

Utilization of a Validated Power System Model on Two Scenarios: Base Case and High Wind Penetration

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GE Global Research

Hawaii Roadmap Phase 2

Strategic Energy Roadmap for the Big Island of Hawaii

Deliverable # 5

*Interim Report:
Preliminary Results of the Scenario Analysis*

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Executive Summary

In this report, preliminary results of the Big Island power system model validation and scenario analysis are presented. The business-as-usual and higher wind penetration scenarios have been built in both the production cost and dynamic simulation tools. The “higher wind penetration” scenario will be further evaluated in this phase of the program. After the project team has evaluated and reviewed the results of these two scenarios, the remaining scenarios will be constructed and analyzed as part of this program.

The outcome of the Hawaii Energy Roadmap is a validated power systems model for the Big Island, a quantitative evaluation and comparison of forward-looking energy scenarios, and a capability to quantify and address the energy challenges that face Hawaii’s energy system through power system modeling and demonstration activities. As this phase of the program progresses the team will use the results of this study to identify other research activities and demonstration projects on the Big Island.

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1.0 Background

Hawaii must make decisions about its energy future. Ideally, energy should be abundant, reliable, affordable, environmentally friendly, emissions-free and petroleum-independent. However, these characteristics really represent trade-offs; for example, a highly reliable system costs more, and a balance must be struck between the costs of increasing the reliability of energy supply versus the costs (economic, social, and public health and safety) of not having energy when it is needed. Deciding on this balance is critical for the State. Such a debate depends upon having accurate assessments of the effects of energy technology, policy, and design choices. New technologies in renewable energy, energy use, energy conversion, transmission, and storage offer opportunities to provide clean, reliable, and secure energy for Hawaii at less cost. The purpose of the Hawaii Energy Roadmapping Study is to provide Hawaii with the capability to objectively evaluate its energy options and their true costs and environmental consequences. The Hawaii Energy Roadmapping Study is an evaluation of the Big Island’s future electricity and transportation energy options with respect to local goals and future world conditions from a technology-neutral perspective.

2.0 Introduction

In Phase 1 of the program, baseline transportation and electricity models were developed, calibrated and validated against actual conditions. In Phase 2 of the program, stakeholders were engaged early in the process to identify key metrics, energy goals, technologies and policies of interest. The stakeholder input was translated into themes, which guided the scenario selection process. Based on the results of these stakeholder interviews, four scenarios were outlined by the project team. On September 27, 2007 the stakeholders assembled in Hawaii to hear the results of the Phase 1 analysis and the results of the stakeholder interviews. Both of these topics were described in earlier Reports. At the summit, four scenarios were outlined and stakeholder input was solicited once again. The process diagram is shown in Figure 1. There was general agreement among the stakeholders with the overall objectives and technologies specified for each scenario.

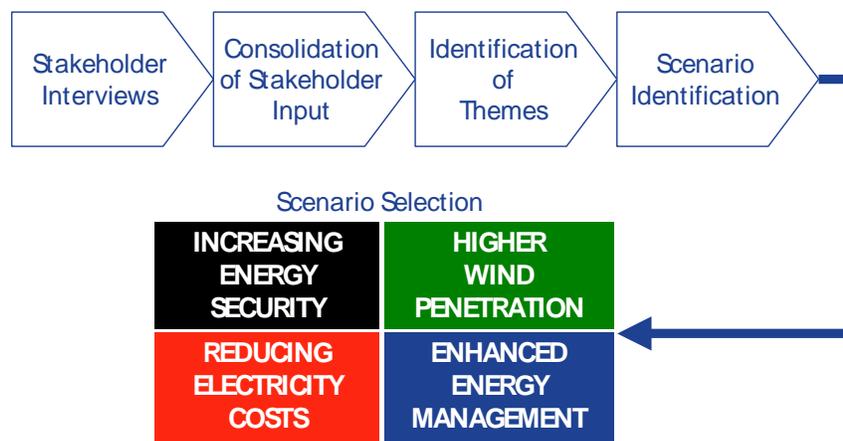


Figure 1. Scenario selection process diagram

The Transportation Model has been developed and validated against data provided in the 2005 Hawaii Databook. Additional data and information were received from the Country of Hawaii Energy Office, from management at the airports on the Big Island, and from other organizations on the island and in the State. The transportation fleet, fuel type and vehicle type breakdown were used in conjunction with fuel demand forecasts, fuel price projections, emissions data, and land use information to evaluate economic, environmental, and sustainability metrics.

The Electricity Model consists of two specific simulation tools: production cost modeling and dynamic (or transient) modeling. The production modeling considers the dispatch and constraints of all generation on an hourly basis and provides outputs such as the emissions, electricity production by unit, fossil fuel consumption, and variable cost of production. For example, if 10MW of wind power were added to the island, and certain assumptions were made about the spinning reserve needed to maintain system stability, how would the total variable cost of production, overall emissions and GWh by fuel type change?

The dynamic model considers shorter timescales (sub-hourly). This is a necessary tool to determine if the decisions made in the longer timescales (production model) affect the system stability in the shorter timescale. This model can be used to determine the short timescale impacts of various decisions. For example, if 10MW of wind power were added to the island it would be necessary to determine the impact of alternative decisions for maintaining system stability (i.e., how much additional spinning reserve would be needed or how much energy storage would be needed).

Significant interaction with the HELCO and HECO teams has resulted in high-resolution models of more than adequate fidelity for a forward-looking scenario analysis. The results of the validation exercise and initial scenario analysis will be presented in this document.

The purpose of the modeling and analysis effort was to provide a baseline measure of electrical and transportation systems performance that would be used as a starting point for infrastructure evolution scenarios that explore alternative energy futures for the Big Island. In this report, preliminary results of the baseline “business-as-usual” scenario and two additional scenarios (“higher wind penetration” and “enhanced energy management”) will be presented.

