open position.

As noted earlier, firm generation comes from three main power plants: MPP, with a total capacity of 200.65 MW; KPP, with a total capacity of 32.33 MW; and, from an independent power producer, the HC&S co-generation biomass plant, which provides a scheduled 12 MW during on-peak hours and 8 MW during off-peak hours. Currently, the Kaheawa Wind Farm, with a 30-MW capacity, is the only installed wind farm on the island. When installed, all 72 MW of wind generation will be located on the 69-kV side of the system.

KPP is the oldest plant in the MECO fleet (units were commissioned from 1948 to 1966) and burns No. 6 oil (also termed “residual fuel oil”). Because KPP is the only source of generation that is connected directly to the 23-kV system, it not only provides a source of generation capacity and active power, but it also provides the necessary reactive power to keep system voltage levels within acceptable limits in the event of an intertie contingency. This function of KPP keeps it categorized as a must-run unit.

Because of the size of the MECO system, it is operated without any contingency or operating reserves. MECO operates only with regulating reserves. With the integration of variable wind energy onto the system, MECO found it necessary to carry additional regulating up reserve. The current formula to calculate the required up reserve is dependent on the amount of delivered wind power to the grid. For delivered wind power less than 30 MW, MECO carries the greater of 6 MW or 50% of delivered wind power. For delivered wind power greater than 30 MW, MECO carries the delivered wind power less 15 MW of regulating up reserve. The down reserve is typically 6 MW at all times. Down regulation requirements of the system are not affected by wind energy levels, but are determined by a load rejection factor.

The two major factors that cause curtailment of wind energy are:

- Baseload must-run units are operating at their minimum load levels and cannot decrease generation any further; and
- There is not enough regulating reserve on the system.

Must-run units, operating at minimum load levels, are a key contributor to nighttime wind energy curtailment. HECO looked at options for removing KPP from must-run status. Without KPP online there are several contingencies that could cause voltage collapse on the 23-kV side of the system. HECO has four recommended solutions for this issue with KPP offline, which are discussed below.

Previous and Current Studies

In 2008, General Electric Energy performed the "MECO Wind Integration Study" (WIS) for MECO to determine the required changes in MECO system operations to increase installed wind capacity to 72 MW. The WIS analyzed four scenarios for wind energy on the Maui system:

Scenario 1: 30 MW (2011 Baseline Model)
Scenario 2: 30-MW and 22.5-MW wind plants
Scenario 3: 30-MW and 21-MW wind plants
Scenario 4: 30-MW and 22.5-MW and 21-MW wind plants

Because MECO has since entered into PPAs for the two additional wind power plants, the SNL team built this study from the results of Scenario 4 above. Based on the results of GE MAPS™ simulations, the estimated wind energy delivered from each wind plant was determined. Curtailment of wind energy happened in such a way that, if needed, the following curtailment order was respected: the 21-MW plant, the 22.5-MW plant, and the 30-MW plant (first-to-last curtailed).

The results of the simulations estimate that 97% of the available energy from the 30-MW plant, 72% of the available energy from the 22.5-MW wind power plant, and only 27% of available energy from the 21-MW wind power plant can be accepted by the system in Scenario 4. Based on a set of simplified estimations, the stakeholders of the WIS selected a set of operational changes and equipment additions for a detailed study. Those changes included removing Kahului Units 1 and 2 from must-run status, creating the current up-regulation requirement calculation, adjusting the down-regulation requirements for the combustion turbines at MPP, and included a 10-MW/20-MWh battery energy storage system (BESS) dedicated to only providing up-regulation. The changes resulted in increased acceptance of wind energy such that 99% was accepted from the 30-MW plant, 84% from the 22.5-MW plant, and 45% from the 21-MW plant.

Additionally, in 2011 HECO studied the impacts to the transmission system with reduced operations at KPP [1]. As discussed earlier, KPP is the only generation source connected to the 23-kV system. By reducing the power provided by KPP, the 23-kV system must draw more power from the 69-kV transmission and tie transformers. HECO examined the system for 10 different cases under normal operating conditions and then again under N-1 contingencies. In general, with KPP offline, the 23-kV system voltage may drop under normal conditions and may drop significantly during contingencies, the reactive power import from MPP increases, overloads on tie transformers occur during contingencies, and overload on some transmission lines may occur.

HECO found that with only Kahului Units 1 and 2 operating that all 69-kV/23-kV tie transformers are operating within an acceptable range; however, low-voltage conditions exist across the 23-kV system. Additionally, the total system losses increase by 12.5%. With all Kahului units offline, HECO found that during normal operating conditions all the tie transformers are operating within an acceptable range. For the worst N-1 contingency without any Kahului units online, the 69-kV/23-kV tie transformers begin to overload and undervoltage conditions are seen across the majority of the 23-kV system.

HECO developed three alternatives to alleviate these issues:

- Alternative 1: Build a new 69-kV transmission line from Waiinu to Kanaha Substation;
- Alternative 2: Add a second circuit of 69-kV transmission lines from MPP to Waiinu, from MPP to Puunene, and from MPP to Kanaha; and
- Alternative 3: Upgrade the existing 23-kV Waiinu to Kanaha line to a 69-kV line.

HECO concluded that Alternative 1 would mitigate the undervoltage and overloading conditions for all KPP units offline, but would not be sufficient if both KPP and HC&S are offline. Alternative 2 requires the addition of three new lines to create the double circuits, which is likely the least economical solution but provides adequate redundancy for each of the three worst N-1 contingencies. Alternative 3 performed similarly to Alternative 1 in that it would not be sufficient to handle tie transformer overloads with both KPP and HC&S offline. Alternative 3 would also require the conversion of some 23-kV substations to 69 kV.

STUDY SCENARIOS AND RESERVE REQUIREMENTS

Study Scenarios

The study scenarios were selected for this study in consultation with MECO/HECO personnel. They are listed in Table 3 below.

Table 3. Study Scenarios.

Scenario Name	KPP Operations	Scenario Characteristics of Interest
Reference run		
10-MW/15-MWh battery	unchanged	spinning reserve value only
10-MW/70-MWh battery	unchanged	spin + arbitrage
10-MW/70-MWh battery, no K4	K4 not available	spin + arbitrage + K4 off
25-MW Waena	K3/K4 not available	spin (w/minimum output) + K3/K4 off
25-MW/175-MWh battery	K3/K4 not available	spin + arbitrage + K3/K4 off
25-MW/1200-MWh cryogen	K3/K4 not available	spin (w/min output) + large arbitrage + K3/K4 off
30-MW Waena + 5-MW/35-MWh battery	KPP not available	flexible diesel (spin) + 5 MW spin + KPP off
35-MW Waena + transmission line	KPP not available	flexible diesel (spin) + KPP off

In this table, “KPP Operations” refers to how KPP is operated in each scenario. “No Change” means that the plant operates as it does in the Reference case – with Units 1 and 2 (K1 and K2) operating on alternate days between 2 p.m. and 11 p.m., and Units 3 and 4 (K3 and K4) on must-run at all times. The “Scenario Characteristics of Interest” refers to what the study team was interested in when selecting a given scenario, where “spin” refers to spinning reserves, and “arbitrage” refers to time-of-day shifting.

The scenario selection criteria was to investigate different options for mitigating wind curtailment and reducing cost, while maintaining the amount of installed capacity. The scenarios chosen, therefore, leave the MECO system with close to the same amount of installed capacity as in the reference case. While reducing must-run generation below the amounts shown would have been possible in several of these scenarios (and would have further reduced the cost of operating the system), it would introduce the risk that MECO might not be able to meet load under certain conditions (such as when one combustion turbine is out for maintenance, and then a second one experiences a forced outage). Requiring the capacity to be the same as the reference case means that the resulting savings is not the result of taking more or less risk of losing load, but is the result of changes in how the system can be operated.

The study team was primarily interested in scenarios involving storage, and in understanding how much value is contributed by spinning reserves versus time-of-day shifting.[5] However, since storage is not the only option available to decrease wind curtailment, several scenarios involving a new, efficient diesel generation facility were included.

The generation units envisaged at Waena would be of the reciprocating engine type, which are high in efficiency for a single-cycle plant, and perhaps more importantly, are highly flexible, in that they can be started quickly (within 3 to 5 minutes) and can undergo several stop/start cycles per day without incurring significant maintenance costs. The minimum capacity assumed on the Waena units is 30% of installed capacity, and the modeled heat rate curves were based on communications with a manufacturer of these types of engines. In all scenarios involving this plant, it is assumed to operate on biodiesel, which is almost twice as expensive as low-sulfur diesel (and three times as expensive as residual fuel oil).[6] The cost savings presented for these scenarios, therefore, are less than they would be were this plant allowed to use low-sulfur diesel.

A 75% round-trip efficiency is assumed for the scenarios involving batteries capable of time-of-day shifting. This is what one would expect for sodium sulfur batteries, which are currently the most likely technology where 7-hour storage is called for.

In addition, the model is constrained to doing a 24-hour optimization for dispatch. In cases involving storage units capable of time-of-day shifting, dispatch includes deciding when to use the battery for spinning reserve and when (and how) to use it for time-of-day shifting. In the view of the project team, allowing weekly optimization would allow the model (given perfect information on load and variable generation) to perform better than system operators could likely do in reality, and so would lead to an overly optimistic assessment of the value of time-of-day shifting.

The **10-MW/15-MWh battery** scenario explores the additional value of 10 MW of spinning reserve from a battery system. The advantage of this is that the needed reserve can be supplied without starting a diesel unit (which operates at a minimum output level). At times of high wind and low load, this minimum output level can further contribute to wind curtailment. The battery in this scenario is not allowed to participate in time-of-day shifting. This battery could be placed at any point in the MECO system with sufficient transmission capacity. No other changes to the reference case are made.

The **10-MW/70-MWh battery** scenario is similar to the previous scenario, but allows the battery to do time-of-day shifting. In this way, the incremental value of the ability to do time-of-day shifting can be determined. In deciding when to use the battery for spinning reserve and when (and how) to use for time-of-day shifting, the model is constrained to doing a 24-hour optimization. As in the previous scenario, this battery could be placed at any location in the

[5] Pumped storage hydro was not considered, as some MECO/HECO personnel estimated that it could take as long as 10 years to go through the permitting and construction process. As this plant could not be available for 2015, it was not a feasible option for this study.

[6] The MECO/HECO team informed us that any new diesel-fueled power plant on Maui would, in all likelihood, be permitted on the condition that it burn biodiesel. All existing units use either low-sulphur diesel or ultra-low sulphur diesel, with the exception of the Kahului units, which use residual fuel oil.

MECO system with sufficient transmission capacity. No other changes to the reference case are made.

The **10-MW/70-MWh battery + K4 offline** scenario is the same as the previous scenario, but takes Kahului Unit 4 offline. It can be considered that this unit is mothballed or decommissioned. For this scenario, the key point is that it is unavailable to the model to be dispatched. This is expected to decrease system cost, primarily because reducing must-run generation should allow for more wind power to be dispatched. The addition of the 10-MW battery, and the removal of Kahului Unit 4, gives the system close to the same capacity as in the reference case.

The **25-MW Waena Plant** scenario places a reciprocating engine plant (5 units of 5-MW capacity each) running on biodiesel on the 69-kV side of the network.[7] This allows Kahului Units 3 and 4 to be taken offline, while maintaining roughly the same installed capacity as in the reference case. Again, by "offline," we mean that these units are unavailable for system dispatch. Since Kahului Units 1 and 2 would still be in operation (on their alternate day schedule), there would likely be enough real power production on the 23-kV side of the network in the event of an interconnect contingency (between the 23-kV and 69-kV networks). However, power factor correction would likely be needed, since the other Kahului unit could not be started quickly enough. Therefore, MECO would likely need to install a 10-MVAR capacitor bank or the functional equivalent on the 23-kV side of their network in order to deal with this contingency.

The **25-MW/175-MWh battery** scenario places a battery capable of up to 25 MW of regulation as well as time-of-day shifting on the grid. Kahului Units 3 and 4 are taken offline in this scenario. If placed on the 23-kV side of the system, power factor issues in the event of a transmission line contingency could be addressed with proper storage system inverter design. The inverter could be made capable of modifying the power factor of power on the grid (in other words, it would not have to use stored energy to "produce" reactive power). If placed on the 69-kV side of the system, it would be necessary to install a 10-MVAR capacitor bank or the functional equivalent on the 23-kV side of their network in order to deal with an interconnect contingency.

The **25-MW/1200-MWh** cryogen scenario places a cryogen storage system with 25 MW of liquefaction capacity as well as 25 MW of generation capacity on the grid, and takes K3/K4 offline. This type of system relies on standard liquefaction technology to produce liquid air or nitrogen, stores the liquid in a thermally insulated container, and then uses a gas expansion turbine to generate electricity from the expansion of the liquid to the gas. It is assumed that this is a single-turbine unit with a minimum output level of 8 MW. If placed on the 23-kV system, the unit could produce enough active and reactive power to deal with an interconnect contingency – in order to do this, this scenario specifies a minimum of 50 MWh in storage, so that the unit could always generate on-peak in the event of such a contingency. The cryogen storage system is assumed to have a round-trip efficiency of 50%, which is what one

[7] The MECO/HECO team informed the study team that it has already been determined that the next power plant to be built on Maui would have to be built on the 69-kV side (high-voltage side) of the Maui network.

manufacturer expects if the system cannot be co-located with another industrial process. If it can be co-located with a source providing heat, the efficiency could be increased.

The **30-MW Waena Plant + 5-MW/35-MWh battery** scenario places a new Waena plant (6 units of 5 MW each) on the 69-kV network, and takes Kahului completely offline. In order to avoid building an additional transmission line (to mitigate an interconnect contingency), a 5-MW/35-MWh battery system is placed on the 23-kV network. In addition, a 10-MVAR capacitor bank or the functional equivalent on the 23-kV side of their network would be necessary in order to deal with an interconnect contingency.

Finally, the **35-MW Waena Plant + New Transmission Line** scenario calls for a new Waena plant (7 units of 5 MW each) on the 69-kV network, takes Kahului completely offline, and calls for a new transmission line to be built between the 23-kV and 69-kV networks. The addition of this line would prevent overloads in the remaining interconnections in the event of the failure of a single interconnection. Based on MECO/HECO analysis, it is likely that no additional sources of reactive power (such as capacitor banks) would be needed on the 23-kV network given the additional transmission line.

Reserve Requirements

The level of regulation up (or "spinning") reserves plays an important role in this analysis. When efficient generators carry reserve, not only do they operate at a less-efficient output level, other (less-efficient) generators must be dispatched to make up the shortfall in generation. The more spinning reserve required, the greater the likelihood that generators with a minimum output will need to be brought online to provide that reserve. This additional generation on the system can exacerbate wind curtailment.

Currently, the formula for calculating spinning reserves is solely a function of the amount of wind energy dispatched.[8] We have called this the "status quo" reserves requirement. This reserves formula is given in Table 4.

Table 4. Status Quo Spinning Reserves Requirement.

Wind Power Dispatched	Spinning Reserves Required
Less than 12 MW	6 MW
Between 12 MW and 30 MW	WIND/2
Between 30 MW and 65 MW	WIND – 15 MW
Over 65 MW	50 MW

8 Historically, MECO has not required spinning reserves in the event of a contingency. They use load shedding for this purpose.

The ongoing Solar Integration Study (SIS) has produced a proposed reserves requirement, in the form of a table function.[9] This function depends on the total amount of variable generation online (that is, wind plus solar), as opposed to being a function of wind only. That function, along with the status quo requirement, is illustrated in Figure 2.

The proposed reserves requirement calls for more spinning reserve at lower levels, and less spinning reserve at higher levels, of variable generation than does the status quo requirement.

