Hawaiian Electric

IGP Stakeholder Technical Working Group

November 19, 2021

Agenda

- Review 11/5 IGP Grid Needs Assessment Methodology Review Point filing
  - Provide summary of areas where stakeholder feedback was incorporated, not incorporated
- Stakeholder questions regarding EE Supply curves

IGP Grid Needs Assessment Methodology Review Point

- The Grid Needs Assessment Review Point describes the criteria and suite of modeling tools and process used to:
  - Identify near-term quantity and timing of Grid Needs
  - Develop resource plans to solve for near-term needs and long-term objectives
  - Evaluate proposed solutions as part of an RFP to meet Grid Needs
- The Review Point also includes exhibits for:
  - Transmission Renewable Energy Zone Study
  - Location-based Distribution Forecasts
  - Distribution DER Hosting Capacity Grid Needs
  - AEG IGP Supply Curve Memo
  - Redlined updates to Inputs & Assumptions

Energy Efficiency

- Feedback incorporated
  - AEG modified the supply curve data to be stated in $/MW terms instead of $/MWh
  - The supply curve modeling will also use the same $/MW and peak MW impact for consistency
- Feedback not incorporated
  - In the supply curve development, efficiency gains through EE repurchases are not captured
    - EE impacts are assumed to be persistent through the study horizon, consistent with their treatment in RESOLVE
    - Per AEG, efficiency gains based on currently available technology are minimal

Resource Cost Forecasts

- Feedback incorporated
  - Adjustments to PV costs
    - Update Federal ITC for PV to match Database of State Incentives for Renewable & Efficiency[1]
    - Remove State ITC for grid-scale PV to reflect current law[2]
  - Adjustments to offshore wind costs
    - Apply Federal ITC safe harbor through 2035
    - Include EIA location adjustment factor for wind to account for labor and productivity differences
  - Update to 2021 NREL ATB
    - Use cost forecast for Utility-Scale PV-Plus-Battery from ATB directly
  - Remove recent project benchmarking for PV, PV+storage, geothermal and onshore wind based on discussions with Ulupono

[1] https://programs.dsireusa.org/system/program/detail/65
[2] https://www.capitol.hawaii.gov/hrscurrent/Vol04_Ch0201-0257/HRS0235/HRS_0235-0012_0005.htm

Energy Reserve Margin Criteria

- Feedback incorporated
  - Provide justification for the 30% ERM and adopt an ERM target that is tied to a reliability analysis
    - The Company provided its initial analyses to support the proposed ERM targets and follow up reliability analyses in response to Ulupono's feedback to test the ERM target in incremental steps in the 11/5 Grid Needs Assessment Methodology Review Point (Appendix C)
    - The TAP provided feedback that the ERM was sufficiently justified for a first use in the current IGP, provided additional consideration was made for the HDC values and probabilistic RA analysis is done to verify the portfolio at appropriate points
  - Include demand response in the ERM calculation
    - The Company clarified it is including demand response as a resource in its ERM modeling
  - Conduct a probabilistic resource adequacy back check
    - In the Company's proposal for ERM in the first cycle of IGP, a resource adequacy evaluation will be conducted using probabilistic modeling in PLEXOS. This will use calibrated production profiles or simulated production for variable renewables instead of an HDC.

TAP feedback on the ERM criteria was provided in the Company's Response to Information Requests on November 12, 2021 in Docket 2018-0165.

Energy Reserve Margin Criteria

- Feedback not incorporated
  - Include N-1 outage criteria in RESOLVE
    - The Company does impose single point of failure requirements for system security which limits large units from adversely impacting reliability. RESOLVE does not explicitly account for an N-1 outage criteria; however, maintenance and forced outages are accounted for in the PLEXOS modeling.
  - Add ERM sample days with higher than normal loads
    - The TAP did not agree to model the worst weather days in RESOLVE. Reliability should be assessed through the resource adequacy back check using sequential Monte Carlo simulations but not necessarily needed in RESOLVE.
  - Use production profiles instead of HDC for ERM
    - The TAP provided feedback that the HDCs could be further calibrated but the HDC could work for capacity expansion modeling. For the resource adequacy evaluation, the TAP suggested using multiple weather years instead of an HDC.
    - If the Commission is inclined to not adopt the Company's HDCs for the first cycle of IGP, the Company proposed alternative calculations using simulated NREL weather data and expressed in terms of exceedance probability, to be more directly in line with the TAP's recommendations. The Company notes that additional time will be needed to complete this analysis.