3.0 Modeling Approach and Validation

This project was focused on providing a foundation from which simulations can be used to provide quantitative information necessary for evaluating the electric infrastructure. The model aimed at capturing technical aspects of challenges related to regulation, frequency control, load following and unit commitment within the transmission system capabilities associated with the present infrastructure, including intermittent resources such as wind generation. The quantitative analysis covered a broad range of timeframes, including:

- Seconds to minutes (regulation and frequency control) – Dynamic simulation
- Minutes to hours (load following, balancing) – Dynamic simulation

- Hours to days (unit commitment, day-ahead forecasting and schedules) – Production cost simulation

The Big Island grid is a dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. From a control perspective, the load is the primary independent variable – the driver to which all the short-term controllable elements in the power system must be positioned and to which it must respond. There are annual, seasonal, daily, minute-to-minute and second-to-second changes in the amount (and nature) of load served by the system. The performance of the power system is highly dependent on the ability of the system to accommodate changes and disturbances while maintaining quality and continuity of service to the customers.

There are several timeframes of variability, and each timeframe has corresponding planning requirements, operating practices, information requirements, economic implications and technical challenges. Much of the analysis in the first phase of the project was aimed at quantitatively evaluating the impact of existing HELCO assets, including wind resources, in each of the timeframes relevant to the performance of HELCO power system. In the longest timeframe, planners look several years into the future to determine the infrastructure requirements of the system based on capacity (or adequacy) needs. This timeframe includes the time required to permit and build new physical infrastructure. In the next smaller timeframe, day-to-day planning and operations must prepare the system for the upcoming diurnal load cycles. In this timeframe, decisions on unit commitment and dispatch of resources must be made. Operating practices must ensure reliable operation with the available resources. During the actual day of operation, the generation must change on an hour-to-hour and minute-to-minute basis. This is the shortest timeframe in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions made the day ahead are implemented and refined to meet the changing load. In the shortest timeframe, cycle-to-cycle and second-to-second variations in the system are handled primarily by automated controls. The system's automatic controls are hierarchical, with all individual generating facilities exhibiting specific behaviors in response to changes in the system that are locally observable (i.e., are detected at the generating plant or substation). In addition, a subset of generators provide regulation by following commands from the centralized Automatic Generation Control (AGC), to meet overall system control objectives including scheduled interchange and system frequency.

In the context of the Big Island, the infrastructure has been modeled at different levels:

- Transient modeling, in the seconds-to-minutes timescale, to determine stability and transient performance of the island grid, and
- Production cost modeling, in the hours-to-days timescale, to determine the operating economics of the power system.

3.1 Transient and Long-term Dynamics Simulation

Transient and long-term dynamics simulations are used to estimate system behavior (such as frequency) during wind power fluctuations and system events. This type of modeling can be used to understand the impact of transient operation of different generators on system frequency in a seconds timeframe and is used by utilities to ensure that the system frequency remains

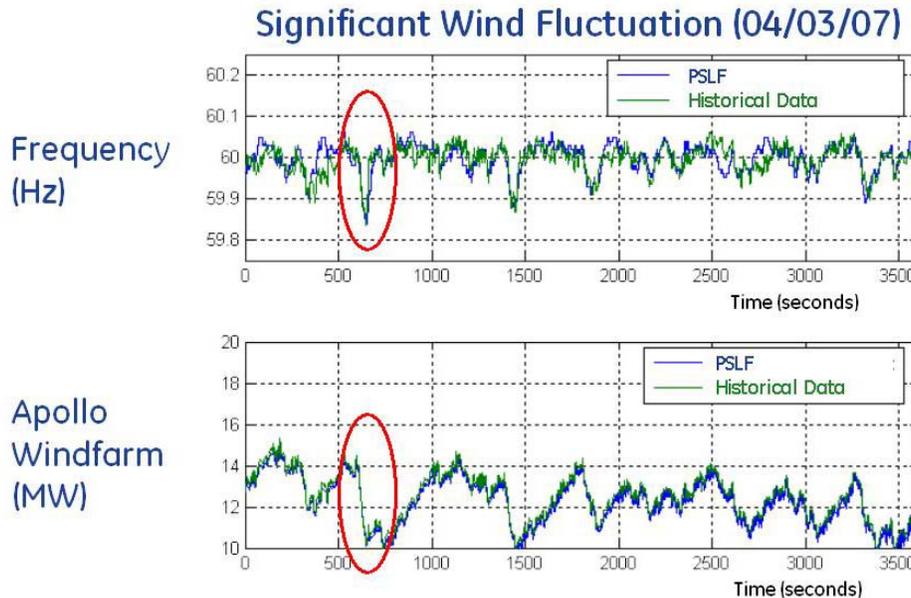


Figure 3. System frequency comparison between historical data and the dynamic model for a one-hour window on April 3, 2007.

At approximately 600 seconds into the simulation, the Apollo wind farm decreases its power output. This caused a frequency excursion of $\sim 150\text{mHz}$. The model was able to capture this frequency excursion as well as the others observed during the one-hour window. In addition to this one-hour window, two other one-hour windows were compared. The model accurately captured the system frequency performance for this window and the other two windows, for normal operating conditions. Both HECO/HELCO and the project team agree the model provides adequately high fidelity for a forward-looking scenario analysis. In fact, the degree of accuracy demonstrated in the back-casting examples is considerably above the accuracy generally achieved for these types of forecasting models. Thus, the model more than meets the needs of the scenario analyses to be conducted as part of this effort.

GE's approach to modeling the dynamic behavior of the HELCO grid has differing levels of model fidelity, depending on the timescale represented. The fidelity of the representation of short-term dynamics is limited primarily by the quality of the governor model database made available by HELCO. In contrast, the representation of long-term dynamics can be expected to be of less fidelity because it is limited not only by the accuracy of the governor/power plant models, but also by the modeling of the AGC: the controller that dispatches some generation to maintain system stability.

Short-term dynamic models of the HELCO grid are implemented in PSLF. This tool is a widely used load flow and transient stability analysis package. This commercially available tool has a long history of application in the electric utility industry. The primary source of model uncertainty and error for short-term dynamic simulations will come from imprecision of component model parameters of various electric power assets in the HELCO grid (primarily generators and governor models).