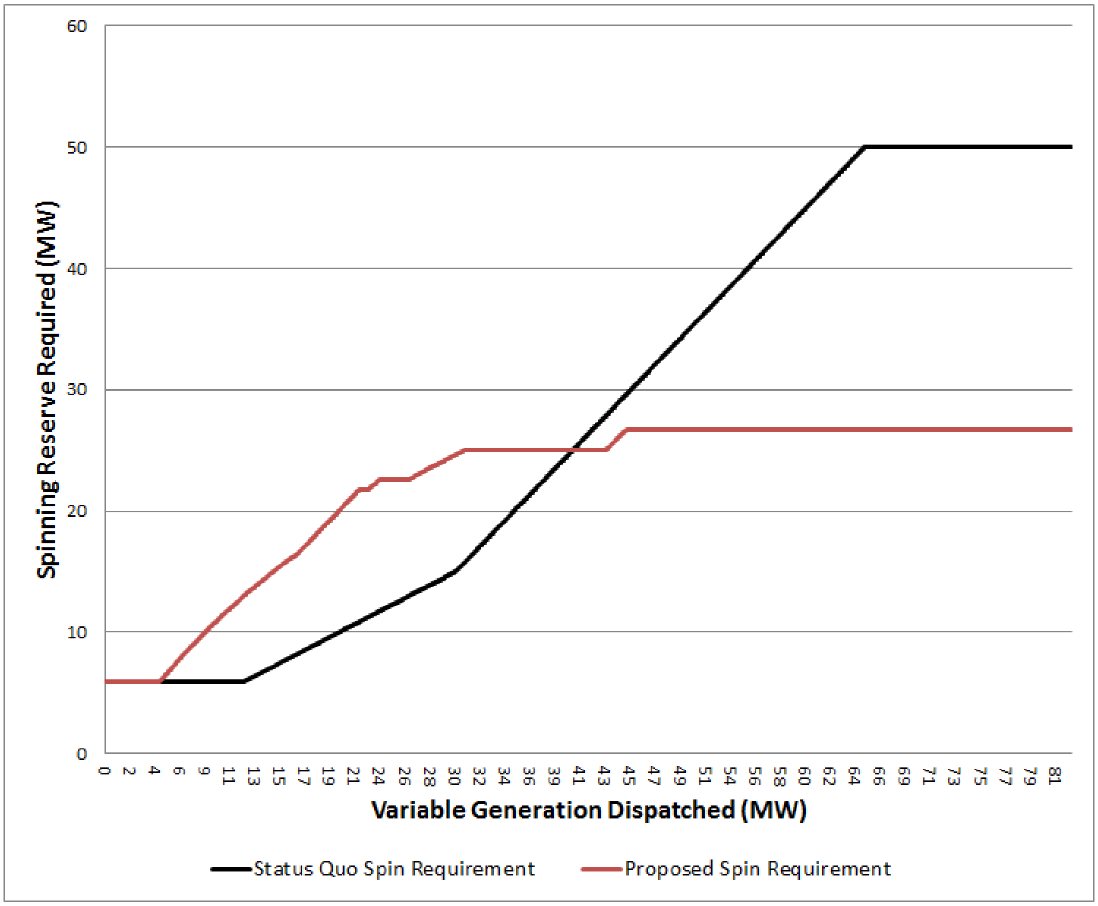

Figure 2. Status quo versus proposed spinning reserves requirements.

MECO and HECO requested that this study use the reserve requirement recently proposed by GE, in order to provide comparability with the ongoing SIS. All results discussed in this report, unless otherwise noted, were determined using the new reserve requirement.

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[9] Note: The actual table function proposed by GE goes down to 0 MW of reserve required at 0 MW of renewable output. MECO/HECO personnel indicated to us that they would not operate the system below 6 MW of spinning reserve, no matter how low renewable generation output falls. Therefore, the study team modified the GE table function to reflect this.

Since the study team was unable to use a table function for the level of spinning reserve required in the production cost modeling, it was necessary to use a formula to approximate this function.

While the formula used is an approximation, the study team feels that it is both a reasonable representation of what is called for in the new reserve specification, as well as being a formula that would be easy for MECO system operators to follow. This approximation is detailed in Table 5.

Table 5. "New" Spinning Reserves Requirement Approximation.

Renewables Dispatched	Spinning Reserves Required
Less than 6 MW	6 MW
6 MW to 26.8 MW	Equal to level of variable generation dispatched
Over 26.8 MW	26.8 MW

The proposed spinning reserves requirement approximation is illustrated in Figure 3, which compares it with the proposed reserves requirement as developed in the ongoing SIS.

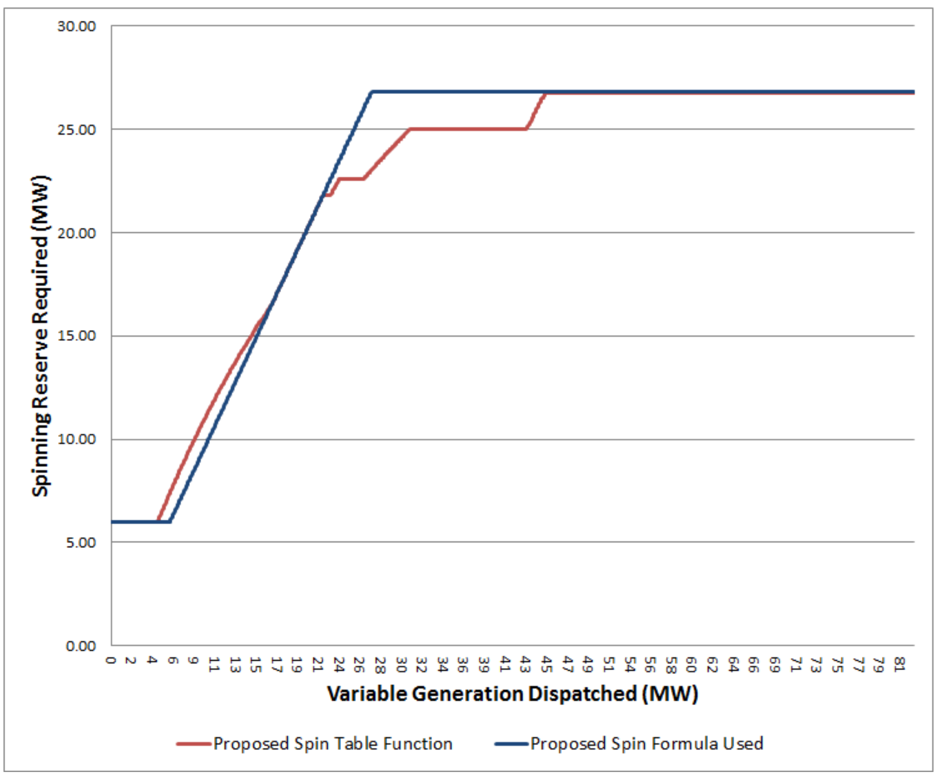

Figure 3. Proposed spinning reserves specification vs. formula used in analysis.

While not presented in this report, the study team tested the same storage scenarios with the status quo reserves requirement. Though the annual savings (as compared to the reference run) using the status quo reserves requirement are not identical to those calculated with the new requirement, in general they are close. If MECO decides against adopting the new reserves requirement, it would be prudent to review the detailed results of the calculations using the status quo requirement, or to redo the runs based on whatever new reserves specification that may be adopted.

RESULTS

This section of the report contains a discussion of the study results. The discussion is organized into two sections – a summary section, which presents the overall results and compares and contrasts the scenario results, and an individual scenario section, which contains a more in-depth discussion of each scenario.

Summary Results

Table 6 through Table 11 provide insight into the results of each scenario. Along with the scenario name and Kahului (KPP) operations that are a part of each scenario, Table 6 displays the wind curtailment that resulted from each scenario. Each of the scenarios provides additional system flexibility, whether through additional spinning reserve, the ability to use energy storage for time-of-day shifting, or increased generating unit flexibility. It is therefore no surprise that each scenario allows the system to accept more wind than the reference run.

Table 6. Wind Curtailment (in percent) by Scenario.

Scenario Name	KPP	WindGen1	WindGen2	WindGen3	TOTAL
Reference Run	available	4.1%	14.3%	36.1%	16.5%
10-MW/15-MWh BESS	available	3.0%	11.7%	31.8%	14.0%
10-MW/70-MWh BESS	available	1.2%	6.6%	24.1%	9.5%
10-MW/70-MWh BESS, no K4	no K4	1.1%	4.6%	18.3%	7.1%
25-MW Waena	no K3/K4	2.1%	7.3%	24.1%	10.1%
25-MW/175-MWh BESS	no K3/K4	0.3%	1.0%	6.5%	2.3%
25-MW/1200-MWh cryogen	no K3/K4	0.3%	1.1%	6.6%	2.4%
30-MW Waena + 5-MW/35-MWh BESS	not available	1.0%	3.9%	18.1%	6.9%
35-MW Waena + transmission line	not available	2.1%	7.1%	24.0%	10.0%

As Table 6 shows, the curtailment order of the wind generators is considered in the model runs. In the 10-MW/15-MWh BESS scenario, the battery can only contribute to spinning reserve. This yields a total wind curtailment of 14%, as opposed to the 16.5% of the reference run. The addition of the ability to do time-of-day shifting, which is the only difference between this scenario and the 10-MW/70-MWh BESS scenario, allows for an additional drop in total curtailment – down to 9.5%. Taking this same battery system and removing Kahului Unit 4 from service reduces the amount of inflexible baseload generation on the system, and thus further decreases curtailment, to 7.1% for the year.

Placing a flexible 25-MW biodiesel-fired power plant at Waena does not add any storage to the reference run, yet yields a total wind curtailment of 10.1%. This is due to taking a large amount of inflexible baseload generation off of the grid (Kahului Units 3 and 4), and installing a flexible, quick-start power plant where each of the five units can operate at a minimum of 1.5 MW, thus providing 3.5 MW of spinning reserves.

The 25-MW/175-MWh BESS yields the lowest amount of annual wind curtailment – 2.3%. The 25-MW/1200-MWh Cryogen storage facility comes close to this same level of wind curtailment, providing for total wind curtailment of 2.4%.

The combination of a 30-MW Waena power plant and a 5-MW/35-MWh battery results in wind curtailment of 6.9%, while the 35-MW Waena power plant plus transmission line results in wind curtailment of around 10%. The latter result is roughly the same as in the 25-MW Waena power plant scenario, which indicates that the additional spinning reserve provided by the larger plant cannot be used to reduce wind curtailment – and that eliminating the baseload production of Kahului Units 1 and 2 is also not of much help in increasing the amount of wind power dispatched.

Rather than displaying the percent of annual wind curtailment, Table 7 shows the amount of generation from each wind farm (and in total) resulting from each of the runs. As expected, the amount of improvement is greatest at WindGen3, which is the wind farm that is the first in order of curtailment. WindGen1 is not curtailed much in the reference case, and so has little room for improvement.

Table 7. Wind Generation (in GWh) by Scenario.

Scenario	KPP	WindGen1	WindGen2	WindGen3	TOTAL
Reference Run	available	123.4	75.0	57.8	256.3
10-MW/15-MWh BESS	available	124.9	77.3	61.7	263.9
10-MW/70-MWh BESS	available	127.3	81.8	68.6	277.7
10-MW/70-MWh BESS, no K4	no K4	127.4	83.6	73.9	284.9
25-MW Waena	no K3/K4	126.1	81.2	68.6	275.9
25-MW/175-MWh BESS	no K3/K4	128.3	86.7	84.6	299.6
25-MW/1200-MWh cryogen	no K3/K4	128.3	86.6	84.4	299.4
30-MW Waena + 5-MW/35-MWh BESS	not available	127.5	84.2	74.1	285.7
35-MW Waena + transmission line	not available	126.0	81.4	68.7	276.1

Table 8 examines generation by fuel type. Here wind is combined with solar, which is distributed photovoltaic (PV) energy and cannot be curtailed because of its distributed nature – and is the same in all scenarios. Biomass, which is used to fire the HC&S facility that MECO does not own but purchases power from, is also the same in all runs, given the fixed nature of the PPA. Therefore, generation from biomass and biodiesel are reported together. On Maui, residual diesel is burned only at the Kahului plant. Finally, the "Other Diesel" category combines generation from plants fired by standard diesel and those fired by ultra-low sulfur diesel fuel.

In calculating the percent renewable generation in each run, the study team counted generation from wind, solar, biomass, and biodiesel plants as being renewable.

Table 8. Scenario Generation (in GWh) by Fuel Type.

Scenario (Note: figures in GWh, unless otherwise noted)	Residual Diesel	Other Diesel	Biomass[10] +Biodiesel	Wind+ Solar	Total	Renewable Generation (%)
Reference Run	148	734	96	286	1,264	28.4%
10-MW/15-MWh BESS	150	724	96	294	1,264	29.0%
10-MW/70-MWh BESS	150	714	96	308	1,268	30.0%
10-MW/70-MWh BESS, no K4	79	778	96	315	1,268	30.5%
25-MW Waena	9	832	118	306	1,264	31.6%
25-MW/175-MWh BESS	9	839	96	330	1,274	31.5%
25-MW/1200-MWh cryogen	8	865	96	329	1,299	30.9%
30-MW Waena + 5-MW/35-MWh BESS	-	834	117	316	1,266	32.3%
35-MW Waena + transmission line	-	833	125	306	1,264	32.2%

Of note is that the scenario that produced the lowest levels of wind curtailment, the 25-MW/175-MWh BESS scenario, does not produce the highest levels of renewable generation. That distinction goes to the 30-MW Waena + 5-MW/35-MWh BESS scenario. Though this scenario does not dispatch as much wind as the 25-MW/175-MWh BESS scenario, there are lower levels of system losses, and the biofuel generation of the new Waena plant counts towards renewable generation.

Table 9 provides information about the annual savings, as compared to the reference case, resulting from the inclusion of the resource specified in each scenario examined. The crux of this study is the calculation of this number. In order to calculate this number, one has to take into account how much more wind generation is possible, how much less diesel generation would be needed, what losses would result in using the particular storage technology specified, and how the cost of operating the conventional generation fleet changes as it is dispatched differently. The detail required to take these factors into account is the reason a production cost model was used for this study.

[10] Note: The "Biomass + Biodiesel" column here categorizes the HC&S plant as a biomass plant, and puts all of its production in this category. However, the HC&S power plant burns both biomass and coal. MECO has indicated that the plant uses biomass for roughly 75% of its power production, with the remaining 25% from coal. The percent renewable generation in this table, therefore, counts 75% of the production of the HC&S plant as renewable.

Table 9. Annual System Savings From Scenario Projects.

Scenario (Note: figures in millions of USD)	Cost of Diesel Generation	Cost of Wind Generation	Total Diesel + Wind Cost	Annual Savings (compared to reference run)
Reference Run	194.8	45.0	239.8	-
10-MW/15-MWh BESS	190.0	46.3	236.3	3.5
10-MW/70-MWh BESS	187.7	48.0	235.7	4.1
10-MW/70-MWh BESS, no K4	185.9	48.6	234.4	5.4
25-MW Waena	189.8	47.7	237.6	2.2
25-MW/175-MWh BESS	180.2	49.4	229.7	10.1
25-MW/1200-MWh cryogen	185.2	49.4	234.6	5.2
30-MW Waena + 5-MW/35-MWh BESS	185.5	48.6	234.1	5.7
35-MW Waena + transmission line	188.9	47.7	236.7	3.1

While the main goal of this exercise was to calculate an annual savings resulting from adding the scenario resources, it is useful to understand exactly where those savings are coming from. As each of the scenarios has less wind curtailment than does the reference run, our assumption was that the savings are primarily coming from purchasing more wind, and spending less on diesel generation.

Table 10 examines this assumption by calculating what would have been saved by simply increasing wind generation and decreasing diesel generation by the amount resulting in each scenario run, and comparing this with the total level of savings achieved. The difference is that the former calculation does not include any reduction in diesel generation cost from the more efficient dispatch of conventional units, whereas the total level of savings (as indicated in Table 9) does. In calculating what would have been saved by simply increasing wind generation and decreasing diesel generation, the cost of diesel generation per kWh from the reference run is used.

As can be seen, only in one scenario (the 25-MW Waena power plant scenario) are savings from increased wind generation alone the main component of total savings. In all other scenarios, savings from more efficient dispatch of the conventional generation fleet make up the largest component of total savings. This more efficient dispatch is enabled by the provision of spinning reserve by the storage device. The efficient combined cycle units, which typically provide spinning reserve, can operate at higher output levels with a storage system in place. This both increases the efficiency of the combined cycle units, and allows the system to produce less power on marginal units. This also means that fewer starts of these marginal units are required.

Table 10. Breakdown of Annual System Savings.

Scenario (Note: figures in millions of USD, unless otherwise noted)	Change in Diesel Gen (GWh)	Change in Wind Gen (GWh)	Marginal Diesel Gen cost	Marginal Wind Gen cost[11]	Expected cost diff	Actual cost diff	% due to increased system efficiencies
Reference Run	-	-	-	-	-	-	-
10-MW/15-MWh BESS	(7.7)	7.6	(1.7)	1.4	(0.31)	(3.5)	91%
10-MW/70-MWh BESS	(17.4)	21.4	(3.8)	3.0	(0.81)	(4.1)	80%
10-MW/70-MWh BESS, no K4	(24.7)	28.6	(5.5)	3.6	(1.85)	(5.4)	66%
25-MW Waena	(19.7)	19.6	(4.3)	2.8	(1.59)	(2.2)	28%
25-MW/175-MWh BESS	(33.5)	43.3	(7.4)	4.5	(2.96)	(10.1)	71%
25-MW/1200-MWh cryogen	(8.1)	43.1	(1.8)	4.4	2.66	(5.2)	151%
30-MW Waena + 5-MW/35-MWh BESS	(27.4)	29.4	(6.1)	3.7	(2.40)	(5.7)	58%
35-MW Waena + transmission line	(19.9)	19.8	(4.4)	2.8	(1.61)	(3.1)	48%

Having calculated an annual savings resulting from the inclusion of each resource, this can be combined with an estimation of the capital cost of each resource to produce some financial metrics to assist in evaluating each project. Table 11 displays two such metrics, simple payback and net present value (NPV).

For all of the storage systems apart from the cryogen system, the capital cost was estimated from a draft version of the Department of Energy (DOE) *Storage Handbook*. The *Storage Handbook* features a survey of storage system manufacturers, and estimates the cost of a system delivered to the continental United States. The cryogen system costs were derived from information from a manufacturer's literature.[12] The Waena plant cost estimates are based on discussions with a manufacturer for what such a system might cost as built in the continental United States.