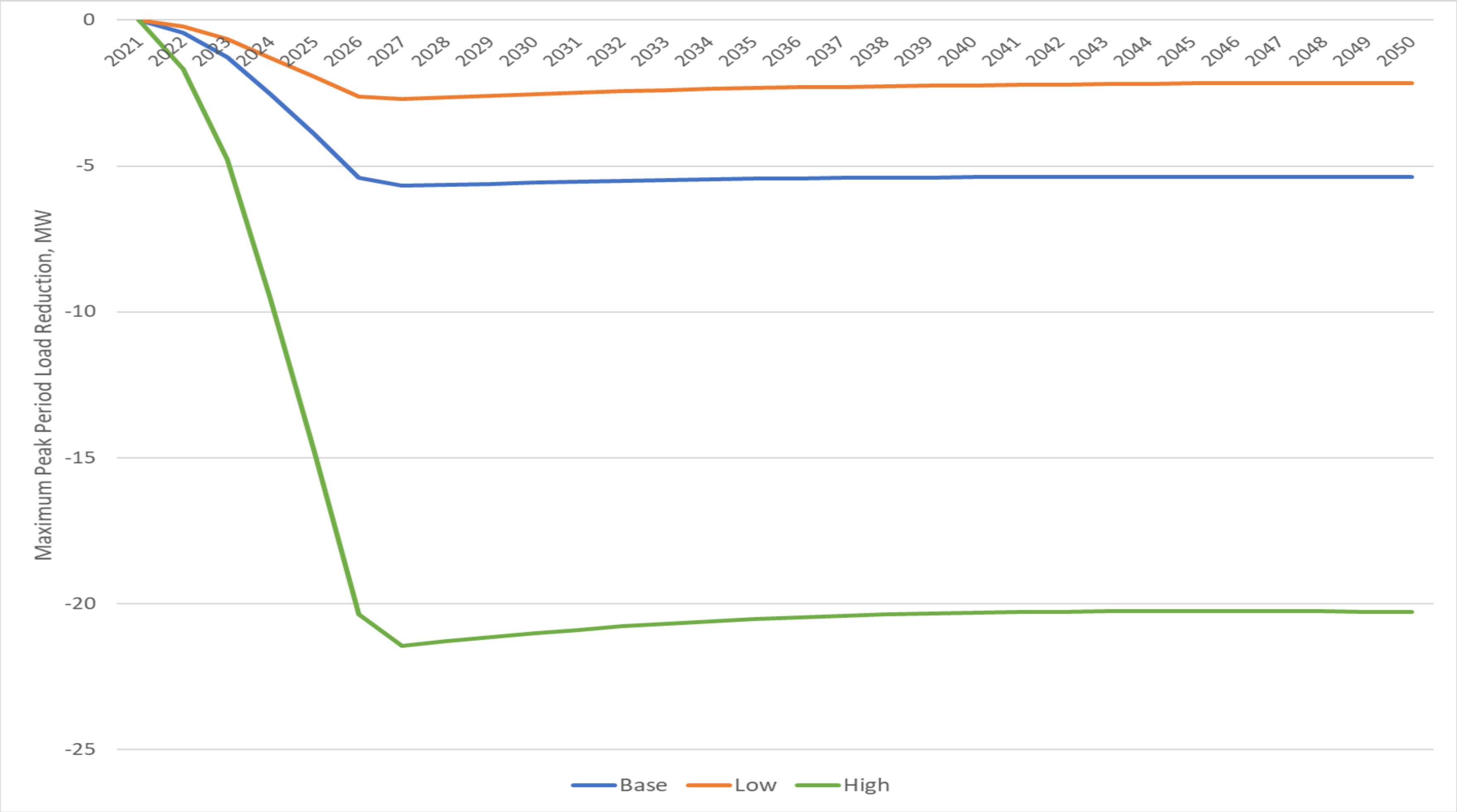
Non-DER Time-of-Use Stakeholder Feedback