Long-term dynamic models of the HELCO grid were developed in PSLF. These simulations are two to three orders of magnitude longer than typical short-term stability simulations. The long-term simulations are performed with detailed representation of generator rotor flux dynamics and controls, typical of short-term dynamics. The models that are modified or added to capture long-term dynamics are AGC, load, and as-available generation variability. Phenomena that can affect long-term dynamic behavior, such as long duration power plant time constants (e.g., boiler thermal time constants), slow load dynamics (e.g., thermostatic effects), and human operator interventions (e.g., manual switching of system components) were not included in this model.

The PSLF simulation outputs include estimations of:

- System frequency fluctuations due to load and wind variability,
- Voltages throughout the system,
- Active and Reactive power flows,
- Governor operations,
- Primary frequency regulation needs, and
- Load following regulation needs.

3.2 Production Cost Simulation

Throughout the year HELCO has to make decisions about which generators should be used to produce electricity in each hour of the day (commitment and dispatch). This decision depends on many constraints, including the cost of each generator, the capabilities of the transmission system, and rules about when each generator can be operated. The model includes representation of the HELCO transmission system and relevant characteristics of each generating unit, such as the maximum and minimum power output, heat rate (thermal efficiency) as a function of production level, emissions, minimum downtime between starts, start-up costs, operating constraints, and maintenance and forced outages.

Production cost modeling of the HELCO system was performed with the GE's Multi Area Production Simulation (MAPS™) software program. This commercially available modeling tool has a long history of governmental, regulatory, independent system operator and investor-owned utility applications. This tool was used to simulate the HELCO production for 2006. The production cost model provides the unit-by-unit production output (MW) on an hourly basis for an entire year of production (GWh of electricity production by each unit). The results provide information about the variable cost of electricity production, emissions, fuel consumption, etc.

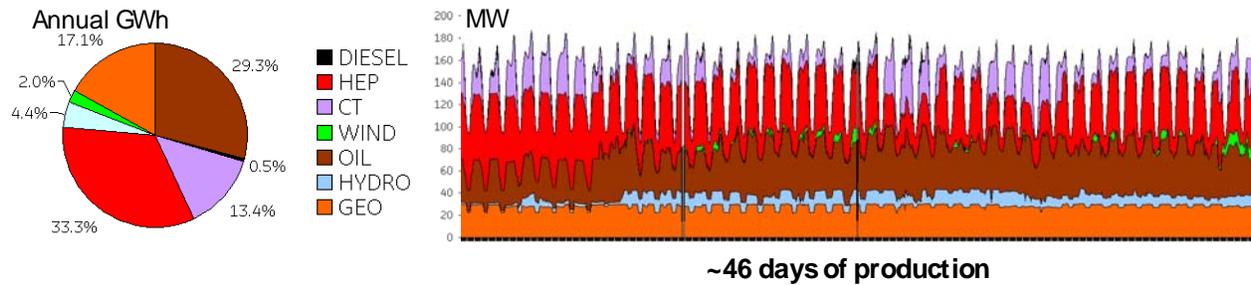
The overall simulation algorithm is based on standard least marginal cost operating practice. That is, generating units that can supply power at lower marginal cost of production are committed and dispatched before higher marginal cost generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum spinning reserve, stability limits, as well as the physical limitations and characteristics of the power plants. Significant input has been received from HELCO and multiple model iterations have been performed.

Prices that HELCO pays to third parties for energy are not, in general, equal to the cost of production for the individual unit, nor are they equal to the systemic marginal cost of production.

Rather, they are governed by power purchase agreements (PPAs). The price that HELCO pays third parties for energy production is reflected in the simulation results insofar as the conditions of the PPAs can be reproduced.

In order to validate the model, 2006 load, hydro and wind data were provided by HELCO for an entire year of production. An entire year was simulated in the production cost tool. The results for each unit in the HELCO grid included the number of starts, hours on-line, annual power production, fuel cost, capacity factor, variable O&M cost, fuel consumption, emissions (NO_x, SO_x, CO₂). Based on fuel type, the results of the simulation were compared to historical data (see Figure 4). The results are separated into seven generator types: Diesel units, Hamakua Energy Partner’s combined cycle plant (HEP), Combustion Turbines (CT), Wind power, Oil-fired steam turbines (Oil), run-of-the-river hydro plants (hydro), and Puna Geothermal Venture’s geothermal plant (GEO).

2006 Historical Production



MAPS Production Cost Simulation

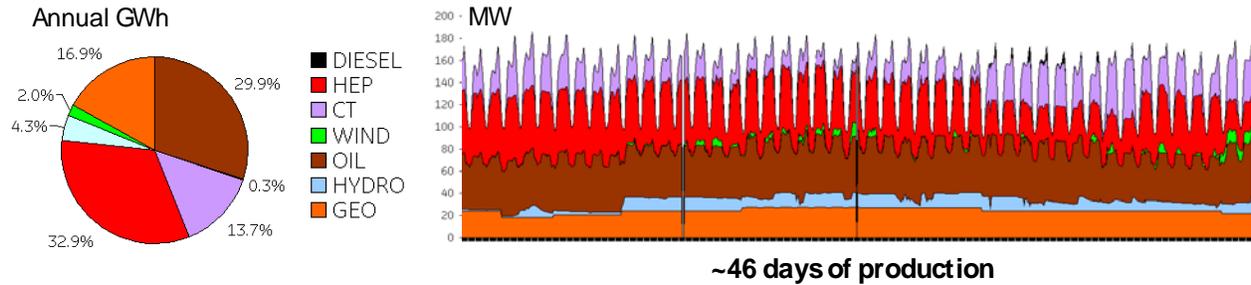


Figure 4. Electricity production on the Big Island, by fuel type

In Figure 4 the aggregate GWh of electricity production from the simulation was compared to historical data. The historical electricity production and MAPS simulation results compared within 1%. Although the model is unable to capture unique operating conditions, such as generator dispatch due to operator intervention, and the exact hourly dispatch of each unit throughout the entire year, the overall aggregate comparison of electricity production by fuel type indicates a highly accurate model has been developed.