[11] Note: The marginal wind generation cost in this table was calculated based on the cost per kWh owed by MECO to each of the wind farms based on the PPAs currently in place.

[12] The manufacturer's website indicates the cost of their system with a 10-hour storage configuration. The SNL study team made some assumptions about how much additional hours of storage might add to the capital cost. These assumptions may underestimate the actual cost of such a resource.

Table 11. Scenario Project Evaluation

Scenario	Annual Savings	Estimated System Cost	Simple Payback (years)	NPV[13]
Reference Run	-	-	-	-
10-MW/15-MWh BESS	3.5	11	3.1	34.4
10-MW/70-MWh BESS	4.1	35	8.5	12.7
10-MW/70-MWh BESS, no K4	5.4	35	6.5	30.6
25-MW Waena	2.2	25	11.4	5.3
25-MW/175-MWh BESS	10.1	87.5	8.7	29.6
25-MW/1200-MWh cryogen	5.2	31.25	6.0	40.3
30-MW Waena + 5-MW/35-MWh BESS[14]	5.7	47.5	8.3	31.0
35-MW Waena + transmission line	3.1	40	12.9	2.7

An important caveat is in order. The primary focus of this study was to calculate the annual system savings (compared to the reference case) of each scenario. In order to calculate the financial value of each project, the assumption is made that the annual savings calculated is a reasonable estimate of annual savings going forward. Annual savings going forward can differ from those calculated for 2015 for the following reasons: (1) wind and solar generation amounts or variability could differ from the study year; (2) changes may be made to the conventional generation fleet over time; and (3) fuel prices may vary from those assumed for 2015.

Because they are based on the cost savings calculated for a single year, the study team does not believe that NPV calculations in this report are highly accurate estimates of project value, and would therefore advise that an investment decision should not be made on the basis of these numbers alone. Instead, the study team believes that the NPV calculations here are an indication of how large the benefit of a project may be, and are a useful addition to the simple payback calculation (which is better at indicating a project's risk).

If one were interested in the project that would provide the greatest return for the least risk (in terms of amount of investment), the 10-MW/15-MWh BESS would likely be that project. If one were interested in the project with the highest estimated NPV as well as with significant upside should the round-trip efficiency be increased above 50%, then the 25-MW/1200-MWh cryogen storage facility is worth investigating.

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[13] NPV calculations assume a 30-year total project life with no terminal value. Those involving battery storage assume a 15-year battery stack life, and that the replacement battery stack would cost 60% of the initial project capital cost. If the batteries do not last this long, or end up costing more than assumed, the NPV would be less than that calculated here.

[14] Note: This scenario requires 10 MW of reactive power on the 23-kV side. This system cost estimate does not include the cost of the capacitor bank. This is likely to be less than 2% of the overall project cost.

The Waena biodiesel plant allows the system to replace about 150 GWh per year of residual fuel-fired generation at a net reduction in system operational cost – even though it is required to burn biodiesel, which is almost three times more expensive than residual fuel.

Individual Scenario Discussion

10-MW/15-MWh BESS

At first glance, it seems surprising that the addition of a 10-MW battery system providing spinning reserve could yield an annual savings of $3.5 million.

The battery system facilitates the dispatch of an additional 7.6 GWh of wind power, which allows for a reduction in diesel-fired generation of roughly the same amount. As the marginal cost of this additional wind is about 18 cents/kWh, and the cost of diesel-fired generation in the reference run was about 22 cents/kWh, there is a net savings of 4 cents/kWh. Multiplied by 7.6 GWh, this yields a savings from increased wind dispatch alone of about $0.3 million.

Examining the remaining savings of $3.2 million shows that it comes from the more efficient operation of the conventional generators on the system. The system weighted average heat rate is roughly 1% lower in this scenario than in the reference run. In addition, there are almost 200 fewer unit starts in this scenario as compared with the reference case, saving on startup cost. This more efficient system operation allows the cost of diesel generation to drop by $4.8 million (as opposed to the drop of $1.7 million one would expect from decreasing generation by 7.6 GWh while holding fixed the cost of generation at 22 cents/kWh). When offset by an additional $1.3 million in wind purchases, this yields a net savings of $3.5 million over the year.

This increase in weighted average heat rate is from increasing generation at more efficient generators (the Maalaea combined cycle units), and decreasing generation at less efficient units. The battery system enabled this increase in generation at the combined cycle units, as it reduced the requirement on them to provide spinning reserve.

The increase in generation at the efficient generators has a second effect – as they can be operated at higher levels of output, their average heat rate decreases. In this case, M14, 15, and 16 in dual-train mode goes from an average heat rate in the reference case of about 8,860 BTU/kWh to an average heat rate of about 8,790 BTU/kWh in this scenario. Similarly, M17, 18, and 19 in dual-train mode goes from an average heat rate in the reference case of about 8,510 BTU/kWh to an average heat rate of about 8,480 BTU/kWh in this scenario. Therefore, not only does the system gain from having a larger fraction of generation from efficient plants, the fact that these plants are dispatched at higher levels increases the efficiency of the units themselves.

Since the $3.5 million in annual savings is a result of the provision of spinning reserves alone from the battery system, these savings should be achievable by system operators. Savings that rely on time-of-day shifting, on the other hand, depend on the accuracy of load and variable generation forecasting, and therefore may be more difficult to achieve in the real world.

For a risk-averse decision-maker, this project would seem to be attractive. It requires the lowest level of investment of any of the scenarios examined, while providing the second-highest NPV of the scenarios. The short simple payback time of roughly 3 years means that the capital cost can be recouped quickly – there is little risk that the generation mix would change in a significant way before the project cost is recovered. Also, the savings should be achievable independent of load and variable generation forecasting accuracy.

10-MW/70-MWh BESS

The only difference between this scenario and the previous one is that here the battery system is capable of providing both spinning reserve and time-of-day shifting. This additional capability does not significantly increase the annual system savings, however. The annual savings here are $4.1 million, as opposed to $3.5 million in the previous scenario.

Why is it that in this scenario adding the capability to do time-of-day shifting allows the system to save only $0.6 million more than when the battery system could only provide spinning reserve? This seems surprising, as wind curtailment drops from 14% in the previous scenario to 9.5% in this one – an improvement of 4.5%. This translates to 21.4 GWh more wind than in the reference run. The cost of this additional wind is about $3 million, which means that the marginal cost of this extra amount of wind is roughly 14 cents/kWh, or about 4 cents/kWh cheaper than the price of the marginal wind generation in the previous scenario. This reduction in wind cost is a result of the structure of the PPAs with WindGen2 and WindGen3, which stipulate that within a given year, energy dispatched above certain amounts is sold at a discounted rate.

The $3 million cost for additional wind is offset by a reduction in diesel-fired generation of about 17 GWh, which would yield a savings of almost $4 million at the reference run average diesel-fired generation cost of 22 cents/kWh) – for a net decrease of about $1 million. Instead, the cost of diesel-fired generation dropped by $7.2 million as compared to the reference case, which when offset by the cost of additional wind generation yields a total annual savings of about $4.1 million.

Again, this savings is mainly from increased efficiencies in operating the conventional generators in the system, but here a higher portion of the savings (about 25%) is from producing additional lower-cost wind and avoiding the production from higher-cost diesel-fired generators.

10-MW/70-MWh BESS, no K4

The only difference between this scenario and the previous one is the operation of Kahului Unit 4, which is not available here. One would expect that eliminating generation from this baseload generator would allow the system to dispatch more wind at night, when load is low and must-run units serve to crowd-out wind during periods of high production.

In fact, wind curtailment drops further, to a total of 7.1% for the system – this represents a 2.4% decrease in annual wind curtailment compared with the previous scenario. Here, 28.6 GWh of additional wind power is dispatched as compared to the reference run. The marginal cost of this additional wind is around 12.6 cents/kWh – about 1.5 cents/kWh cheaper than the cost of the additional wind in the previous scenario. Again, this is because of the structure of the PPAs with WindGen2 and WindGen3, which provide for discounts based on the volume of power dispatched.

As compared with the reference case, a savings of roughly $9 million on diesel-fired generation, combined with an additional expense of about $3.6 million on wind power purchases, yields a net savings of about $5.4 million. This amounts to an increase in savings of about $1.3 million above the previous scenario, where Kahului Unit 4 was operated in must-run status as usual.

25-MW Waena

This scenario uses no additional storage, but instead places an efficient, quick-start diesel-fired plant at Waena. The study team was informed by MECO/HECO personnel that this plant would be required to operate on biodiesel. This requirement puts the plant at a distinct disadvantage relative to the other conventional generation on the system, as biodiesel is roughly twice as expensive as regular diesel fuel, and almost four times as expensive as the residual fuel oil that is used at the Kahului plant.

One might therefore expect that in this scenario, where the largest units of Kahului (Units 3 and 4) are made unavailable to the system, the overall cost of generation would go up. In fact, it goes down – by $2.2 million as compared with the reference case.

The savings achieved is not from the new Waena plant replacing the generation lost from the Kahului units – this would indeed result in an increase in system cost. (The Waena plant produces only 21.5 GWh of power in this scenario, as opposed to the 140 GWh the Kahului Units 3 and 4 produced in the reference run.) Rather, the Waena units act as an enabler to allow the system to operate more efficiently. These units are consistently used to provide spinning reserve, and as such are dispatched at minimum output levels when system reserve is needed. The Waena units provide about 41 GWh (the reserve capacity provided in each hour, summed over the year) in spinning reserve, as opposed to the 23 GWh provided by M14, 15, and 16, and 16 GWh provided by M17, 18, and 19.

In this scenario the system is able to dispatch almost 20 GWh more of wind generation than in the reference run, resulting in overall wind curtailment of 10.1%. This additional wind cost about $2.8 million above the reference run wind cost. Despite the increased cost of Waena fuel, greater system operation efficiencies save about $5 million in diesel generation cost. This yields an overall savings of roughly $2.2 million on an annual basis.

25-MW/175-MWh BESS

The system setup in this scenario resulted in an operating cost reduction of $10.1 million for 2015, the greatest reduction in total generation costs relative to the reference case. This number results from a reduction in diesel fuel and variable operation and maintenance (VO&M) costs for diesel generation units. Wind curtailment for this setup is also lower than in any other scenario, at 2.3% with 300 GWh of wind accepted onto the system.

This large reduction in system costs and the increase in wind accepted onto the system result from the ability of the large 25-MW/175-MWh battery to be able to provide both arbitrage and reserve service. Considering a daily average over the year, the system provides 82 MWh of generation and 109 MWh of charging load, while also providing 381 MWh of reserve service. As a result, excess wind at nighttime can be stored for release during the day, reducing diesel generation and concurrently providing reserve, reducing the need for additional diesel units to be online while allowing the combined cycle units to operate at more efficient levels. Additionally, the shutdown of the KPP K3 and K4 units facilitates this savings as wind generation and combined cycle unit operation replace this expensive and inefficient diesel generation both during the nighttime and during peak load periods. Approximately 140 GWh of K3 and K4 generation is replaced by 42 GWh of additional wind generation and 82 GWh of combined cycle generation.

This scenario is the best-performing scenario in terms of the overall reduction in generation cost, wind curtailment, and value to the island while maintaining system capacity. However, taking economic costs into consideration presents a different picture. Estimated installed system cost for the battery system is $87.5 million, resulting in an 8.7-year payback time frame and an NPV of $29.6 million over a 30-year time frame.

25-MW/1200-MWh Cryogen Storage

The system under this scenario resulted in the fourth-greatest reduction in annual production cost relative to the reference case at $5.2 million. This number results from a reduction in diesel generation costs, which is a combination of fuel and VO&M costs for operating the system's diesel units. Wind curtailment is the second lowest, at 2.5% with 299 GWh of wind accepted onto the system.

This reduction in production cost and the increase in wind accepted onto the system result from the ability of the large 25-MW/1200-MWh cryogen energy storage system, similar to the case of the battery in the previous scenario, to be able to provide both arbitrage and reserve service. Considering a daily average over the year, the system provides 95 MWh of generation and 190 MWh of load, while also providing 190 MWh of reserve service. This indicates that excess wind at nighttime is being stored for release during the day, reducing diesel generation and concurrently providing reserve service, further reducing the need for diesel units to be online. In this case, like before, the lack of a K3 and K4 must-run requirement results in a significant efficiency improvement of the system with an increase of 43 GWh of wind and 100 GWh of combined cycle generation.

Despite the greater capacity as compared to the 25-MW/175-MWh BESS scenario, however, the cryogen unit has significantly lower round-trip efficiency at 50% versus 75% for the sodium sulfur battery system, and thus provides only about 50% of the relative savings in operating costs.

That said, system costs strengthen the business case for this scenario. The estimated installed capital cost for the cryogen unit is $31.25 million, resulting in a 6-year payback time frame and an NPV of $40.3 million over a 30-year time frame. This scenario performs best in terms of NPV and relatively well in terms of simple payback. However, there is a significant initial investment required. It is also important to remember that even though the individual components employ proven technology, the cryogenic storage system as a whole is currently in demonstration. There is uncertainty in capital and operational costs, and the estimates used here may not employ a sufficient uplift for the large storage volume specified.

30-MW Waena + 5-MW/35-MWh BESS

This scenario resulted in the second-greatest reduction in generation costs at $5.7 million. Wind curtailment for this setup ranks third, at 6.9% with 286 GWh of wind accepted onto the system.

This reduction in system costs and the increase in wind accepted onto the system result from the combination of the 5-MW/35-MWh storage system and the 30-MW quick-start biodiesel generation facility providing both energy and reserve services. Despite nearly the doubled cost of biodiesel relative to conventional diesel, the combination of the battery system providing generation, load, and reserve service and the quick-start generation providing generation and reserve service at peak times leads to system savings that are higher than in the cryogen scenario, yet still about half that of the large battery scenario.

Considering a daily average over the year, the battery system provides 18 MWh of generation and 25 MWh of load, while also providing 94 MWh of reserve service. The quick-start unit provides 48 MWh of generation on average and 77 MWh of reserve service. The combination of both of these systems reduces the energy demand from other diesel generation units, and reduces their need to be online to provide reserve service, especially during the nighttime. Additionally, the removal of the KPP units here increases wind generation by 29 GWh and combined cycle generation by 64 GWh.

Considering system costs, Scenario 8 does not present the best business case. The estimated installed system cost for the two units are $47.5 million, resulting in an 8.3-year payback time frame and an NPV of $31 million over a 30-year time frame.

35-MW Waena + Transmission Line

This scenario presents a reduction in generation costs of $3.1 million. Wind curtailment for this setup ranks sixth, at 10.0% with 276 GWh of wind accepted onto the system.

This reduction in system costs and the increase in wind accepted onto the system relative to the reference system are due largely to the provision of reserve service from the 35-MW quick-start biodiesel generation facility, despite biodiesel being double the cost of conventional diesel. It provides reserve service throughout the day, dropping off at night, and is the regulation provider of choice. It has a low minimum output, and its flexibility aids in reducing curtailment, as indicated by the 3,000 unit starts over the year for its seven generation units. Again, as in the above scenario, KPP units are unavailable, reducing KPP generation by 148 GWh relative to the reference case. Combined cycle output increases by 64 GWh, and 19 GWh of additional wind is accepted.

This scenario, however, has a limited business case. The reduction in value relative to the previous scenario is from the increased use of the biodiesel unit as well as increased use of other diesel generation to provide reserve service, whereas the previous scenario utilizes its battery system. The estimated installed system cost for the quick-start generation units and an additional transmission line connecting the 23-kV and 69-kV sections of the island’s grid are $40 million. This results in a 13-year payback and an NPV of about $3 million over a 30-year time frame.

CONCLUSIONS

This bulk power system study uses hourly production cost modeling to understand how the MECO system might operate in 2015. Wind and load data were supplied by GE, and are the same as those being used for the ongoing SIS. MECO and HECO provided data on the planned makeup of the generation fleet for 2015, and on the generator characteristics. In addition, the model used for this study was calibrated against the HECO's P-Month generation planning model to ensure that it accurately reflects the MECO dispatch order.

Scenarios for this study were developed collaboratively with MECO and HECO. Of the eight scenarios, five of them add an energy storage system to the reference case, two add a reciprocating engine plant running on biodiesel, and one scenario combines an energy storage system with a new biodiesel plant.

All of the scenarios maintain or increase the level of installed capacity on the Maui grid. The installed capacity is held constant by changing the use of the KPP units. The must-run status of the KPP units is currently necessary to maintain active and reactive power on the low-voltage side of the Maui electric grid in the event of a transmission interconnect contingency. Designating KPP as must-run, however, results in an increase in wind curtailment. Any scenario reducing KPP generation must allow for sufficient active and reactive power on the low-voltage side of the network in the event of a contingency.