- Include residential TOU load shifting in load forecasts
- Use rates from DER Parties' ARD final proposal for residential high TOU scenario
- Review California studies to possibly inform commercial TOU assumptions
- Consumer Advocate comments
    - Consider residential and commercial in the TOU layer
    - Further research is needed for commercial sector
    - Suggested review of three specific mainland studies
    - Suggested review of the Companies' historical commercial TOU customer data
    - Lack of commercial data may suggest value of a pilot
    - Not suggesting the current IGP process be held up or suspended

Non-DER Time-of-Use

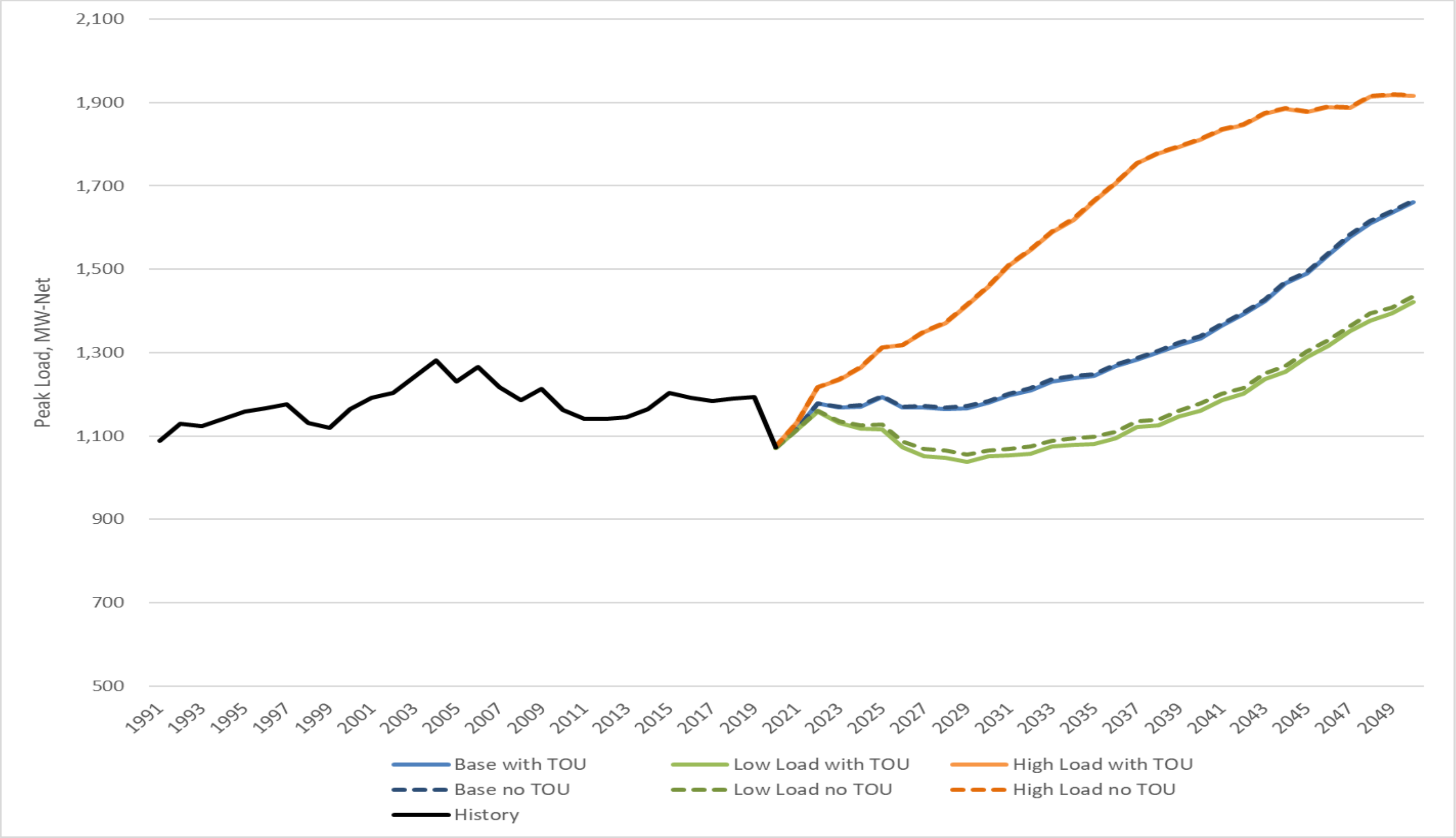
- Residential TOU load shift layer added to all islands and scenarios
- DER Parties' proposed ARD rates used for the high TOU scenario
- Commercial TOU load shift layer not included in this IGP cycle
  - Historically very low participation
  - Literature review did not produce support needed to develop this layer
  - Company will evaluate commercial customers' data as ARD TOU is rolled out following approval
  - Company will review demand response opportunities to complement enablement of commercial load flexibility