Similar trends are observed between historical data and the simulation results; however it should be noted that outages in MAPS (maintenance or forced) do not necessarily occur at the same time of year as the historical data. For example, the HEP production in the MAPS simulation decreases for nine days near the end of the window shown in Figure 4, while according to

historical data the actual HEP outage occurred at a different time of the year. This observation is not of consequence to the type of forward-looking analyses performed in this study, but should be noted. In addition to comparing the annual electricity production by fuel type, the hourly production, running hours, number of starts, and the heat rate curve for each unit were compared to HELCO data and actual historical performance. It should be noted that the production cost model considers heat rate and a variable O&M cost, but the models do not include an explicit heat-rate penalty or an O&M penalty for increased maneuvering that may be a result of incremental system variability due to as-available renewable energy systems (especially wind).

Based on the results of the validation exercise, the Hawaii Electric Light Company (HELCO), the Hawaiian Electric Company (HECO), the Hawaii Natural Energy Institute (HNEI) and the General Electric Company (GE) were satisfied with the accuracy of the production cost and dynamic models, and were comfortable moving to the scenario analysis phase of the project. The degree of accuracy demonstrated for both the production cost and dynamic simulation models are considerably above the accuracy generally achieved for forecasting models. Thus, the model more than meets the needs of the scenario analyses to be conducted as part of this effort.

3.3 Sensitivity Analyses

With validated production cost and dynamic models of the HELCO grid a series of parametric studies were performed. Incremental changes to the baseline model were performed. These changes provided input to scenario development about the impact of certain technology choices on key metrics, such as emissions, production cost, percent of imported petroleum, and percent renewable energy content. Some of the incremental changes considered were:

1. Supply-side: Generation & other technologies
 - a. Geothermal power,
 - b. Wind power,
 - c. Solar power,
 - d. Spinning reserve,
 - e. Energy storage (scheduled charging), and
 - f. Energy storage (market-rational/forecasting).

2. Demand-side: Load & other technologies
 - a. Load,
 - b. Nighttime trough filling,
 - c. Peak load shaving, and
 - d. Scaling of the load signature by load factor.

In each case, a very small change is made, providing a sense of which actions would have the largest incremental effect. These sensitivities, in turn, provide direction in determining directions for the stakeholders to consider. “Incremental” and “relative” are key qualifiers, as the reality of the Big Island system is that it is an extremely complex and highly non-linear system. Directionally correct insight implies neither exactness nor feasibility on a large scale. Nevertheless, the results suggest, for just one example, that technology choices that reduce spinning reserve requirements will have a significant beneficial impact on fossil fuel

consumption and emissions. Addition of wind generation will tend to displace fossil fuel consumption, but will add to spinning reserve requirements. It is these types of approximate though quantitative results, that can provide insight for each scenario considered in Phase 2.

As an example, if 1MW of wind power were added to the HELCO grid at the Apollo wind farm, production cost model results show that 37,000 MMBtu of energy from fossil fuel generation would be displaced by the wind energy on an annual basis. As a result, carbon emissions would be reduced, as would the amount of fossil fuel imported to the island. The production cost model can be used to quantify the variable cost of electricity production based on the power purchase agreements with each of the independent power producers and based on the fuel, operation, start-up, and maintenance costs of each generator.

	Fuel Use		Emissions (tons)		
	GWh	MMBtu	NOx	SOx	CO ₂
Combined Cycle	-2.1	-15545	0	-2	-1352
Combustion Turbine	-1.3	-13905	-1	-2	-1245
Diesel	0.0	-341	0	0	-29
Puna Geothermal	0.0	0	0	0	0
Small Hydro	0.0	0	0	0	0
Steam Oil	-0.6	-7582	-1	-1	-726
Wind	4.1	0	0	0	0
Solar	0.0	0	0	0	0
Grand Total	0.1	-37374	-2	-6	-3352

Figure 5. The annual impact of adding 1MW of wind power to the Apollo wind farm.

However, this discussion is much more complex than has been described thus far. The addition of wind power to the HELCO system could require additional regulation; generation that produces electricity at a sub-optimal, part-load, operating conditions in order to address swings in wind power production. This increases the amount of fossil fuel consumed and increases the island’s carbon emissions. New technologies, such as energy storage, may be considered in order to address impacts of wind intermittency on the system frequency. Storage technologies could reduce HELCO’s variable cost of production and reduce the amount of fossil fuel consumed on the island. However, there is a capital investment needed for such a technology. From a technical perspective, the dynamic simulation (or transient simulation) tool can be used to illustrate the impact of various decisions (amount of spinning reserve, size of energy storage, etc.) on system stability. From an economic perspective, if wind power producers are contractually paid more than other generating assets that could generate electricity in its place, there is a cost adder associated with increased use of wind power.

This discussion reveals the economic and technical complexity of this type of power system modeling. By combining both production cost and dynamic modeling, much information can be provided to the Department of Energy (DOE), the utilities, and the State government about the impacts of technologies and policies on key metrics related to economics and sustainability. By using both production cost and transient simulation tools to analyze “what-if” scenarios, a more thorough analysis can be performed, which provides greater insight into the technical and economic tradeoffs of these types of technology choices.

The models developed and presented here represent a mixture of standard electric power system engineering tools, of the type regularly used by utilities, and some novel simulations of types not typical within the utility system planning repertoire. The study is not a standard system planning study, nor is it meant to replace utility planning or the HELCO Integrated Resource Plan (IRP) exercise. Instead, scenario analysis can provide those familiar with the HELCO system directionally correct sensitivities, such as a change in the variable cost of production or emissions associated with a particular technology deployment decision. Insofar as it is possible to be technology-neutral, the project team examined technology deployments that achieve common themes or goals cited by the stakeholders during our interviews with them.

4.0 Results

Preliminary results of the baseline “business-as-usual” and higher penetration wind scenarios are presented. The scenario analysis presented here is not meant to be exhaustive, nor is it meant to replace utility planning. Instead, the scenarios represent two specific cases that were evaluated using the models. These scenarios allow the team to make “directionally-correct” observations about certain energy technology choices.