All of the scenarios result in annual savings compared to the reference run. Most of the savings achieved in these scenarios are not from replacing constant-cost diesel-fired generation with wind generation. Instead, the savings are achieved by the more efficient operation of the conventional units of the system. Using additional storage for spinning reserve enables the system to decrease the amount of spinning reserve provided by single-cycle units. This decreases the amount of generation from these units, which are often operated at their least efficient point (at minimum load). At the same time, the amount of spinning reserve from the efficient combined-cycle units also decreases, allowing these units to operate at higher, more efficient levels.

In the MECO system of 2015, the ability to do time-of-day shifting facilitates the dispatch of more wind. However, adding additional energy storage volume to a storage device does not appear to significantly increase the efficiency of conventional unit operations. The difference in annual savings between the scenarios that add a 10-MW BESS can be almost entirely attributable to greater wind dispatch and avoided diesel consumption; the savings from conventional generation system efficiencies increase only slightly with increased energy storage volume.

If one were interested in the project that would provide the greatest return for the least risk (in terms of amount of investment), the 10-MW/15-MWh BESS would likely be that project. If one were interested in the project with the highest NPV, as well as with significant upside should the round-trip efficiency be increased above 50%, then the 25-MW/1200-MWh cryogen storage facility is worth investigating. If one were interested in the highest overall percentage of renewable generation, then this would be the 30-MW Waena plant plus 5-MW/35-MWh BESS project, or the 35-MW Waena plant project.

The Waena biodiesel plants, if not paired with a storage system, do not rank highly in terms of project NPV. However, one must consider that such a plant allows the system to replace about 150 GWh per year of residual fuel-fired generation with cleaner forms of generation at a net reduction in system operational cost – even though it is required to burn biodiesel, which is almost three times more expensive than residual fuel.

Some important caveats are in order. First, the primary focus of this study was to calculate the annual system savings (compared to the reference case) of each scenario. In order to calculate the financial value of each project, the assumption is made that the annual savings calculated is a reasonable estimate of annual savings going forward. Annual savings going forward can differ from those calculated for 2015 for the following reasons: (1) wind and solar generation amounts or variability could differ from the study year; (2) changes may be made to the conventional generation fleet over time; and (3) fuel prices may vary from those assumed for 2015.

Because they are based on the cost savings calculated for a single year, the study team does not believe that NPV calculations in this report are highly accurate estimates of project value, and would therefore advise that an investment decision should not be made on the basis of these numbers alone. Instead, the study team believes that the NPV calculations here are an indication of how large a project's benefit may be, and are a useful addition to the simple payback calculation.

Second, this study used the spinning reserves requirement that has been developed in the ongoing SIS. The specification of spinning reserves is an important factor in how the system is dispatched, and will have an impact on the cost savings yielded by storage projects and new generator additions. As of the date of release of this report, the new reserves specification had not yet been thoroughly vetted, and a decision had not been made as to whether it would be adopted – or whether modifications to the specification would be required. In addition, adopting a new reserves specification would likely require MECO to secure agreement from the independent power producers (IPPs), as the wind farm PPAs contain provisions tied to the existing MECO reserves practice.

While not a focus of this report, the study team did analyze the same storage scenarios using the existing reserves specification. The results of runs were broadly similar, though they show somewhat lower savings as compared to the reference run. (The results of runs using the existing reserves specifications, as well as using different diesel fuel prices, can be found in Appendix F.) At the same time, if MECO decides to maintain the existing reserves specification, it would be prudent to do a detailed review of the results using that specification.

Third, the estimated system cost used here represents an estimation of what such a system might cost in the continental United States in 2015. This does not include any additional costs for transporting and installing the system in Hawaii.

REFERENCES

[1] G. Energy, Report to: HECO/MECO for MECO Wind Integration Study- Final Report [CONFIDENTIAL], Schenectady, NY, June 2010, 2010.

[2] NREL, *Hawaii Solar Integration Study Update*, ed: Hawaii Clean Energy Initiative, 2011.

[3] A. Akhil, [DRAFT] DOE/EPRI 2012 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association, Sandia National Laboratories, Albuquerque, NM, November 2012, 2012.

APPENDIX A: MODEL VERIFICATION

The Maui Electric Company (MECO) system model modeled here was compared to the output produced by MECO's modeling utilizing the production cost model *P-Month*. An effort was made to ensure that the input parameters for the *PLEXOS* comparison run were the same as those utilized for MECO's modeling. Specifically, this effort involved:

- A modification of the system's commitment order to match that in place within the *P-Month* model to reflect system operations.
- The utilization of the same yearly load, wind and photovoltaic generation profiles as used within the *P-Month* model.
- A removal of the Hawaiian Commercial and Sugar Company biomass contract.
- Minimum operating constraints for the K1, K2, K3, and K4 units.
- Unit maintenance profile as used in the *P-Month* model.
- Start fuel parameters as used in the *P-Month* model.
- Renewable energy generation units as those modeled in the *P-Month* model: photovoltaic, small hydro, and wave generators and their annual profiles.

The primary means by which the *PLEXOS* model was verified was a comparison of its outputs to those of the *P-Month* model for generation profiles for all units, for the first three days of operation during the year.

It would be unreasonable to expect that the outputs of both models would be exactly identical considering that the models are different and thus formulate the optimization problem differently. The solvers utilized by each model are also different. Last, the means by which the reserve problem is solved, being dependent on the renewable energy dispatch, is different. The *PLEXOS* internally iterates renewables dispatch and reserve requirements while *P-Month* requires iteration external to the model.

Despite the issues identified above, the *PLEXOS* output closely matches the *P-Month* output. The generation quantities are in the expected range, and the dispatch profile is identical. This indicates that the *PLEXOS* model is an accurate representation of MECO system operations. The outputs of the *P-Month* model are verified by MECO's generation planning group on historical operational data, leading to a degree of confidence that the model projects realistic system operations.

APPENDIX B: STORAGE MODELING

PLEXOS contains a pumped hydro model that allows the user to simulate energy storage resources. Using the energy mode of the pumped hydro mode within *PLEXOS*, it is possible to set maximum and minimum energy levels, round-trip efficiency, generation and pump capacities, and associated costs to model an energy storage system. Additional flexibility is possible with the software's in-built constraint and condition capabilities allowing the user to set operating parameters and limits.

Depending on the scenario, the various storage systems provide energy and reserve service, only reserve service, and regulation down service. When providing multiple services, the model conducts co-optimization over the model horizon (1 day in this study), to determine the least cost dispatch of the entire system.

As discussed previously, a production cost model is unable to dispatch resources to model actual reserve dispatch. Instead, it holds these reserves in a "regulation raise (and lower) reserve" category where they cannot contribute to energy or other reserve services, and thus it is assumed they will be available to meet reserve requirements. However, in an energy storage system, even with the assumption that is made here of an energy net zero in serving reserve services over a long time frame, an hour in this case, there are losses from the inefficiencies of charging and discharging. To address this energy loss, the energy storage systems have an auxiliary load. This continuous auxiliary load for each storage system is calculated as:

$$aux\ load = (1 - AC\ roundtrip\ efficiency) * (25\%) * (average\ regulation\ raise\ provision)$$

where *AC round-trip efficiency* is the storage system's round-trip AC-to-AC efficiency; *25%* is an assumption of the amount of actual reserve demanded by the system relative to the amount provisioned*;* and the *average provision* is the averaged reserve provision on the storage system over the year. This is determined by an identical simulation of the system without auxiliary load enforced.

Table B-1 below specifies the input parameters for the different energy storage systems. These parameters are based on the specification available in Sandia National Laboratories' *DOE/EPRI Energy Storage Handbook* [3].

Table B-1. Input Parameters for the Storage Systems Modeled in Each Scenario.

	Type	Power	Min P	Energy	VO&M	Aux Base	AC-AC Eff	FO&M
		MW	MW	hrs.	$/MWh	MW	%	$/kW/year
KWP2 Battery	Adv. LA	10	-	2	0.40	0.25	90	9
10 MW/15 MWh battery	Li-Ion	10	-	1.5	0.40	0.23	90	9
10 MW/70 MWh battery	NaS	10	-	7	0.76	0.48	75	5
25 MW/175 MWh battery	NaS	25	-	7	0.76	0.99	75	5
25 MW/1200 MWh cryogen	Cryogen	25	8	48	0.35	0.99	50	5
5 MW/35 MWh battery	NaS	5	-	7	0.76	0.24	75	5

Power is maximum capacity for generation and charging; *Min P* is the minimum output of the storage system, a non-entry indicates no minimum; *Energy* is amount of time the maximum capacity can be generated; *VO&M* is variable operation and maintenance costs; *Aux Base* is the auxiliary load charged to each system to provide reserves; *AC-AC eff* is system round-trip AC-AC efficiency; and *FO&M* is the yearly fixed operation and maintenance cost to operate the system.

APPENDIX C: THREE-DAY DISPATCH RESULTS

The following figures illustrate system dispatch of the reference run and each of the scenarios over the first three days of 2015.

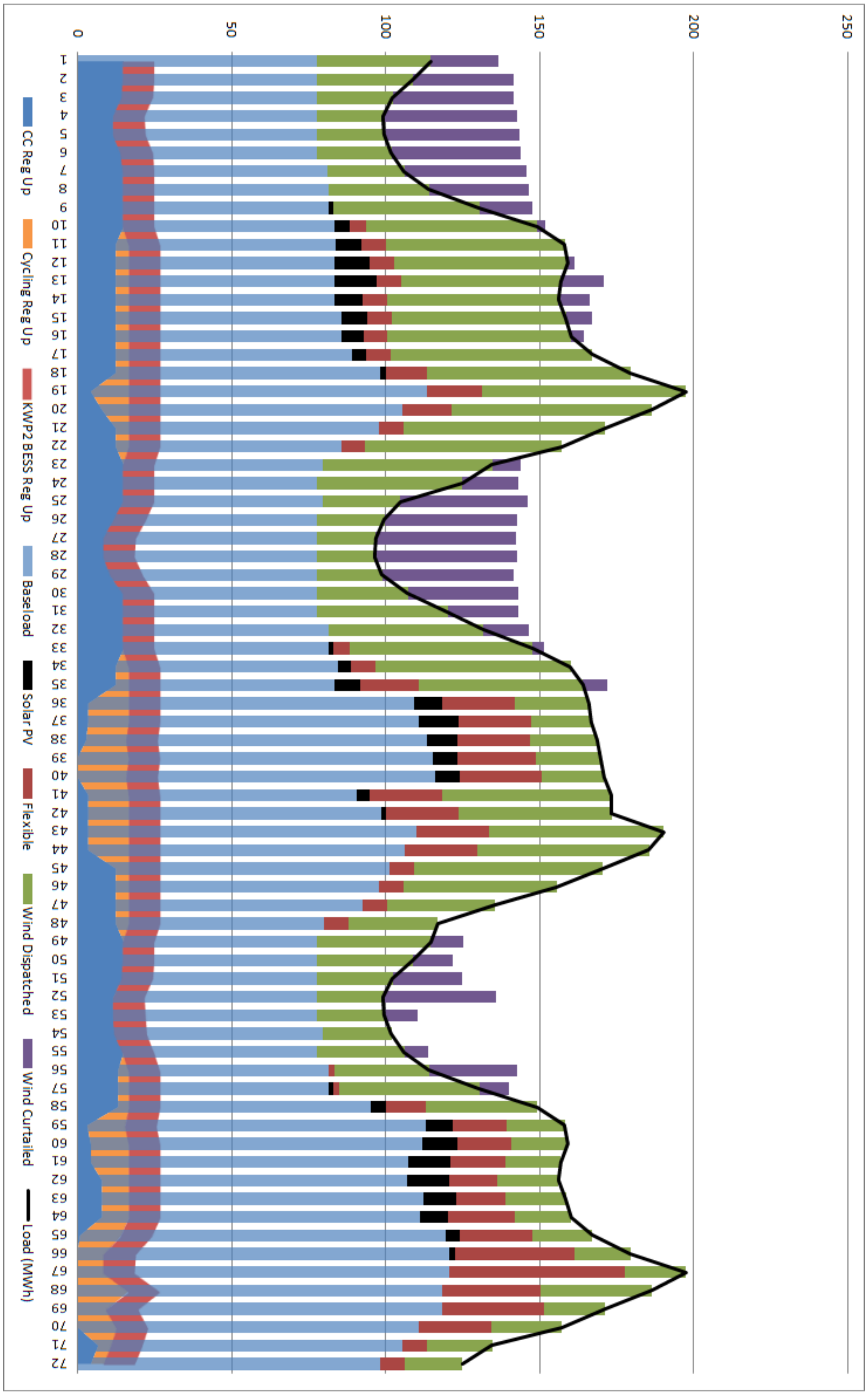
There are two different quantities depicted on these figures – one is dispatch from the various categories of generators, and the other is the amount of spinning reserves (which appears as regulation up, or "reg up," in the legend). The amount of dispatch from each type of generator is shown in solid bars, which are stacked, such that the sum of all of the dispatched resources equals the load. The amount of spinning reserves is shown in a solid contour at the bottom of the figure. These contours are also stacked, such that the sum of all the resources providing spinning reserves equals the total amount provided. These two different quantities – dispatched energy (actually provided) and operating reserves (held in reserve) – are displayed on the same graph, but are not summed together.

For the dispatched energy part of the graph, there are several categories of generators. "Baseload" refers to any plants that are must-run (such as the Kahului units, if they are part of the scenario, and the Hawaiian Commercial and Sugar Company biomass plant) as well as the two combined-cycle blocks at Maalaea. "Solar PV" is for generation from distributed photovoltaic solar, and is displayed just above the baseload category since it cannot be curtailed. The "flexible" category refers to the remainder of the conventional units on the system – M1 through M13, MX1 and MX2, and the Hana units. "Wind Dispatched" indicates the amount of wind that was dispatched, and "Wind Curtailed" indicates the additional wind resource that was available but could not be dispatched. The system load is displayed as a black line.

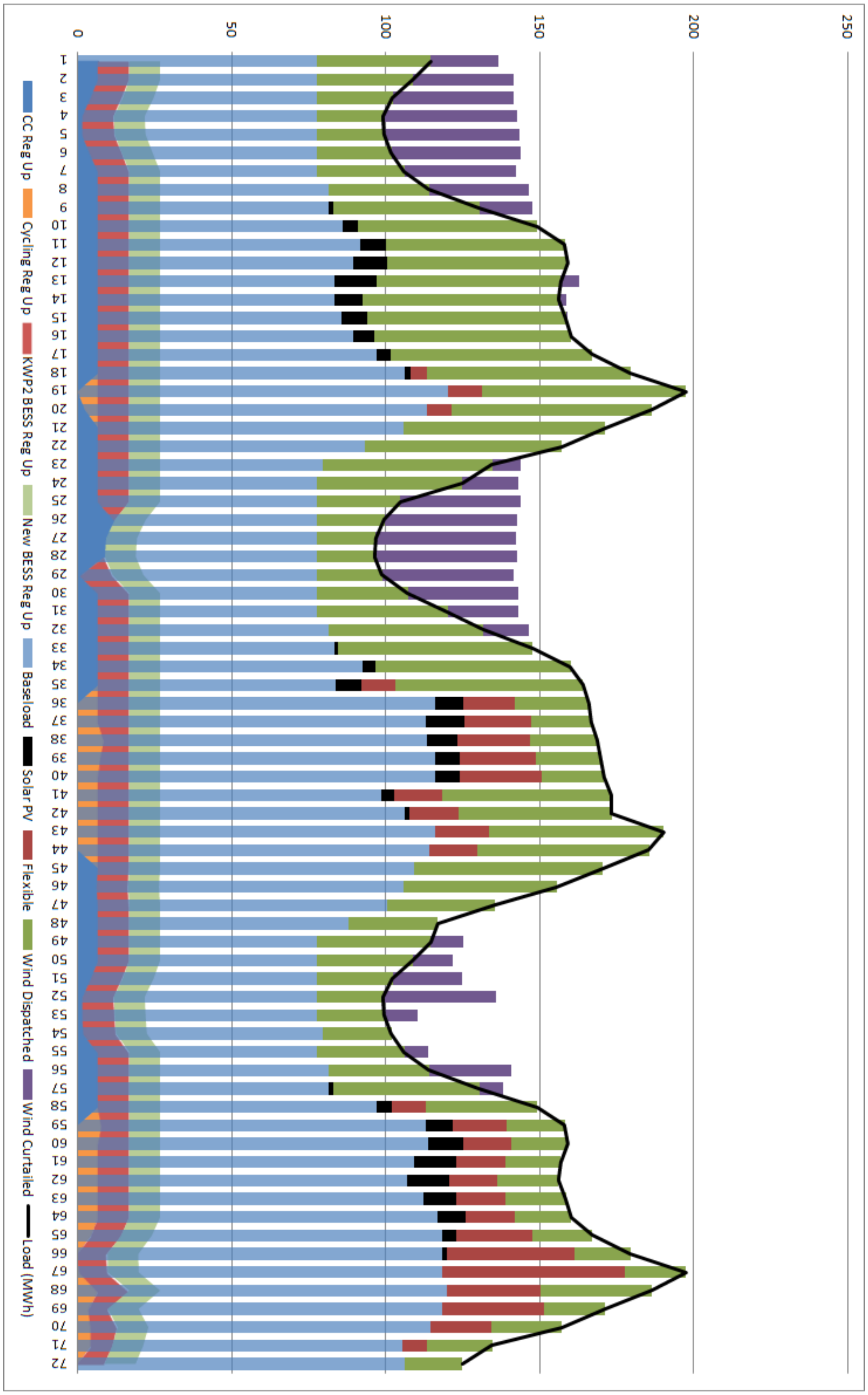
For the reserves part of the graph, "CC Reg Up" refers to the spinning reserve provided by the combined cycle units, "Cycling Reg Up" is for the spinning reserve provided by the cycling units at Maalaea, and "KWP 2 BESS Reg Up" refers to the contribution of the battery system at KWP 2 towards spinning reserves.

