Grid Stability Modeling in Hawaii
What is it and why is it important?

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GE & HNEI’s Renewable Integration Experience

Previous studies evaluated resource modeling, reserve analysis, economic dispatch, but did not address grid stability in depth.
Technical Review Committee

Gather a group of key stakeholders to review project scope, assumptions, findings and key deliverables to make the study relevant to Hawaii’s utility, policy, and regulatory challenges and opportunities.

The findings and results presented in this analysis does not constitute endorsement by the parties listed above.

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What’s Happening in Hawaii...

Hawaii’s Renewable Portfolio Standard

- 30% by 2020
- 40% by 2030
- 70% by 2040
- 100% by 2045

Rapid Growth of Distributed PV

- 5x growth in 5-years
- >30% of single family homes

Focus on the integration of variable renewable resources due to the fast growth and unique grid challenge, complexities warrant independent engineering & economic studies.
Why is Grid Stability Important?

- Customers want their electricity to be affordable, clean, and reliable... all are important
- Part of a comprehensive analysis for power system planning
- Responds to emergency (contingency) events, not normal operations
- Important at different time scales of system operation; seconds to minutes

Novel solutions are required to maintain grid stability with high wind and solar penetration
Different Types of Grid Stability

A. Capacity adequacy (RPS Study)

B. Variability and regulation reserves (OWITS, HSIS, RPS Studies)

C. Distribution feeder voltage analysis (HECO and others)

D. This Study
   i. Develop a methodology to screen for challenging operations
   ii. Dynamic Frequency Response (Generator & Load trip contingencies)
   iii. Grid strength
   iv. Transmission fault analysis
   v. Integration with electric vehicles, storage, demand response
Overview of Frequency Response

- Generation (supply) and system load (demand) must be balanced at all times.
- This balance is measured by system frequency (nominal frequency = 60 Hz).
- If generation is higher than load, frequency rises above 60 Hz; if generation is lower than load, frequency declines below 60 Hz.
- Contingency events: If a generator or load trips offline, system frequency will change rapidly.

Large frequency deviations lead to under frequency load shedding (UFLS), cascading generator trips, and potentially grid collapse.
Why is Hawaii Unique?

A shared experience with other islanded power systems

**Large Single Contingency**
Must be prepared for the loss of AES coal plant, which can be up to 30% of the grid’s supply

**Low Number of Synchronous Generators**
Oahu has few synchronous generators online and available to provide primary frequency response

**Isolated grids**
Islands cannot rely on neighbors during emergency events for support

**High Level of Renewable Penetration (DPV especially)**
High renewable penetration displaces conventional generation and some of the ancillary services they provide.

Novel solutions are required to maintain grid stability with high wind and solar penetration
Rethinking Stability Requirements

• Traditional method:
  – Overly conservative *worst case* used to design stability criteria
  – Results in inefficiencies and reliance on conventional thermal generators only for grid stability

• Proposed method:
  – Develop procedure to assess system risk at *all hours of the year*
  – Include wind and solar resources, demand response, storage, electric vehicles as mitigating technologies
  – Modify stability criteria based on real time operations

First set of scenarios analyzed:

| Scenario 1: 400 MW DPV, 150 MW CPV, 125 MW Wind | 16% annual W&S |
|                                               | >50% instantaneous |
| Scenario 2: 700 MW DPV, 150 MW CPV, 125 MW Wind | 22% annual W&S |
|                                               | >70% instantaneous |
Methodology for Risk Assessment

Production Cost Simulations (GE MAPS)

Selecting System Dispatch Conditions

Dynamic Stability Simulations (GE PSLF)

Estimating Frequency Response

Production Cost Modeling
Hour-by-hour economic dispatch of all generation over entire year

Selecting System Dispatch Conditions
Develop system risk metric and sample hours

Dynamic Stability Simulations
Validate system risk metric

Estimating Frequency Response
Relate system risk metric to stability simulation and apply to all hours of year
Step 1: Production Cost Simulations (GE MAPS)

Step 2: Selecting System Dispatch Conditions

Step 3: Dynamic Stability Simulations (GE PSLF)

Step 4: Estimating Frequency Response

- Chronological, 8,670 hour dispatch of the Oahu power system
- Dispatch of conventional thermal, wind, and solar generators to efficiently serve the system load
- Provides representative dispatch conditions for use in dynamic simulations
A composite metric was developed to quantify system risk

- **Largest Generator Contingency**: severity of the contingency event
- **Thermal Unit Commitment**: proxy for system inertia
- **Up-reserves online**: amount of frequency response available to the system
- **Legacy DPV online**: proxy for sympathetic DPV tripping

System risk metric = \((g_i \cdot w_g) + (c_i \cdot w_c) + (r_i \cdot w_r) + (d_i \cdot w_d)\)