4.1 Baseline: Business-as-Usual

The baseline model, termed “business-as-usual,” relies on the current IRP approach to project the island’s electricity needs in the 2018 study year. A 16MW steam turbine (ST7) will be deployed at Keahole before 2018. This deployment enables dual train combined cycle operation in conjunction with two existing combustion turbines (CT4 and CT5). According to HELCO’s IRP, the deployment of ST-7 will allow HELCO to meet its capacity needs for the next several years¹. As a first step in developing the baseline model, the load curve for 2006 was projected to 2018 based on the IRP projections in peak demand and the 2006 historical load factor (Figure 6).

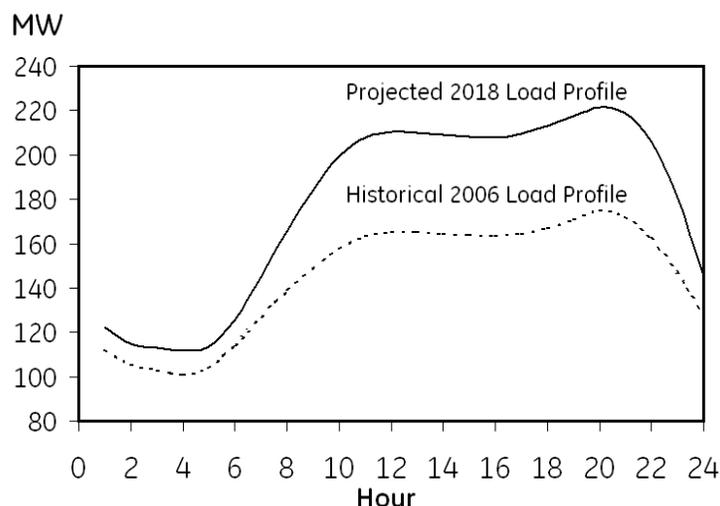


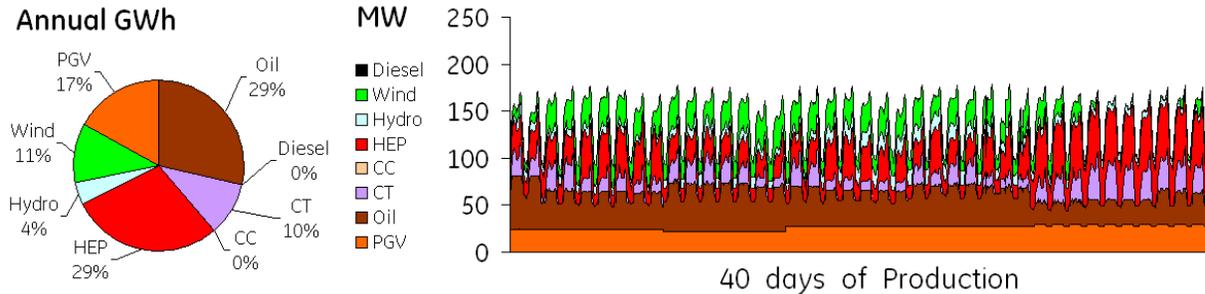
Figure 6. Average daily load profile in 2006 (historical) and 2018 (projected).

Using the validated 2006 model as a starting point, the “business-as-usual” scenario was constructed in the production cost model (MAPS). The results of the production cost model are

¹ *Ibid*, p.1-29

shown in Figure 7. The annual GWh of electricity production by fuel type is shown on the left, and approximately forty days of hourly production are shown on the right for both the historical model (2006) and the new baseline “business-as-usual” scenario (2018). The results are separated into eight generator types: Diesel units, Wind power, run-of-the-river hydro plants (hydro), Hamakua Energy Partner’s combined cycle plant (HEP), HELCO’s Keahole combined cycle plant (CC), Combustion Turbines (CT), Oil-fired steam turbines (Oil), and Puna Geothermal Venture’s geothermal plant (PGV).

Baseline Historical Model



Baseline 2018: “Business-as-usual”

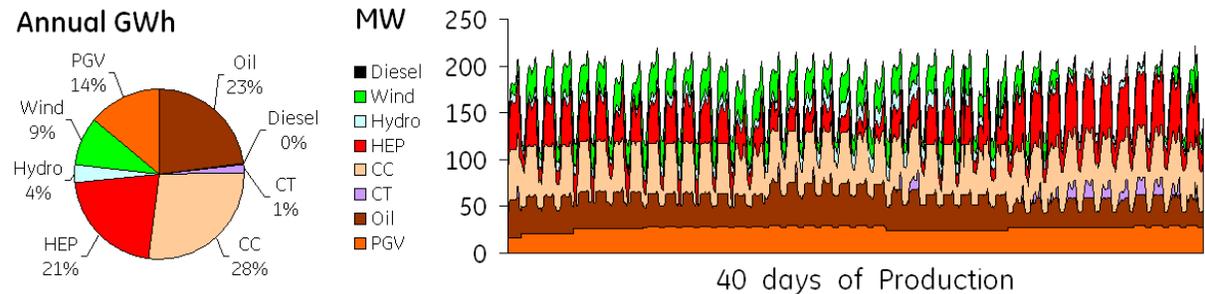


Figure 7. Simulation results for the 2006 historical model and the 2018 “business-as-usual” baseline model.

Based on these results, some general observations can be made. The load curve grew from the historical value to the “business-as-usual” scenario. The percentage of total electricity produced by wind energy decreased because no new wind farms were developed. It should be noted that all of the HELCO’s must-run requirements were unchanged in the “business-as-usual” scenario.

The long-term dynamic model can be used to estimate frequency excursions and assess system stability for a given scenario. The “business-as-usual” scenario was constructed in the dynamic model, PSLF for various load conditions and wind power generation levels. Wind power variations from an historical window of 2-second data from May 23, 2007 were used to drive the 2018 “business-as-usual” scenario simulations. This enabled comparisons between the “business-as-usual” scenario and historical data. The dynamic simulation was initialized with the same load and generating units as dispatched by the production cost model. Figure 8 shows the results of the one-hour simulation.