Of note on these figures is that when a storage unit charges, it is displayed as a bar that goes below the x-axis. In these cases, the amount of dispatched wind can rise above the load line. This is the case because enough energy needs to be dispatched to satisfy both customer load and the storage system load when the storage unit is charging.

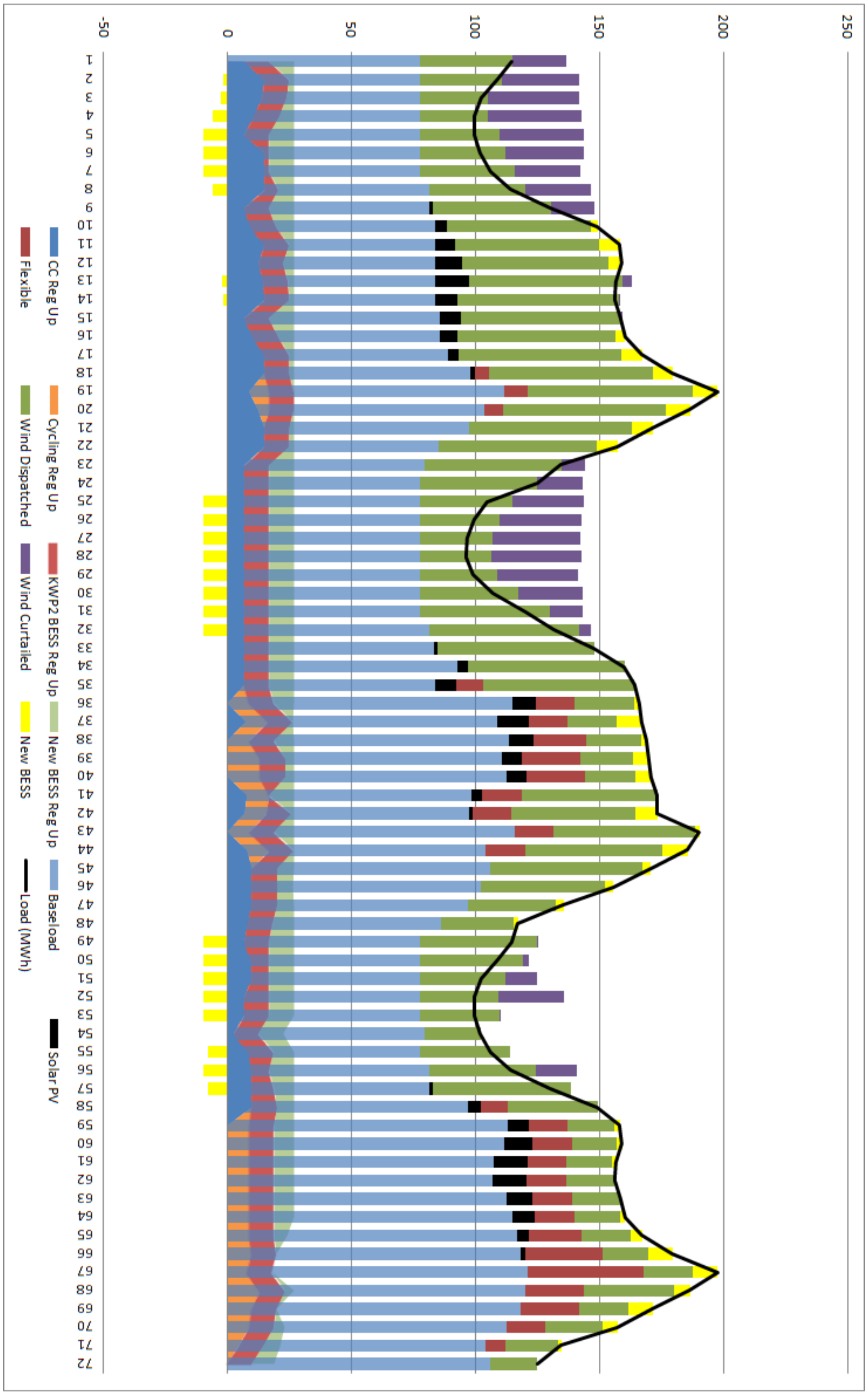
Reference Case



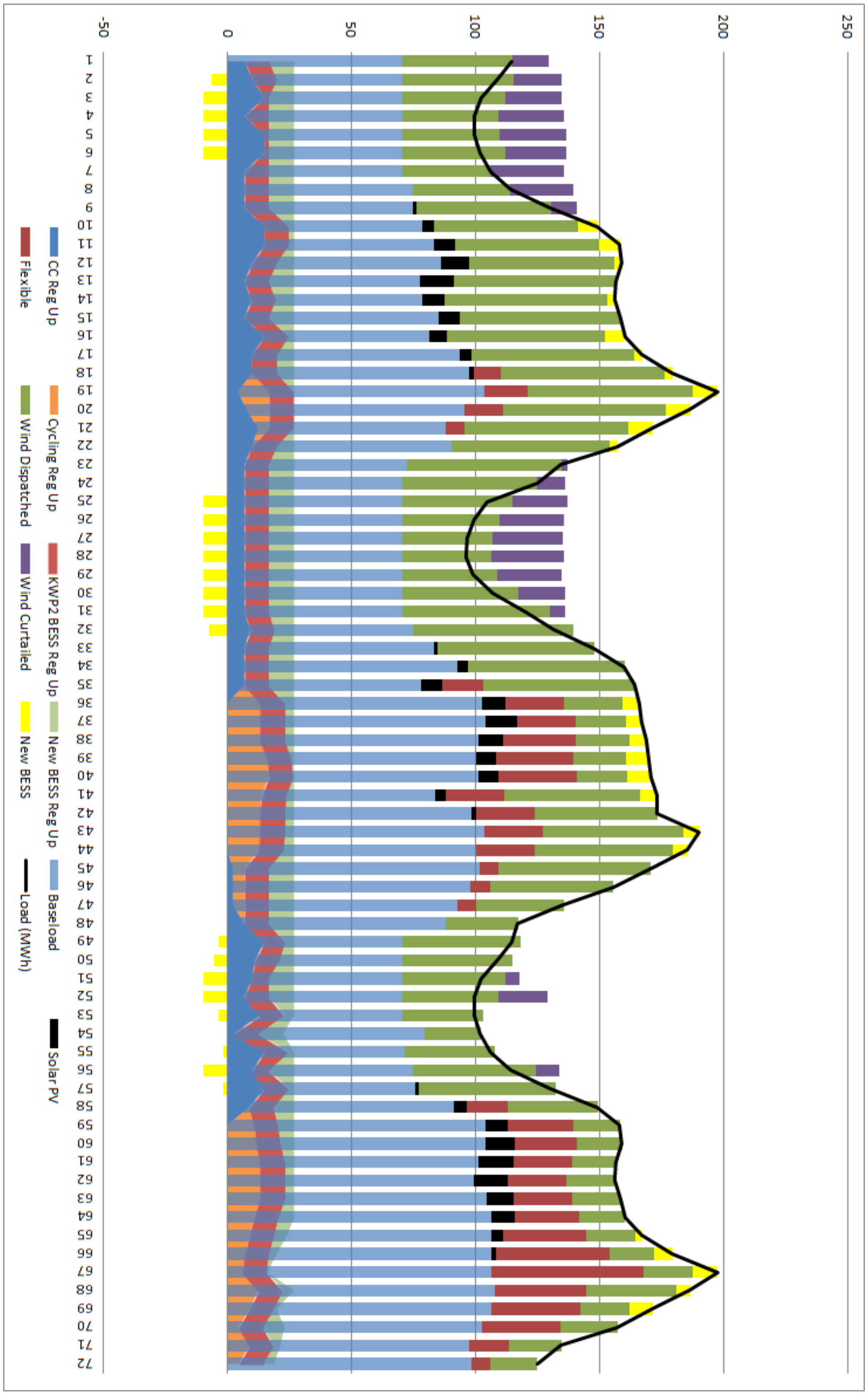
10-MW/15-MWh Battery Scenario



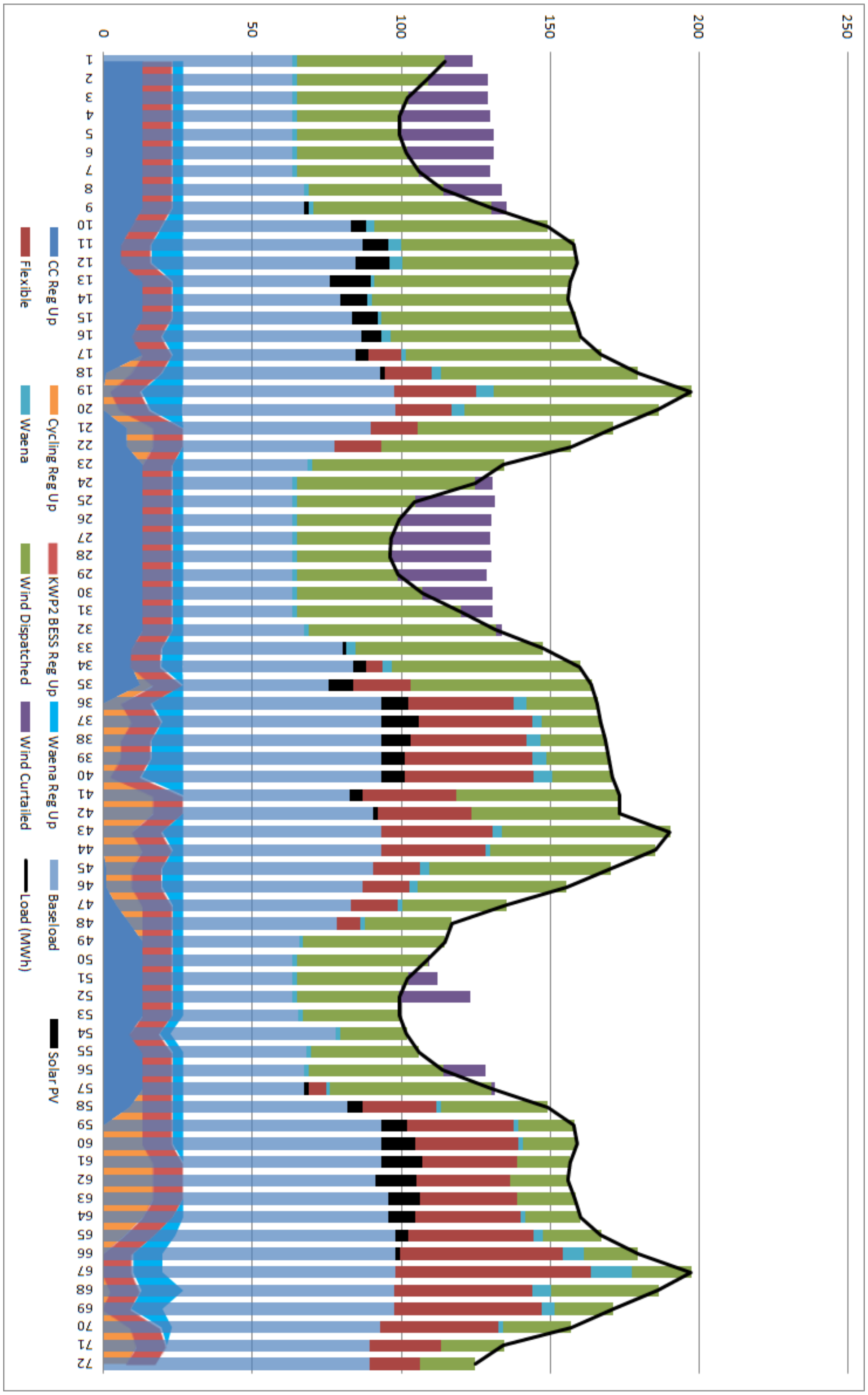
10-MW/70-MWh Battery Scenario



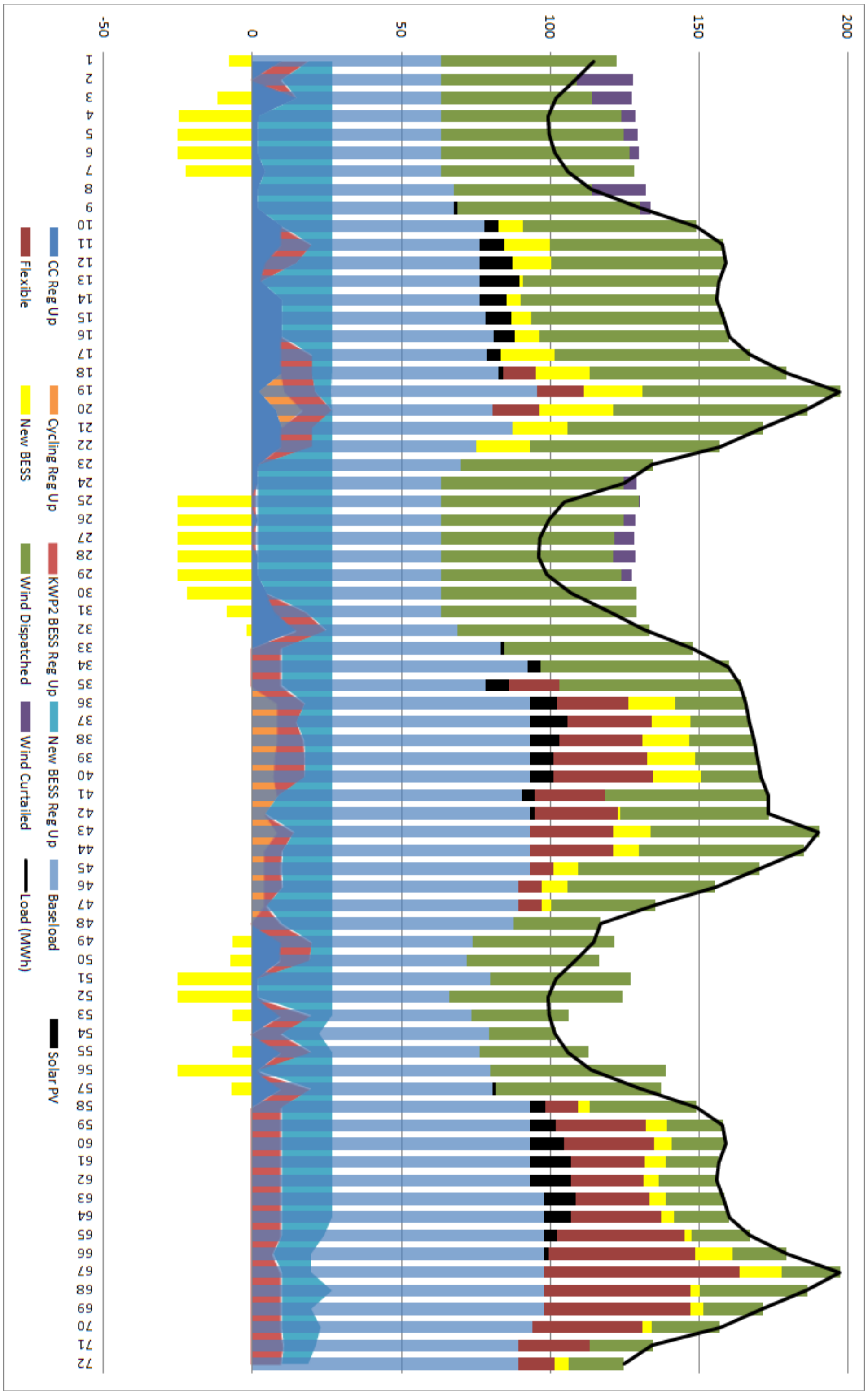
10-MW/70-MWh, No K4 Battery Scenario



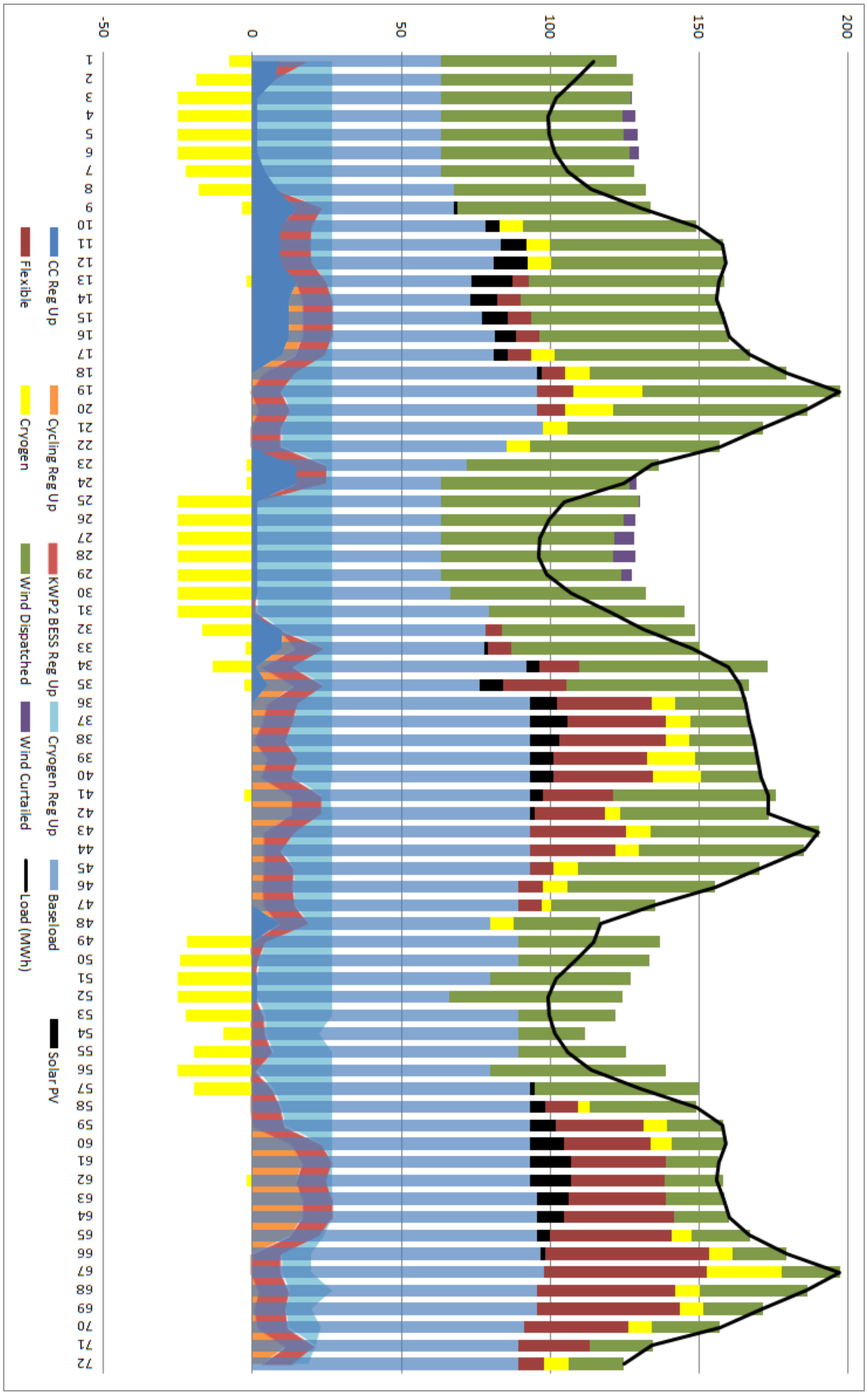
25-MW Waena Biodiesel Generator Scenario



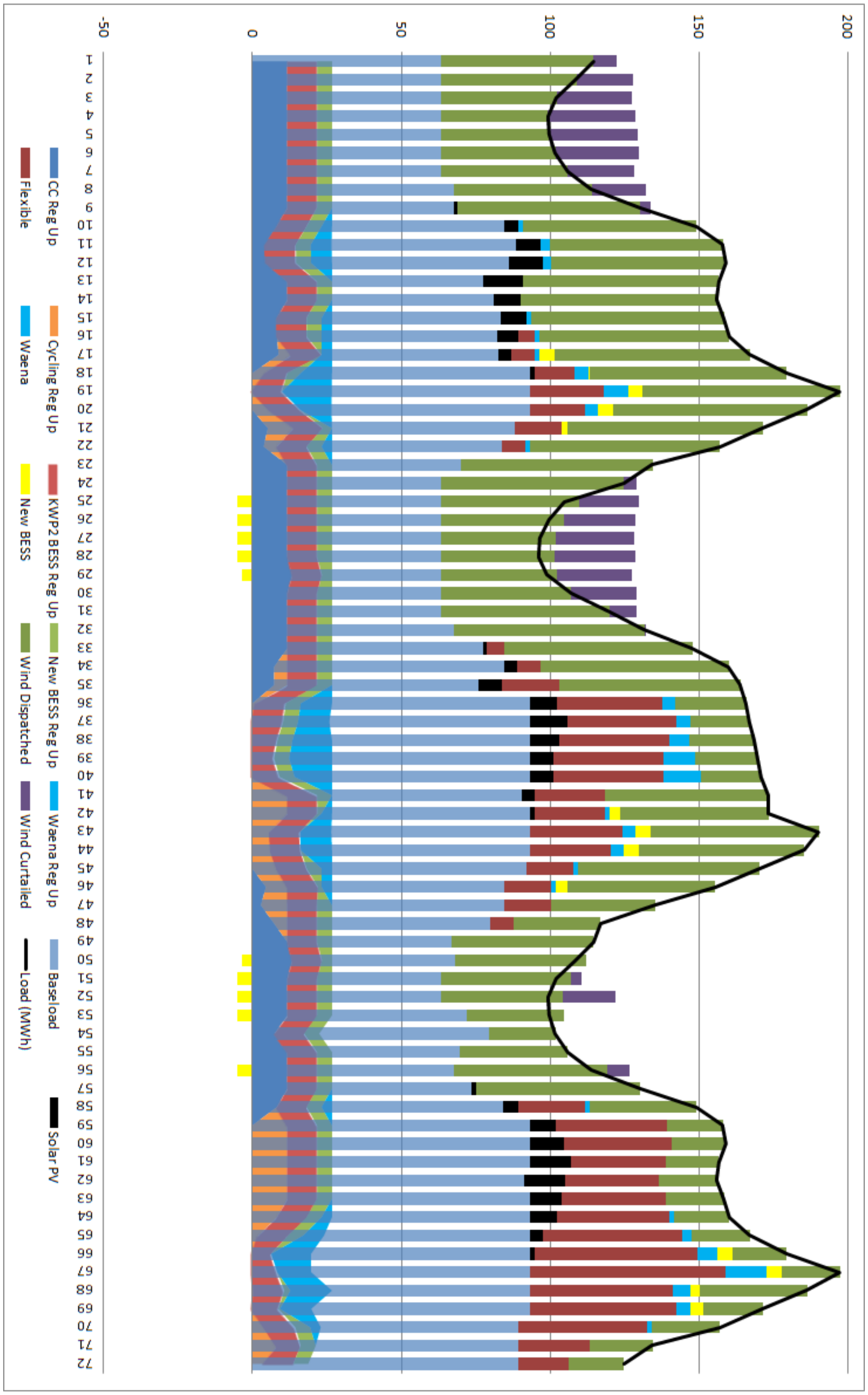
25-MW/175-MWh Battery Scenario



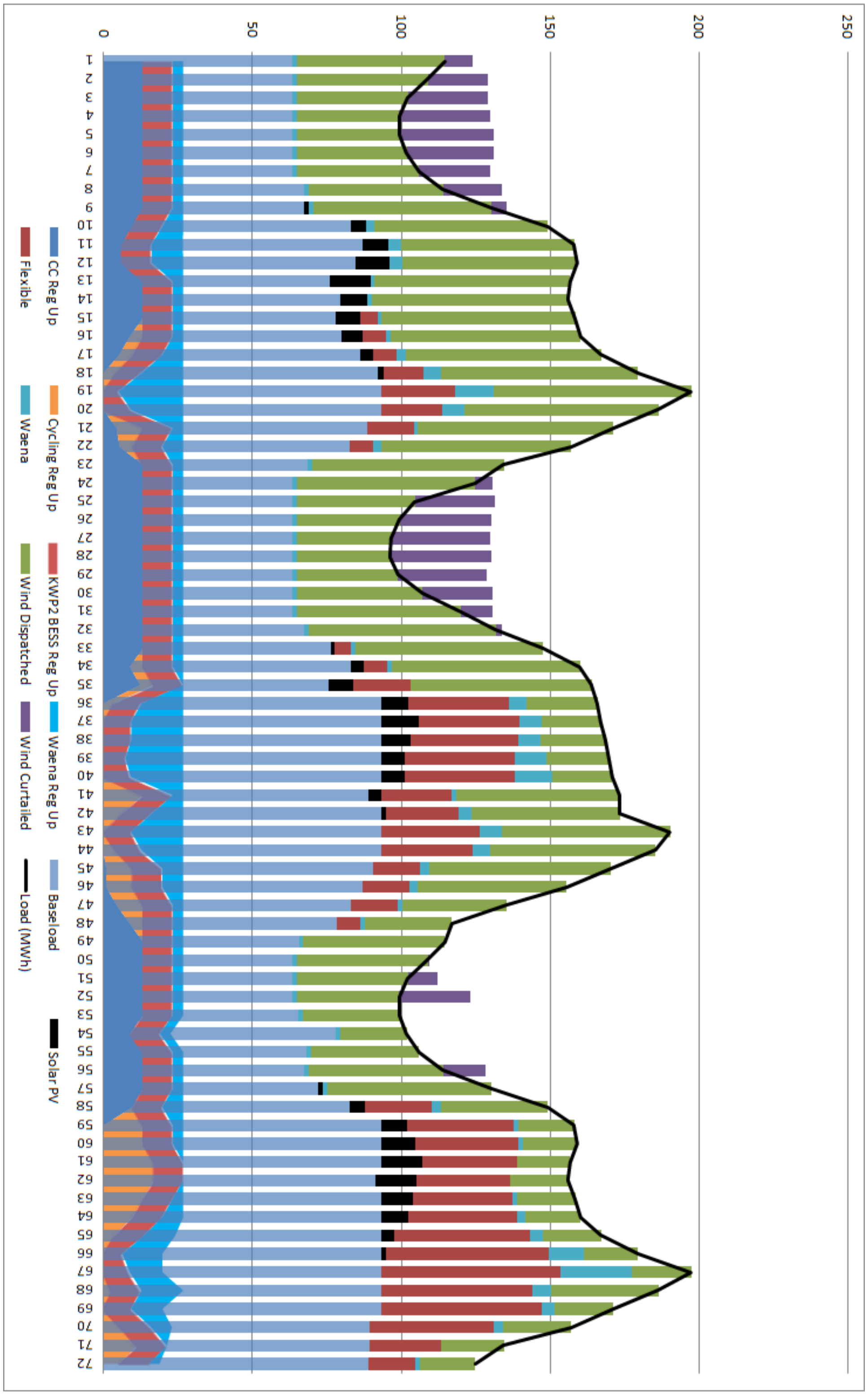
25-MW/1200-MWh Cryogen Storage Scenario



30-MW Waena + 5-MW/35-MWh Battery Scenario



35-MW Waena Generator Plus Transmission Line Scenario



APPENDIX D: LOAD, RESERVE, AND RENEWABLE GENERATION CHARACTERIZATION

Figure D-1 indicates the load, reserve requirement, and renewable generation and availability profiles averaged for each hour over the year for the reference case. The maximum amount of wind curtailment occurs during the early morning and the late night, while nearly all of the daytime (10 a.m. to 6 p.m.) generation is accepted on to the grid.