Where:
- \(g\) is the size of the largest generator contingency.
- \(c\) is the amount of committed thermal unit capacity.
- \(r\) is the amount of up-reserves online.
- \(d\) is the amount of legacy DPV generation.
- \(i\) is the observation of each variable for a given hour of the year.
- \(w\) is the weighting factor applied to each variable.
Select system dispatch conditions for dynamic simulations, based on a wide range of operating conditions (approx. 30)
Example Generator Trip Contingency

- **Step 1**: Production Cost Simulations (GE MAPS)
- **Step 2**: Selecting System Dispatch Conditions
- **Step 3**: Dynamic Stability Simulations (GE PSLF)
- **Step 4**: Estimating Frequency Response

Grid Collapse

- **Step 1**
  - Grid Collapse
  - Shed Load

- **Step 2**
  - 58.5 Hz
  - 57.8 Hz

- **Step 3**
  - SCEN 1
  - SCEN 2

- **Step 4**
  - Grid Collapse
Use this equation to estimate frequency response throughout the year:

\[ y = -0.0005x^2 - 0.1003x + 57.946 \]

With \( R^2 = 0.9235 \)

Process repeated for load-rejection contingencies.
Example Load Rejection Contingency

- **Production Cost Simulations (GE MAPS)**
- **Selecting System Dispatch Conditions**
- **Dynamic Stability Simulations (GE PSLF)**
- **Estimating Frequency Response**

Time (seconds) vs. Frequency (Hz) chart showing:
- SCEN 1: Reaches 61.3 Hz
- SCEN 2: Reaches 61.8 Hz
Step 1: Production Cost Simulations (GE MAPS)

Step 2: Selecting System Dispatch Conditions

Step 3: Dynamic Stability Simulations (GE PSLF)

Step 4: Estimating Frequency Response

Load Rejection Contingency

- **SCEN 1A**
  - \( y = 0.0019x^3 + 0.0402x^2 + 0.2818x + 61.332 \)
  - \( R^2 = 0.9781 \)

- **SCEN 2A**
  - \( y = 0.0014x^3 + 0.0253x^2 + 0.1628x + 60.984 \)
  - \( R^2 = 0.7722 \)

- **SCEN 1B**

- **SCEN 2B**

- **SCEN 1C**
  - \( y = -0.001x^3 - 0.004x^2 + 0.0411x + 60.686 \)
  - \( R^2 = 0.7374 \)

- **SCEN 2C**

Over-frequency droop utility scale RE

Over-frequency droop utility scale & distributed
Key Findings and Observations

- Developed a methodology to evaluate system risk at all hours
- In Scenario 2, wind and solar generation represents 22% of annual load, with times of instantaneous penetration at 70%
- Increased renewables can reduce the contingency severity; highlighting the alignment of economic and stability objectives
- Both generator and load contingencies are manageable with up to 700 MW of DPV, 150 MW of CPV, and 125 MW of wind
  - Grid strength still needs to be evaluated
- Frequency response from both utility-scale and distributed renewables can avoid curtailment
Key Findings and Observations (Generator Trip)

Increased DPV penetration up to 700 MW (with frequency ride-through enabled) does not erode grid stability to a generator trip event with the assumptions evaluated in this study.

- Based on the simulations, the grid was able to survive all of the generator contingency events evaluated, even in the most challenging hours of operation.
- While the expected frequency response in some hours may have been reduced when adding 300 MW of DPV, the net result when evaluating the entire year of operations is a slight improvement in system frequency response to a generator contingency.
- DPV reduces the net load on feeders that are part of the load-shedding system, which decreases the effectiveness of load-shedding to stop rapid declines in frequency.
- The reduced AES output during times of high wind and solar output reduces system risk.
Key Findings and Observations (Load Trip)

With increased renewables, system risk shifts to loss of load contingencies. Absent mitigations, increasing DPV from 400 MW in Scenario 1 to 700 MW in Scenario 2 will significantly erode system stability due to loss of load contingency events.

- Many more hours when frequency excursions could approach over-frequency protection actions
- Greater dependence on thermal units to quickly reduce output to very low levels
- Utility scale renewables and DPV can contribute to the grid’s frequency response with over-frequency governor action
- Due to their power-electronic interfaces, wind & solar response times can be faster than thermal units
- Grid performance improves dramatically when renewable resources share over-frequency governing with thermal units
Next Steps & Ongoing Analysis

- Higher renewable penetration to achieve RPS targets (40% - 60%)
  - Evaluate proposed grid upgrades at higher penetration level

- Incorporate mitigations and grid modernization efforts
  - Energy storage
  - Electric vehicles
  - Fast acting demand response
  - Smart inverters
  - UFLS schemes
  - New operating practices (unit cycling, spinning reserve adjustments, etc.)

- Evaluate other facets of grid stability
  - Transmission faults
  - Grid strength