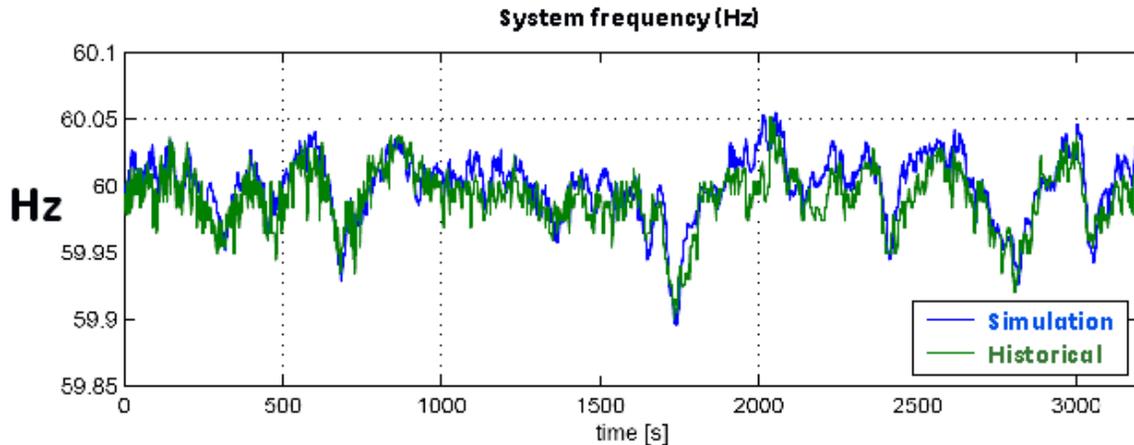


Figure 8. "Business-as-usual:" Comparison between historical data for 2007 (green) and simulation results for a one-hour simulation with low load and variable wind power generation (blue).

The frequency performance for this one-hour window exhibits similar trends and features as the historical window. The “business-as-usual” scenario for 2018 will be used as the baseline for comparison with the other scenarios.

For all the scenario analyses considered in this study, an iterative approach has been taken:

1. The scenario will be built in the production cost and dynamic models.
2. The stability of the scenario will be evaluated in the dynamic model.
3. Revisions to the scenario will be made based on the results of the dynamic model.
4. The new scenario will be re-run in the dynamic and production cost models.
5. Economic, environmental and performance metrics will be quantified.

4.2 Scenario 1: Higher Wind Penetration

The higher wind penetration scenario is motivated by a trend on the Big Island for additional wind farm developments. As the island reaches higher penetrations of wind, HELCO staff has indicated that system stability, already at risk, may be further degraded.

High-resolution wind maps reveal that the offshore wind speeds are too low in regions having the shallow depths necessary for today’s offshore wind technologies. Therefore, in this scenario, a significant increase in land-based wind power, from 32.5MW to 84.5MW, was considered.

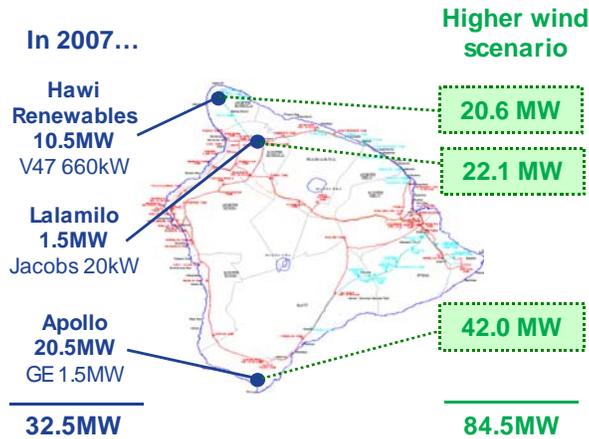


Figure 9. Present wind power installations and installed wind power for the higher wind penetration scenario.

As a first step, the higher wind penetration scenario was built in both the production cost model (MAPS) and the dynamic model (PSLF). The electricity production, by type, is shown for an entire year of the production cost simulation (see Figure 10). The hourly production, by type, is shown for forty days of the year. The same HELCO rules were imposed on the scenario as in the business-as-usual case.

Higher Wind Penetration Scenario

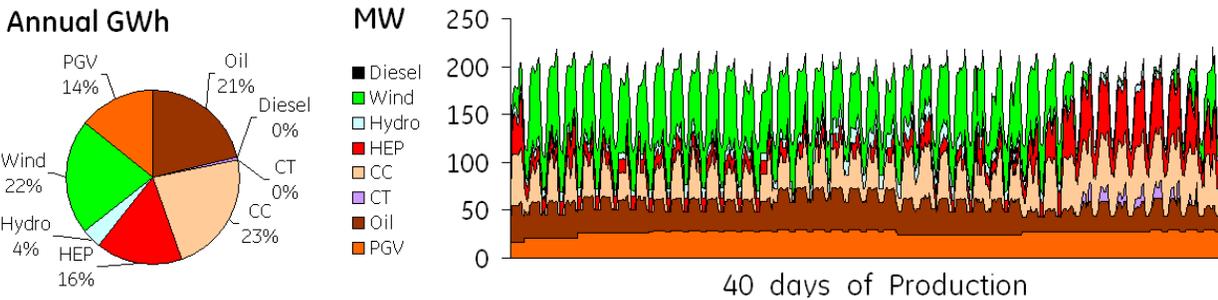


Figure 10. First iteration of the higher wind penetration scenario.

As a second step, the dynamic model was used to estimate the impact of the additional wind power, postulated in this scenario, on grid stability and frequency variations. The same one-hour window as the “business-as-usual” scenario was considered for the higher wind penetration scenario. Since significantly more wind power capacity is present for this scenario, as compared to the “business-as-usual” scenario, the same decrease in wind speed results in a larger decrease in wind power production. Figure 11 shows the system frequency obtained during a low load condition with variable wind generation. The maximum frequency excursion and RMS deviation of frequency are significantly larger than the historical data.