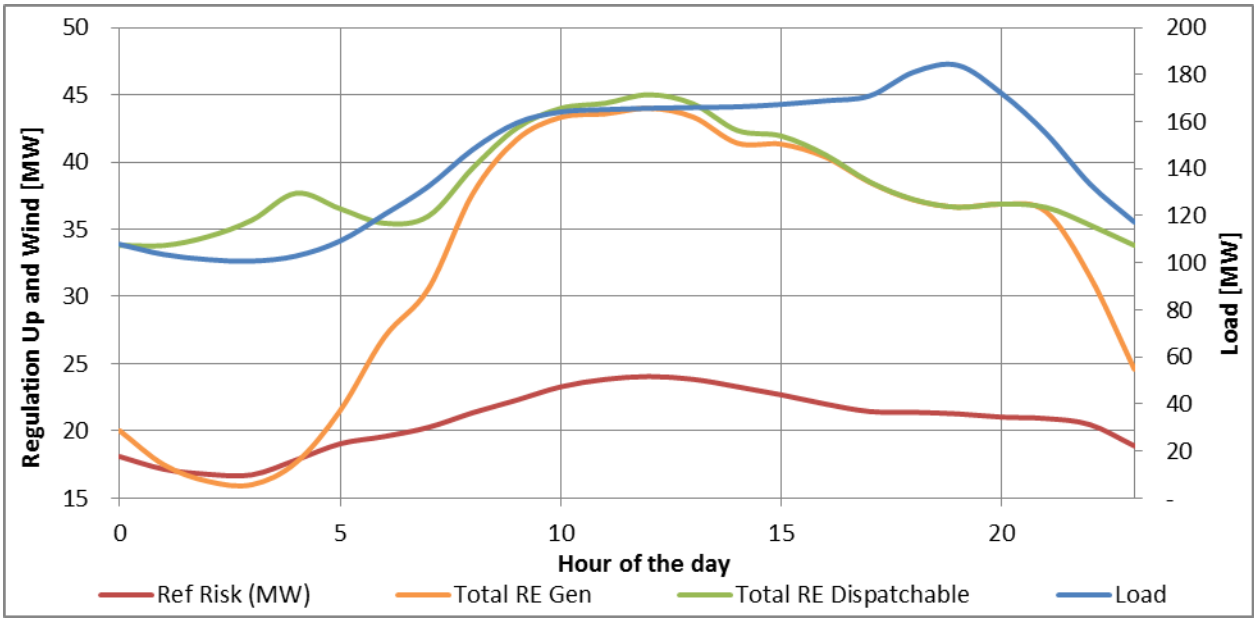


Figure D-1. Daily hourly average load, reserve requirement and renewable generation and resource profiles over the year for the reference run.[15]

[15] *Ref Risk* is the regulation up requirement; *RE Generation* is the total renewable energy generation; *Total RE Dispatchable* is the total dispatchable renewable energy generation; and *Load* is total system load.

Figure D-2 provides the daily hourly average reserve profile for the reference run and the evaluated scenarios. During the day, past 7 a.m. the reserve requirement follows an identical path to a maximum requirement of 24 MW on average for each scenario around 12 p.m., before dropping off through the rest of the day. The real difference in reserve requirement between the scenarios is in the early mornings between midnight and 7 a.m., where all scenarios have an increased requirement over the reference run.

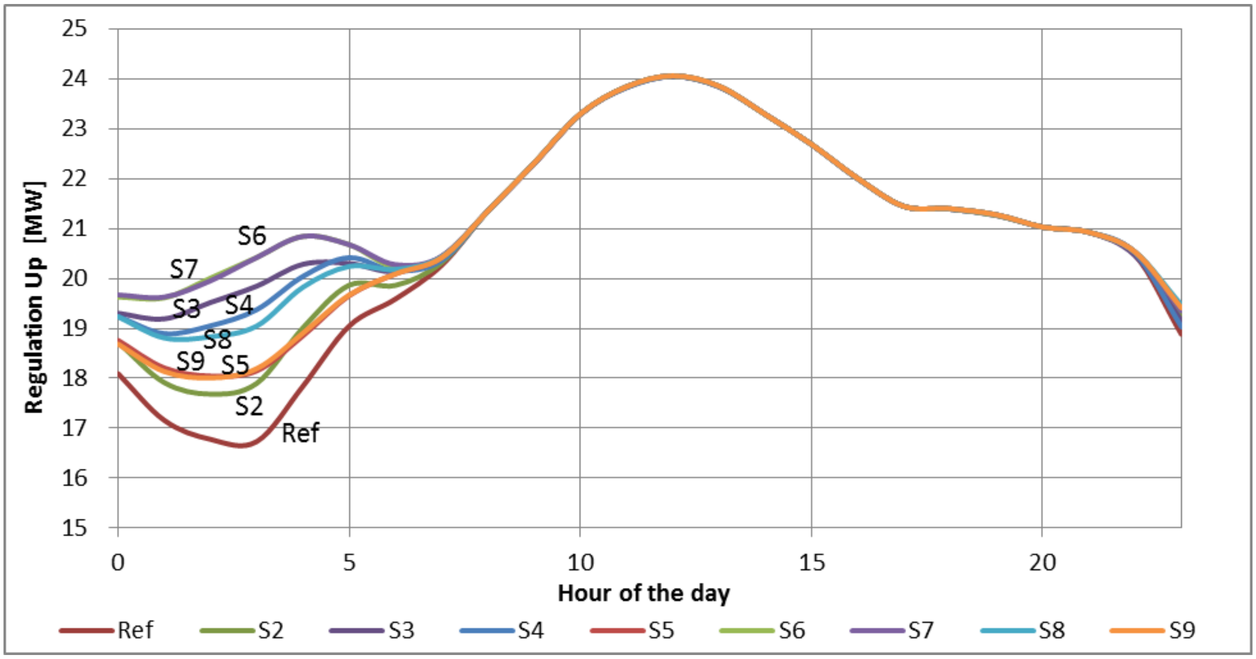


Figure D-2. Daily hourly average reserve requirement profile over the year for each evaluated scenario.[16]

[16] Cross listing of scenarios and scenario numbers for graphs.