Oahu Non-DER Time-of-Use Max Peak-Period Impacts



Maximum potential peak period impact, not coincident with annual system peak

Oahu Non-DER Time-of-Use Peak Impacts



Renewable Energy Zones (GNA Book 2 of 2 – Exhibit 2)

- Appendix B – TAP Feedback
- Appendix C – Stakeholder Feedback/Questions and Responses by Hawaiian Electric
- Oct. 6 Meeting Minutes: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20211006_stwg_meeting_notes.pdf
- Major Revisions (from Oct. 1 draft)
  - Oahu
    - Adding 300MW to Group 8 (Wahiawa) did not require Transmission Network Expansion
    - Adding 400MW Off-Shore Wind at Ko`olau was found to be feasible and did not require additional Transmission Network Expansion
  - All Islands – Added incremental REZ Enablement costs
    - Tables in Sec. 5.4.8 (Oahu), 6.4.3 (Maui), 7.4.3 (Hawaii Island) include varying levels of MW potential by Group.
- Future Revisions
  - Incorporate Resilience Scenarios
  - Transient Stability Analyses
  - Hawaiian Electric to solicit stakeholder and community input to iterate study

Renewable Energy Zones
Least-Cost REZ Enablements (Oahu Example)

	Total Potential			Lowest Cost/MW		
Group	MW	Cost ($MM)	Cost ($MM)/MW	MW	Cost ($MM)	Cost ($MM)/MW
1	120	24.6	0.21	120	24.6	0.21
2	324	87.6	0.27	270	47.1	0.17
3	588	773.9	1.32	270	185.3	0.69
4	331	272.2	0.82	135	58.2	0.43
5	608	916.7	1.51	135	109.4	0.81
6	147	91.2	0.62	147	91.2	0.62
7	66	N/A	N/A	66	N/A	N/A
8	1166	1,460.7	1.25	270	250.6	0.93
Total	**3,350**	**3,626.9**	**1.08**	**1,413**	**766.4**	**0.54**

Location-Based Distribution Forecasts (GNA Book 2 of 2 – Exhibit 3)

- Clarifications Provided
  - Appendix B
  - Oct. 6 Meeting Minutes: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20211006_stwg_meeting_notes.pdf
- Major Revisions (from Oct. 1 draft)
  - Appendix A – Provides links to Workbooks
  - https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/key-stakeholder-documents

Table 1-1: Forecast Layer Mapping of Modeling Scenarios and Sensitivities

No.	Modeling Case	DER Forecast	EV Forecast	EE Forecast	TOU Load Shape
1	Base	Base Forecast	Base Forecast	Base Forecast	Managed EV Charging
2	High Load Customer Technology Adoption Bookend	Low Forecast	High Forecast	Low Forecast	Unmanaged EV Charging
3	Low Load Customer Technology Adoption Bookend	High Forecast	Low Forecast	High Forecast	Managed EV Charging