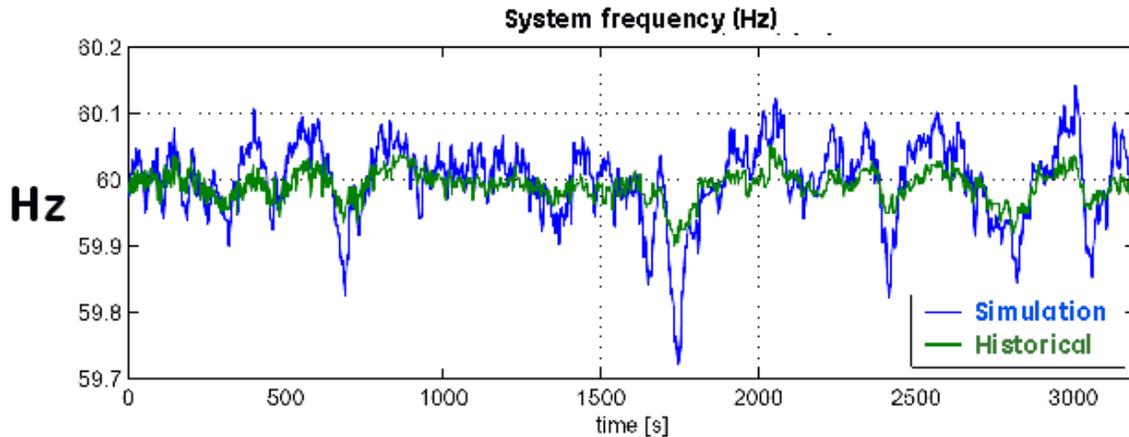


Figure 11. "Higher wind penetration:" Comparison between historical data for 2007 (green) and simulation results (blue) for a simulation with low load and variable wind power generation for the higher wind penetration scenario.

Sensitivities of these results to the load level, amount of primary frequency reserve, and various mitigating measures will be performed. This will allow the team to quantify the performance impact for each new scenario and for each case considered as part of a scenario. In the higher wind penetration scenario, a significant frequency excursion is observed in the one-hour window. Stabilization devices in the form of energy storage could be used to increase system stability. These types of revisions to the higher wind penetration scenario were considered, and will be discussed later in the report.

Recognizing that energy storage may reduce system frequency excursions, a specific storage technology could be considered in the production cost model. Pumped hydro storage at Puu Anahulu (30MW, 5hrs of storage) was identified as one of the potential resources in HELCO's IRP. This facility was modeled in the production cost tool. The preliminary results of adding the 30MW (5hrs of storage) pumped hydro storage to the higher wind penetration scenario are shown in Figure 12. It should be noted that, in this first iteration, the pumped hydro storage has not been tuned for the balance of economy and operability.

Higher Wind Penetration Scenario + 30MW (5hr) Pumped Hydro Storage

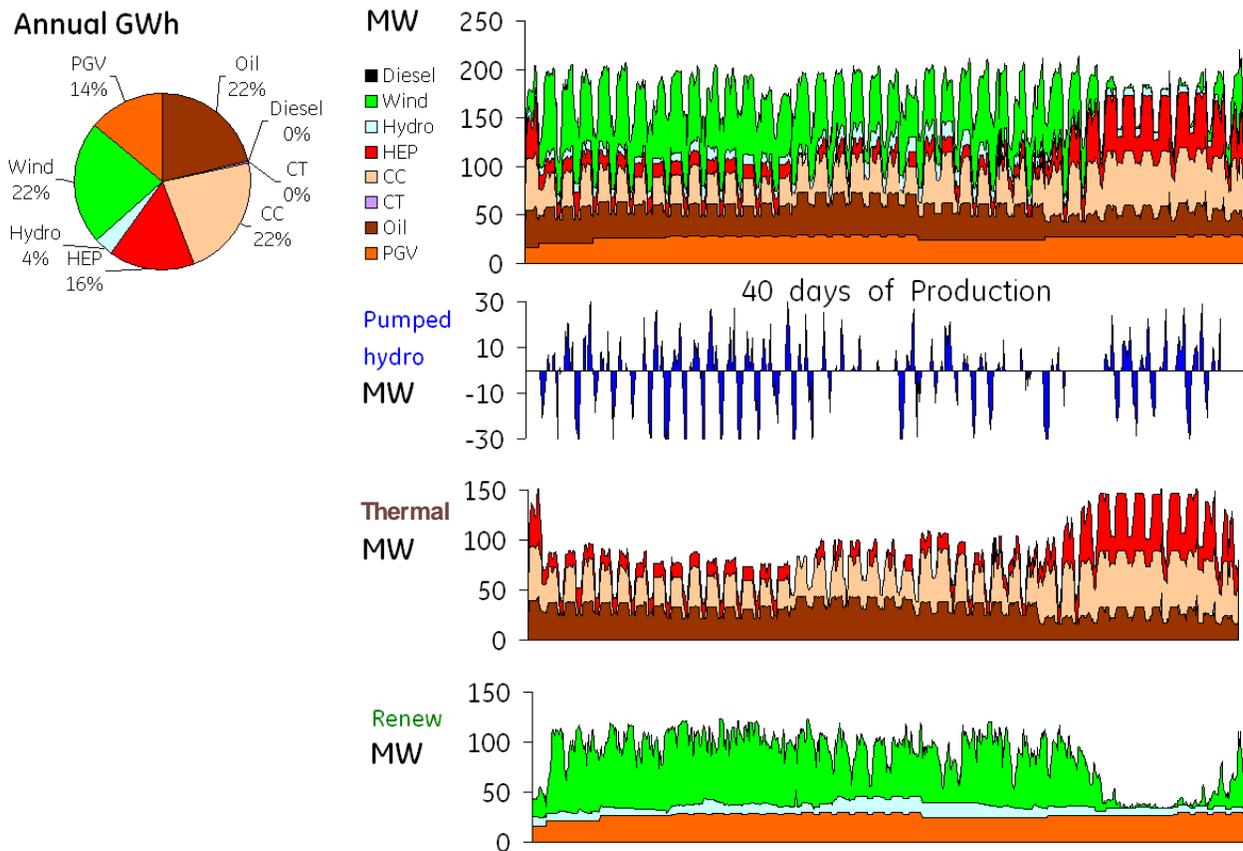


Figure 12. First iteration of the higher wind penetration scenario + 30MW (5hr) of pumped hydro storage. Note that the pumped hydro storage has not yet been tuned for balance of economy and operability.