#	Scenario
S2	10-MW/15-MWh battery
S3	10-MW/70-MWh battery
S4	10-MW/70-MWh battery, no K4
S5	25-MW Waena
S6	25-MW/175-MWh battery
S7	25-MW/1200-MWh cryogen
S8	30-MW Waena + 5-MW/35-MWh battery
S9	35-MW Waena + Transmission Line

Figure D-3 shows the daily average hourly wind generation profile for the reference run and the evaluated scenarios, along with the available wind resource. It is evident that nearly all of the wind curtailment occurs during the late night and early hours of the morning from 11 p.m. through 9 a.m.. During the day, wind generation is very close to the available resource for all of the scenarios. The differences between the effectiveness of the scenarios at addressing wind curtailment are also apparent through where those scenarios that provide mostly reserve services are less effective than those that provide a significant amount of time-shift. Specifically, the batteries of Scenarios 2, 3 , 4, and 8 either provide no energy or only a limited amount, and thus are unable to make as much of an impact on wind curtailment as compared to Scenarios 6 and 7, which have larger storage systems that can shift a significant amount of energy.

Nonetheless, Scenarios 2, 3, 4, and 8 do have a significant impact on curtailment, primarily through the added reserve resource allowing diesel units to be run at lower levels or shut off entirely. This also applies for Scenarios 5 and 9 where the quick-start biodiesel unit can provide reserves allowing slower units to be operated at lower levels or shut off. Scenario 8 has both a battery and a quick-start unit, and thus is more effective than Scenarios 5 and 9.

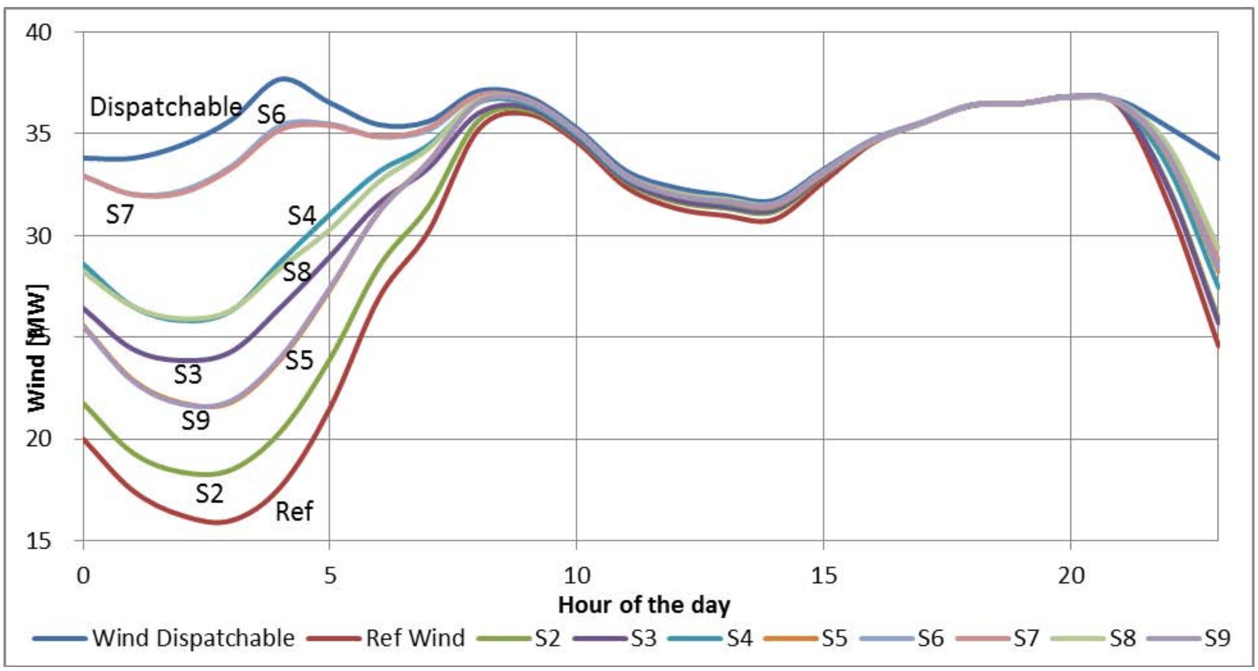


Figure D-3. Daily hourly average wind generation and wind resource profile over the year for each evaluated scenario.[17]

[17] Note: This does not include solar generation.

APPENDIX E: ADDED RESOURCE OPERATIONS

This section contains operational profiles for system additions in place for each of the evaluated scenarios. These profiles provide an indication of the daily operation of these systems. For each system addition, the generation, charging load, reserve provision (regulation up reserve), and storage capacity are averaged for each hour over the year. The operational profiles presented below reflect the demand, wind generation, and reserve requirement profiles presented in Appendix D.

10-MW/15-MWh Battery

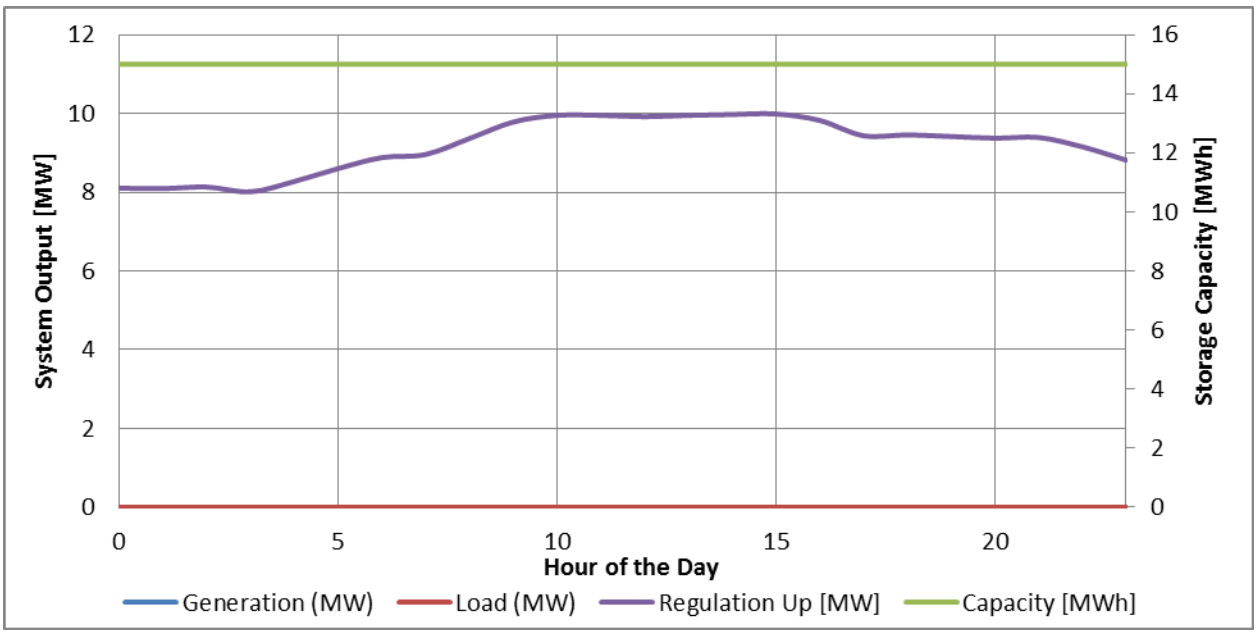


Figure E-1. Profile for the battery system in the 10-MW/15-MWh battery scenario.[18]

[18] Generation is the system output; Load is the charging load; Regulation Up is the regulation up (raise) provision for the system; and Capacity is the storage system's stored/available energy.

10-MW/70-MWh Battery

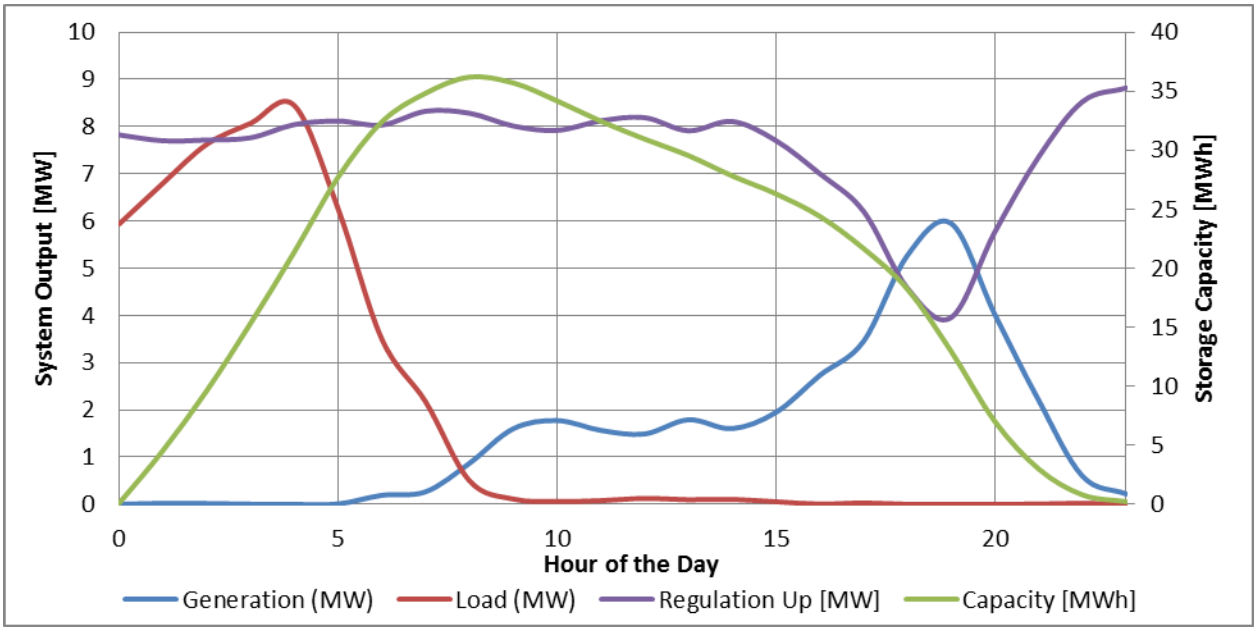


Figure E-2. Profile for the battery system in the 10-MW/70-MWh battery scenario.

10-MW/70-MWh Battery, No K4

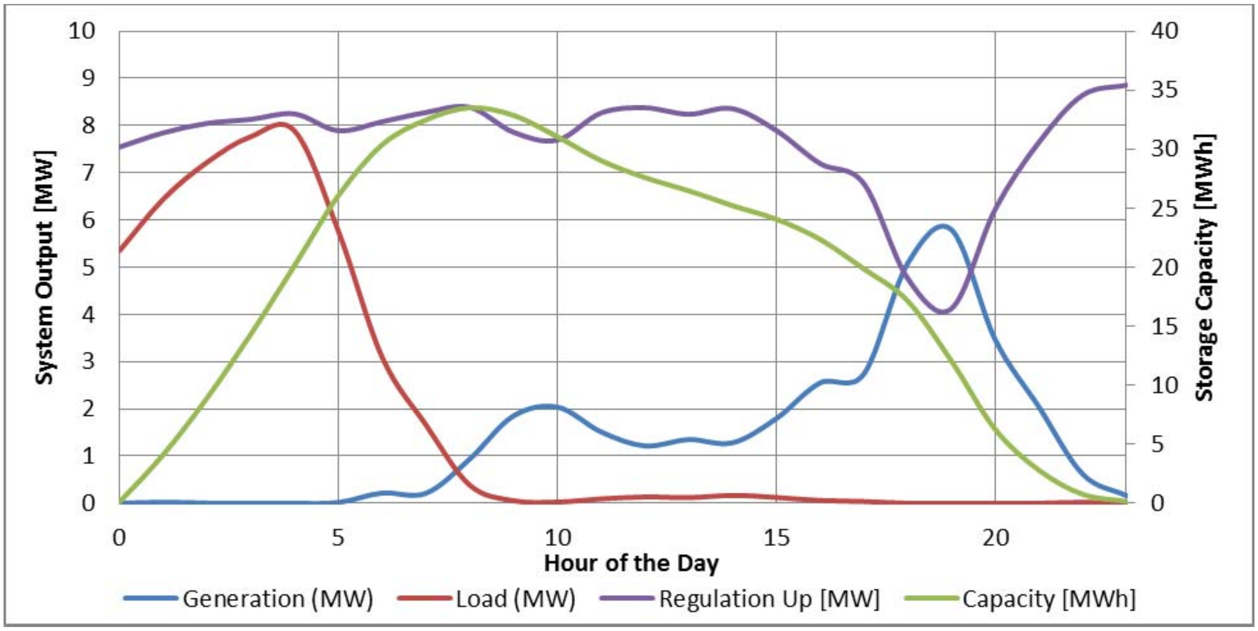


Figure E-3. Profile for the battery system in the 10-MW/70-MWh battery, no K4 scenario.

25-MW Waena

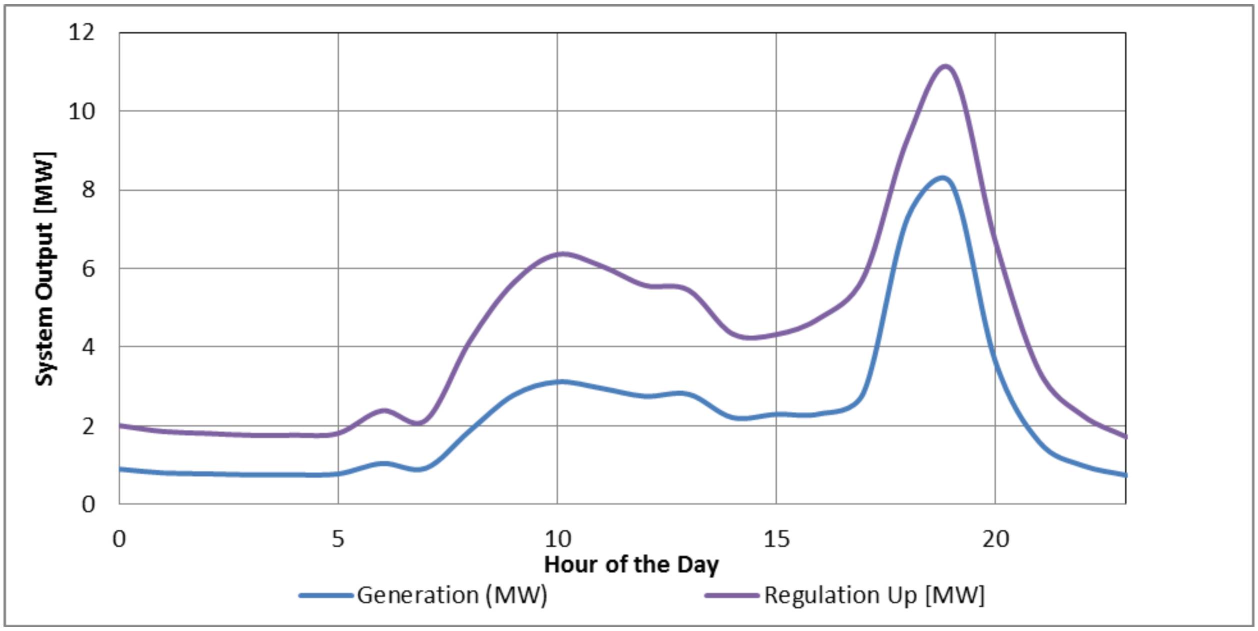


Figure E-4. Profile for the generator in the 25-MW Waena scenario.

25-MW/175-MWh Battery

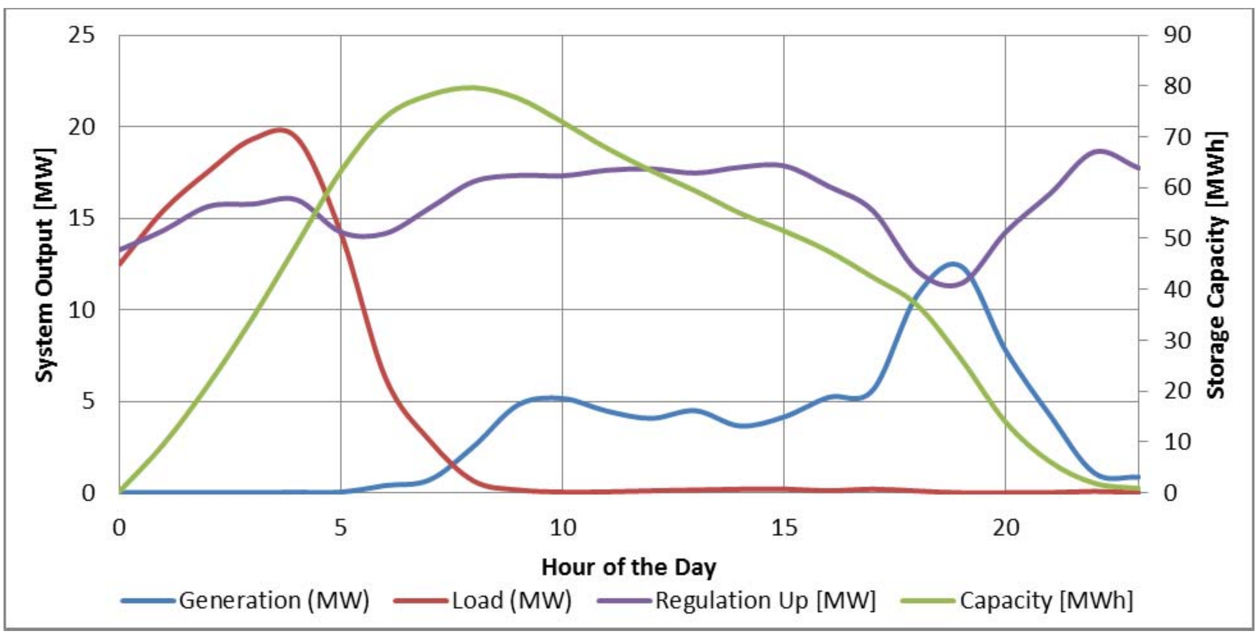


Figure E-5. Profile for the battery system in the 25-MW/175-MWh battery scenario.