Distribution Hosting Capacity (GNA Book 2 of 2 – Exhibit 4)

- Clarifications Provided
  - Appendix B
  - Oct. 6 Meeting Minutes: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20211006_stwg_meeting_notes.pdf
- Results

Scenario	# Ckts HC > Forecast	# Ckts Updated HC > Forecast	# Ckts LTC Setting Changes	Solution Required	
				# Ckts	Cost
High	435	92	60	33	$10.7M
Base	509	58	37	16	$5.6M
Low	517	53	35	15	$5.5M

Transmission Planning Criteria (GNA Book 1 of 2 – Exhibit 1, Appendix F)

- TAP Feedback documented in App. K, Sec. 2
- Feedback Incorporated
  - Clarify inertia and frequency response to include IBR response
  - Clarify studies will analyze “expected aggregate loss of DER” instead of “any aggregate loss of DER”
  - Clarify studies will analyze “credible contingencies” instead of just “loss of largest generating unit”
  - Clarify studies review scenarios beyond the basic four scenarios.
- Feedback Not Incorporated (Further future work with TAP req’d)
  - Duration of emergency conductor rating
  - Probabilistic Transmission Planning
  - Potential loss of DER on ROCOF and potential momentary cessation of DERs

System Security Methodology (GNA Book 1 of 2 – Exhibit 1, Sec. 3.3.1)

- TAP Feedback documented in App. K, Sec. 3
- Feedback Incorporated
  - Recommend running PSSE and EMT (e.g., PSCAD) models
  - Prioritize critical cases to run in PSCAD
- Feedback Not Incorporated (Further future work with TAP req'd)
  - Alternative suggestions to using prodsim dispatch information
  - Alternative Grid-Following models
  - Consideration of protection setting changes in high IBR scenarios

Distribution Planning Methodology (GNA Book 1 of 2 – Exhibit 1, Appendix I)

- TAP Feedback documented in App. K, Sec. 4.
- Feedback Incorporated
  - Added more detail and descriptions to solution stage
  - Various clarifications on processes and tools used
- Feedback Not Incorporated (Future)
  - Inclusion of Protection-related requirements

NWA Opportunity Methodology (GNA Book 1 of 2 – Exhibit 1, Appendix J)

- TAP Feedback documented in App. K, Sec. 5.
- Feedback Incorporated
  - Various clarifications on processes and tools used
- Feedback Not Incorporated (Future)
  - Outline of evaluating procurements, programs, and pricing
  - Defining/quantifying forecast certainty (vs. qualitative evaluation)
  - Inclusion of Protection-related requirements

Follow-up discussion on EE Supply Curves

Q&A

Next Steps

- Continued discussions with TAP on how accreditation of renewables will be treated
- Approval of I&A and GNA Review Points so that the Grid Needs Assessment can start