Based on these results, the pumped hydro storage can be seen to reduce the hour-to-hour fluctuations of each fuel type. Additionally, pumped hydro storage has enabled variable cost reduction by “charging” at night, when the variable costs are lower, and “discharging” during the day, when the variable costs are higher.

As was mentioned previously, the dynamic performance of this scenario can be illustrated in PSLF, and additional revisions can be performed. One method for quantifying the frequency performance of various approaches is the RMS frequency deviations for the one-hour window. The RMS frequency deviation was calculated for the variable speed pumped hydro case described above, and the following six other cases (see Figure 13):

1. Baseline “business-as-usual” scenario,
2. Higher wind penetration scenario,
3. Higher wind penetration scenario with a 1MW stabilization device,
4. Higher wind penetration scenario with a 2MW stabilization device,
5. Higher wind penetration scenario with a 5MW stabilization device, and
6. Higher wind penetration scenario with a 2MW, rate limited, stabilization device.

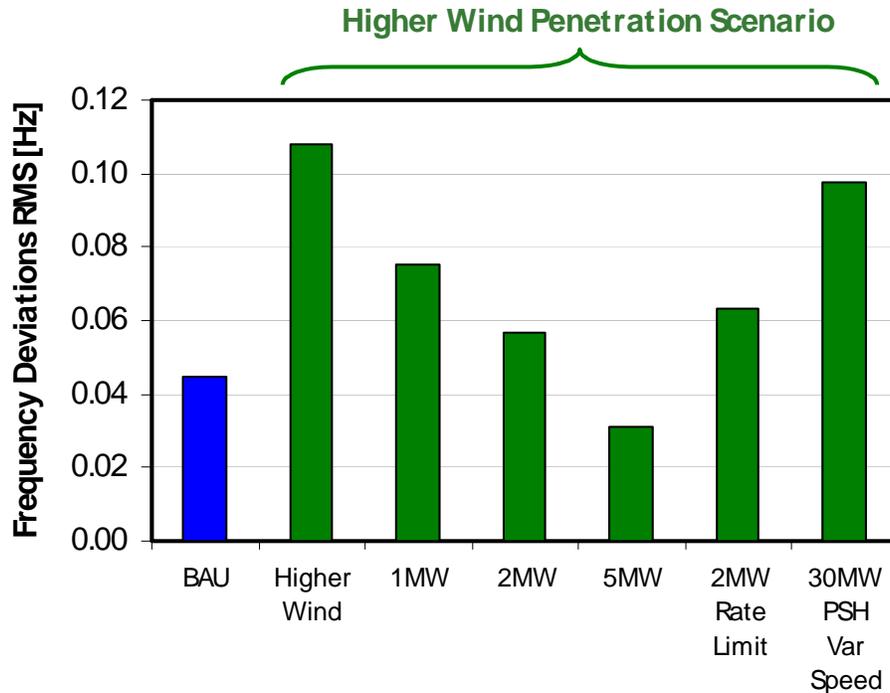


Figure 13. Frequency performance of variability mitigating measures

The higher wind penetration scenario exhibited considerably worse RMS frequency deviation than the “business-as-usual” scenario. Stabilization devices with increasing power ratings significantly improved the system performance. The energy storage requirements in the cases considered here were less than 5 min (at full power). A 5MW stabilization device was considered for the higher wind penetration scenario. For this case, the RMS frequency deviation decreased to less than that of the “business-as-usual” scenario. Even a rate limited 2MW stabilization device improved the system frequency. An aggressive (but feasible) frequency regulation control loop was used for each storage device.

The addition of a 30MW variable-speed pumped hydro storage device (with frequency control capabilities in pumping mode) did not greatly improve the RMS frequency deviation in this window. However, the pumped hydro storage controller was assumed to have a standard droop response and was not optimized for system frequency improvements. **These cases, and other higher wind penetration scenario cases, are still in development and have not been validated for operability or feasibility.**

The dual approach of production cost and dynamic modeling offers a capability to postulate and evaluate scenarios in each of the timescales of interest. The results from the dynamic model can be used to identify and specify additional technologies or operating practices needed to maintain system stability in the sub-hourly timeframe. The results from the production model can be used to quantify the economic metrics associated with commitment and dispatch in the hour-to-hour timeframe. Together, these validated tools allow the team to identify, evaluate, quantify, and compare forward-looking scenarios that achieve some of the island’s key energy objectives.

5.0 Conclusions

Preliminary results of the scenario analysis were presented in this report. The production cost and dynamic simulation model validation exercise was summarized. The baseline “business-as-usual” scenario was built in both the production cost and dynamic simulation models, and the results were illustrated in this report. Preliminary results of the production cost and dynamic simulations were presented for the “higher wind penetration” scenario. The “higher wind penetration” scenario will be further evaluated in this phase of the program. After the results of these two scenarios have been further evaluated, and reviewed by the project team, the project team will define the remaining scenarios to be completed as part of this program.

As this phase of the program progresses, the team will use the results of the model to identify potential research activities and demonstration projects on the Big Island. The multi-year relationship between the General Electric Company (GE), the Department of Energy (DOE), the Hawaii Natural Energy Institute (HNEI), the Hawaii Electric Company (HECO), and the Hawaiian Electric Light Company (HELCO) represents a strong public/private partnership, capable of leveraging private business support and commercializing R&D activities. The project team consists of organizations that span the energy market, including those that research, develop, demonstrate, innovate, purchase, service, and utilize these technologies. Through the partnership, the GE team would like to continue to identify and address the challenges that face Hawaii’s energy system.