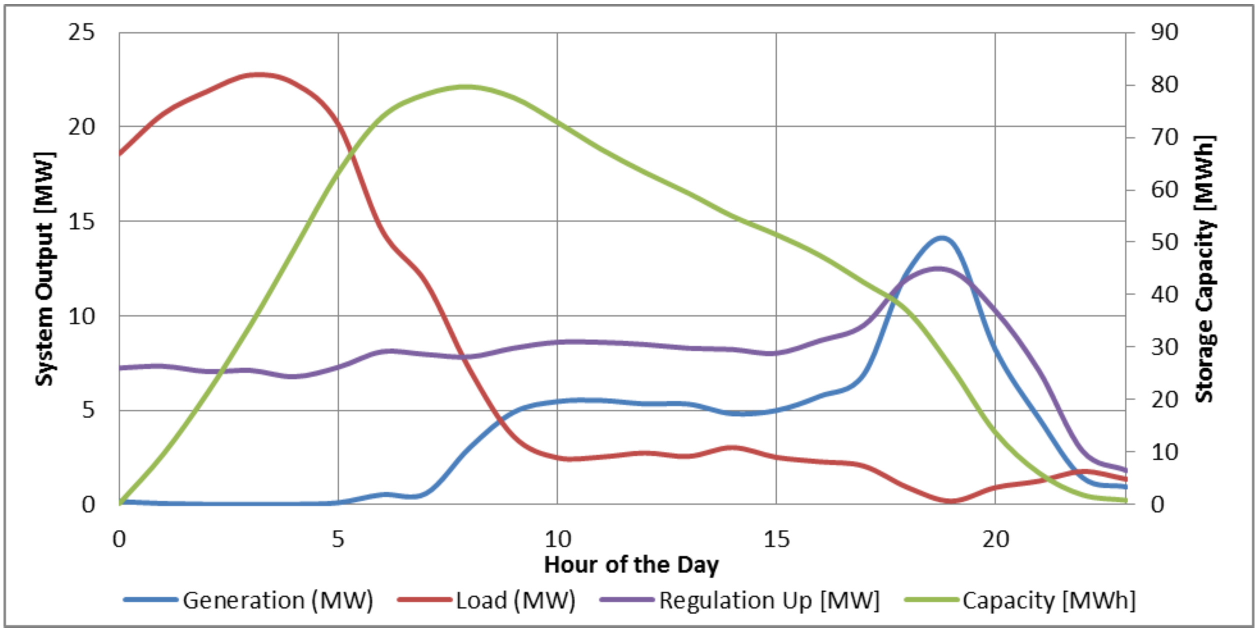


Figure E-6. Profile for the storage system in the 25-MW/1200-MWh cryogen scenario.

30-MW Waena + 5-MW/35-MWh Battery

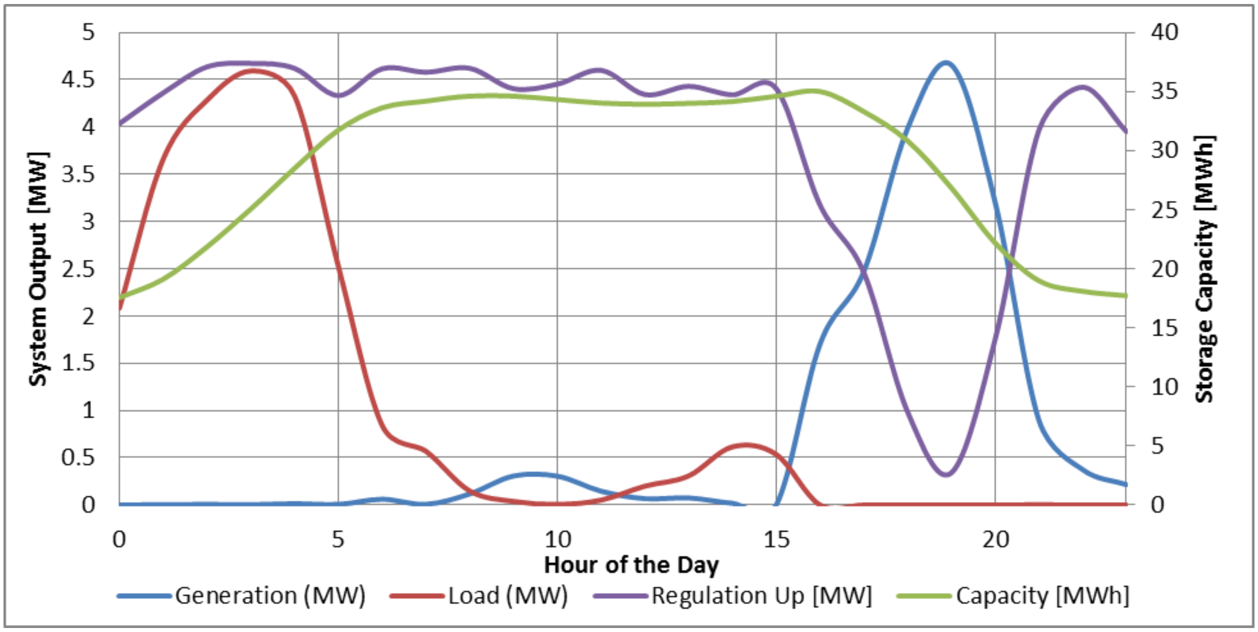


Figure E-7. Profile for the battery system in the 30-MW Waena + 5-MW/35-MWh battery scenario.

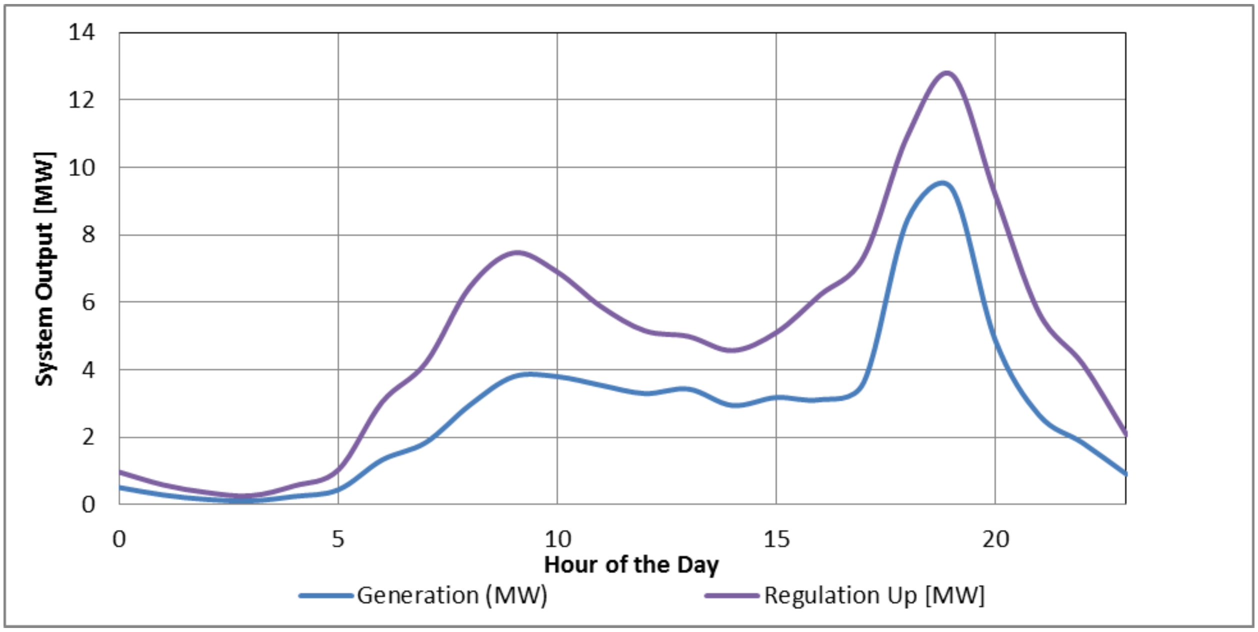


Figure E-8. Profile for the generator in the 30-MW Waena + 5-MW/35-MWh battery.

35-MW Waena + Transmission Line

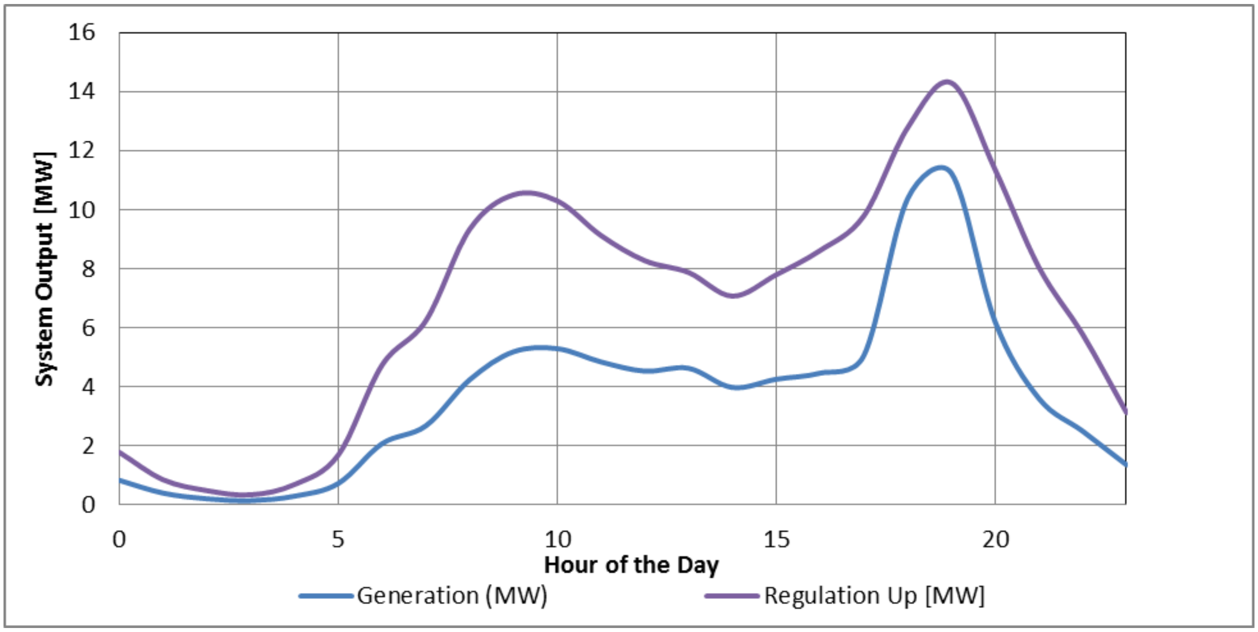


Figure E-9. Profile for the battery system in the 35-MW Waena + transmission line scenario.

APPENDIX F: SENSITIVITY ANALYSIS

Reserve Requirement Formulations

As mentioned earlier in this report, the spinning reserves requirement formulation used in the model in this report is that proposed by the ongoing Solar Integration Study (SIS). Figure 2 illustrates both the SIS reserve requirement and existing reserve requirement in place within the Maui Electric Company (MECO) system.

Table F-1 highlights the differences in wind curtailment that result from the two different spinning reserve formulations. There is almost a 6% difference in wind curtailment between the reference cases of the different reserve formulations. As more storage is added to the system, the wind curtailment difference between the two reserve formulations becomes smaller. The general trend towards increased wind generation as more storage is added to the system is the same under each reserve formulation.

Table F-1. Wind Curtailment and Generation for the SIS Reserve Formulation and the Current Reserve Formulation.

		Total Wind Curtailment (%)		Wind Generation (GWh)	
Scenario Name	**KPP Status**	**SIS Reserve Formulation**	**Existing Reserve Formulation**	**SIS Reserve Formulation**	**Existing Reserve Formulation**
Reference Run	available	16.5%	22.3%	256.3	238.2
10-MW/15-MWh BESS	available	14.0%	16.9%	263.9	255.0
10-MW/70-MWh BESS	available	9.5%	13.8%	277.7	264.4
10-MW/70-MWh BESS, no K4	no K4	7.1%	11.9%	284.9	270.3
25-MW Waena	no K3/K4	10.1%	12.6%	275.9	268.1
25-MW/175-MWh BESS	no K3/K4	2.3%	3.1%	299.6	297.2
25-MW/1200-MWh cryogen	no K3/K4	2.4%	2.9%	299.4	297.9
30-MW Waena + 5-MW/35-MWh BESS	not available	6.9%	9.6%	285.7	277.5
35-MW Waena + transmission line	not available	10.0%	12.0%	276.1	270.1

Table F-2 illustrates the variation in total generation costs and annual system savings between the two reserve formulations. As above, the costs and savings trends are broadly similar between the two formulations. That said, despite the similarity in trends, the different reserve requirements do affect the economics of the storage systems. The existing reserve formulation reduces the annual system savings (as compared to the reference run) by $1 to $2 million (USD 2015) across the board. A consideration of deployment for a storage system will need to take this differential into account if the possibility exists that the current formulation will continue to be used in 2015 and beyond. This also applies in the case of the use of a different reserve formulation than the two considered here.

Table F-2. Total Generation Costs and Annual Savings for the SIS Reserve Formulation and the Current Reserve Formulation.

	SIS Reserve Formulation		Current Reserve Formulation	
Scenario (Note: figures in millions of 2015 USD)	**Total Diesel + Wind Cost**	**Annual Savings (compared to reference run)**	**Total Diesel + Wind Cost**	**Annual Savings (compared to reference run)**
Reference Run	239.8	-	240.6	
10-MW/15-MWh BESS	236.3	3.5	238.1	2.5
10-MW/70-MWh BESS	235.7	4.1	237.7	2.9
10-MW/70-MWh BESS, no K4	234.4	5.4	237.4	3.2
25-MW Waena	237.6	2.2	240.7	-0.1
25-MW/175-MWh BESS	229.7	10.1	231.8	8.8
25-MW/1200-MWh cryogen	234.6	5.2	236.8	3.8
30-MW Waena + 5-MW/35-MWh BESS	234.1	5.7	237.4	3.2
35-MW Waena + transmission line	236.7	3.1	239.5	1.1

Fuel Pricing

The diesel prices used in this study are projections for prices in 2015. Actual prices may well differ from these projections. To better understand the ramifications of fuel prices that differ from those used in this study, this section examines the study's MECO system runs with both a 25% increase and a 25% decrease in diesel price.

Table F-3 indicates the change in system operating costs and savings relative to the reference case for each fuel price variation as well as for the reference run with the baseline fuel price. As may be expected, a decrease in price results in a reduced economic value for energy storage across the board, whereas an increase in price increases the economic value. For example, considering the 10-MW/15-MWh battery system with the baseline fuel price, savings relative to the reference are $3.5 million USD, with an increase in fuel price of 25%, $4.5 million USD and with a 25% decrease in fuel price, $2.4 million USD. This differential highlights the fact that a deployment of an energy storage system would require the consideration of potential changes in fuel pricing to ensure that the economic case for installing storage would exist if fuel prices do change.

Table F-3. Total Generation Costs and Annual Savings with a Change in Fuel Price.

	25% Fuel Price Increase		25% Fuel Price Decrease	
Scenario (Note: figures in millions of 2015 USD)	Total Diesel + Wind Cost	Annual Savings (compared to reference run)	Total Diesel + Wind Cost	Annual Savings (compared to reference run)
Reference Run Original Fuel Price	239.8	-	239.8	-
Reference Run New Fuel Price	286.1	-	193.5	-
10-MW/15-MWh BESS	281.7	4.5	191.1	2.4
10-MW/70-MWh BESS	280.5	5.7	190.9	2.5
10-MW/70-MWh BESS, no K4	278.6	7.6	190.5	3.0
25-MW Waena	282.6	3.5	192.4	1.1
25-MW/175-MWh BESS	272.6	13.6	186.8	6.7
25-MW/1200-MWh cryogen	285.2	7.6	194.0	3.5
30-MW Waena + 5-MW/35-MWh BESS	278.3	7.8	189.8	3.7
35-MW Waena + transmission line	281.8	4.3	191.4	2.1

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