Supplemental Slides

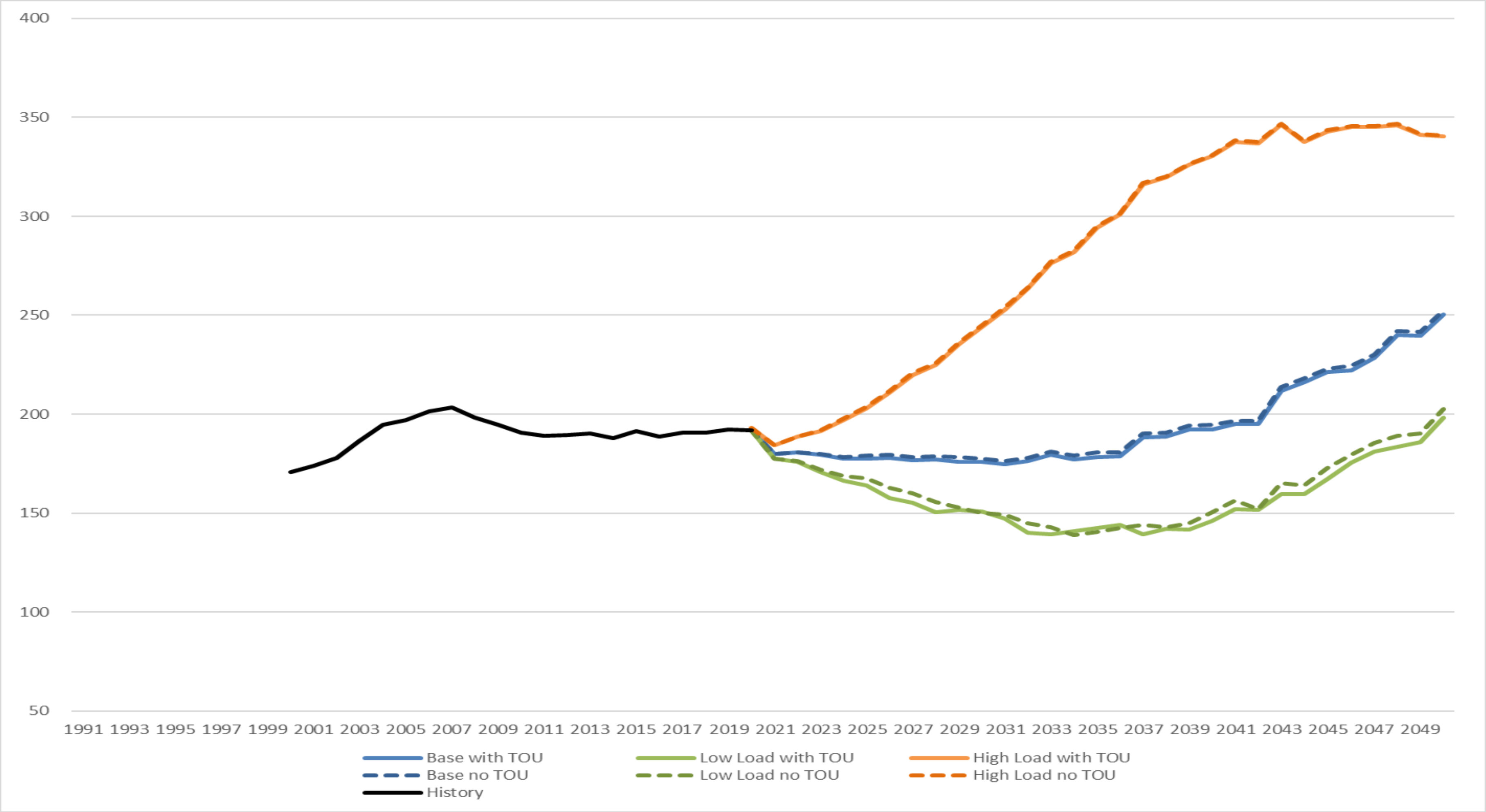
Non-DER Time-of-Use Assumptions

Input	Low	Base	High
Rates	Hawaiian Electric Final ARD Proposal	Hawaiian Electric Final ARD Proposal	DER Parties Final ARD Proposal
Residential Customer Pool	All Non-DER Residential Customers = Residential Forecast Minus High DER Sch-R Forecast	All Non-DER Residential Customers = Residential Forecast Minus Base DER Sch-R Forecast	All Non-DER Residential Customers = Residential Forecast Minus Base DER Sch-R Forecast
AMI Rollout	100% by 2025, Straight line from current deployment to 2025	100% by 2025, Straight line from current deployment to 2025	100% by 2025, Straight line from current deployment to 2025
TOU Rollout	Default rate for AMI meters ramps up from 2022 to 2026	Default rate for AMI meters ramps up from 2022 to 2026	Default rate for AMI meters ramps up from 2022 to 2026
Load Shift Method	Net Zero Load Shift	Net Zero Load Shift	Net Zero Load Shift
TOU Opt-Out Rate [%]	25%	10%	10%
Price Elasticity	-0.045	-0.070	-0.070

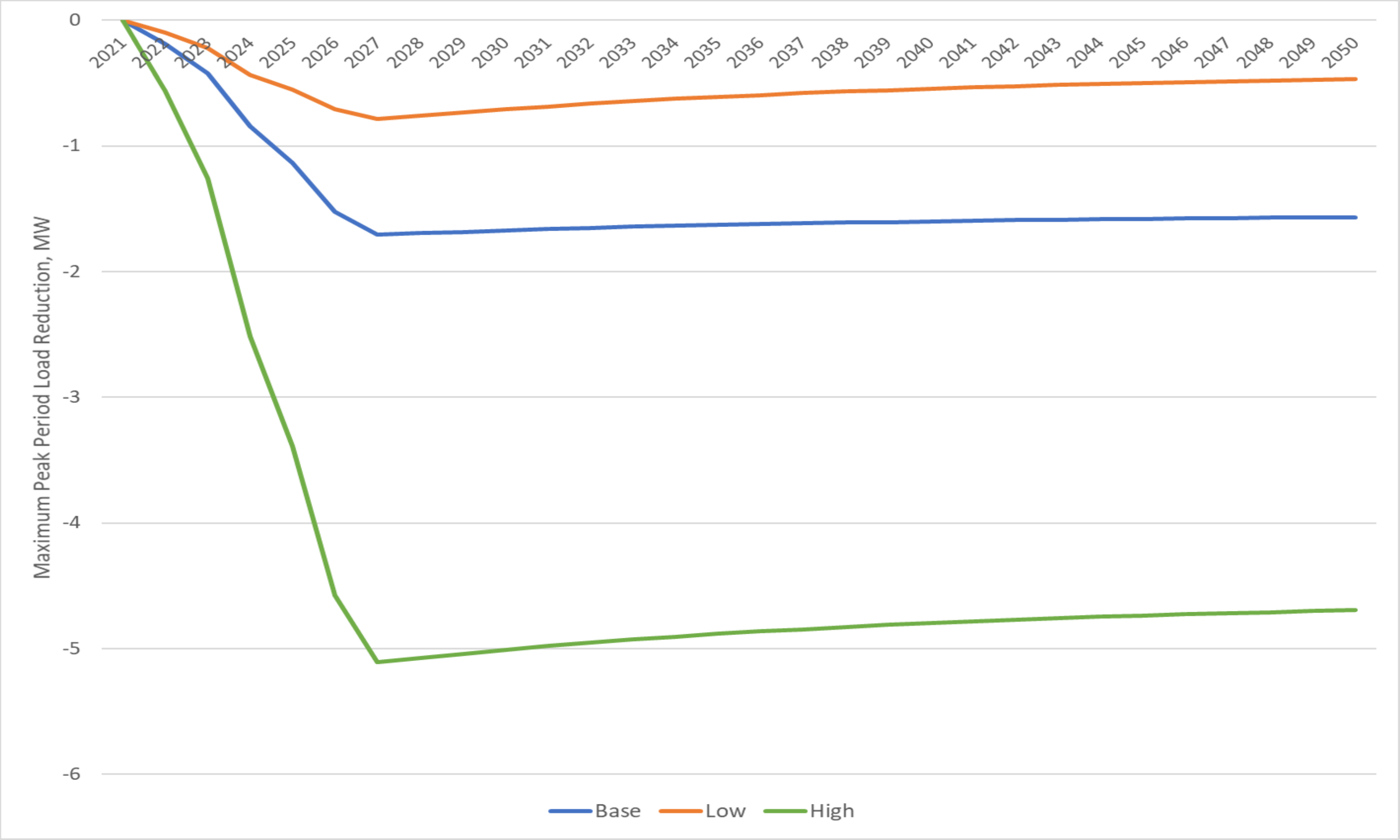
Hawaii Island Non-DER Time-of-Use Peak Impacts

Maximum potential peak period impact, not coincident with annual system peak

Hawaii Island Non-DER Time-of-Use Peak Impacts



Maui Non-DER Time-of-Use Peak Impacts



Maximum potential peak period impact, not coincident with annual system peak

Maui Non-DER Time-of-Use Peak Impacts