IGP Stakeholder Technical Working Group Meeting

Friday, November 19, 2021
12:00pm – 1:30pm
WebEx

Attendees

WebEx

Abel Siu Ho, HE
Alyssa Nada, HE
Anne Fuller, HE
Blaine Hironaga, HE
Brian Lam, HE
Bryant Komo, HE
Christopher Kinoshita, HE
Christopher Lau, HE
Christopher Yunker, HSEO
Clarice Schafer, HPUC
Collin Au, HE
David Parsons, HPUC
Dean Nishina, DCA
Eli Morris, AEG
Grace Relf, HPUC
Henry Curtis, LOL
Jennifer Baker, HE
Jennifer Barnes, 2050 Partners
Jeremy Laundergan, EnerNex
Jerry Sumida, Carlsmith Ball
Jeslyn Kawabata, HE
Jessie Cuilla, RMI
Ken Aramaki, HE
Ken Walter, AEG
Kent Kurashima, HE
Kolter Kalberg, HE
Kylie Cruz, Earthjustice
Li Yu, HE
Lisa Dangelmaier, HE
Mac Wodicker, ASU
Marc Asano, HE
Marcey Chang, DCA
Mathew McNeff, HE
Meredith Chee, HE
Michael Schwing, HSEO
Paul de Martini, Newport Consulting
Pete Polonsky, HPUC
Rene Kamita, DCA
Riley Saito, COH
Robert Uyeunten, HE
Rod Aoki
Samantha Ruiz, Ulupono
Sherilyn Hayashida, DCA
Shuk Han Chan, HE
Stephen Mariani, HPUC
Terry Surles, HNEI
Therese Klaty, HE
Wren Wescoatt, PHOW

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

Discussion

<u>Non-DER TOU</u>

I. Stakeholder: Is the Company assuming no TOU for non-DER commercial customers?
   a. HE: Yes, not including it as a separate layer since we don't have a way to estimate it. In the high load bookend, it would be a low TOU case and the impact will be minimal.
      i. Stakeholder: Understand that it's difficult given the limited uptake to date from TOU though that may be due to current program design.

II. Stakeholder: When telecom companies did TOU starting decades ago, they used a far wider spread in rates.

III. Stakeholder: Assuming zero non DER commercial TOU uptake is missing an opportunity to make an estimate, may need further consideration for the bookends.
   a. HE: Many of the commercial loads peak during the day. For those that peak in the evening like hotels, there's not much theycan do because in the service industry, hotel occupants want to use the facilities at any time. There is a potential there but the customer's use is tied to the type of experience they want and won't necessarily shift their usage. It isn't that commercial load shifting is excluded from the IGP analysis. Commercial non-DER TOU load shifting isn't included as a load forecast modifier. But when we have results of the Grid Needs Assessment, we will look at the potential identified in the demand response potential study to see if there is opportunity to use commercial load resources to meet the grid needs. And if there are grid needs that are new, then we will look at updating the DR potential study to look for opportunity to meet those needs. To realize commercial load shift potential, it will likely take a thoughtful programmatic approach. We will also analyze data as ARD TOU rates are implemented after approval to inform the next IGP cycle.

IV. Stakeholder: Understand the challenges of strategies to shift the load.
   a. HE: On the residential side, we have included TOU load shifting because the SMUD study provided clear support for residential opt-out TOU impacts. There isn't similar support on the commercial side from studies or experience with our customers.

<u>Renewable Energy Zones</u>

V. HE: We included feedback from stakeholders and TAP on REZ. There were questions on cost estimates and assumptions, so we provided those in Appendix B and C of the REZ study. We also included the meeting minutes when the REZ was presented and stated which feedback was incorporated from those meetings.
   a. HE: Revision from October 1st draft, for Oahu, we clarified in report that adding 300MW to Group 8 would not require transmission expansion and looked at 400 MW of Offshore Wind connected at Koolau. Also, in the latest report, we added incremental REZ enablement cost.
   b. HE: Future revisions would consider resiliency scenarios, transient stability analysis, and community and stakeholder input.

VI. HE: In the Grid Needs Assessment we also filed the Location-Based Distribution Forecast. The feedback we got was primarily along the lines of clarifications, which we made in our latest filing. The major revisions from the October 1st filing were providing links to the workbooks, which are available on the websites. The next steps would be to do contingency analyses on the various forecast and developing grid needs.
   a. HE: Distribution Hosting Capacity is the analysis that was done to determine what the grid needs are to accommodate the DER forecast. The feedback we got was primarily along the lines of clarifications, which we made in our latest filing.

VII. HE: We met with the TAP on our Transmission Planning Criteria and System Security Methodology. These are still a work in progress and will continue to evolve. We incorporated things that we came to agreement with the TAP on, but we will continue to have discussions with the TAP on these two subjects and iterate on them in the future.
   a. HE: With regards to the Transmission Planning Criteria, the next things we want to discuss with the TAP is the duration of emergency conductor ratings , look at probabilistic transmission planning methods, and potential loss of DER on ROCOF and momentary cessation of DER.
   b. HE: With regards to the System Security Analysis, what we agreed to with the TAP is we will run cases in PSSE, which is less time-intensive. Based on the results of the PSSE analysis, we will prioritize the critical cases and run them through PSCAD if needed.
   c. HE: Few things that we are still in discussions with the TAP on regarding System Security were alternative suggestions to using prodsim dispatch information, which grid-following model to use, and how to incorporate protection setting changes in high IBR scenarios.

VIII. HE: For both the Distribution Planning Methodology and the NWA Opportunity Methodology, we still need to work on inclusion of protection related requirements in the planning process. For NWA specifically, we need to still think through how we evaluate programs versus procurements versus pricing as NWAs are developed as well as how to quantify the forecast uncertainty.

IX. Stakeholder: Can you talk about the feedback that was not incorporated into the Transmission Planning Criteria and what the thought process is?

a. HE: While conductors have emergency ratings, what hasn't been addressed is how long certain conductors can remain at that emergency rating.
b. HE: For probabilistic transmission planning, considerations for the nature of the variable renewable resource. Currently, we are using a deterministic approach where we get the prodsim data and use that as a snapshot to do our stability analysis. The TAP, however, suggested that we probably should look at a larger range of simulations and use a probabilistic approach to factor uncertainty. This is different from what we are doing now, so we need more time to develop this type of planning methodology.

X. HE: Regarding the potential momentary cessation of DERs, in the Stage 2 study, once the transmission level has a fault, system voltage can go very low, and if that voltage is lower than the momentary cessation of DER undervoltage limit, DER will be in momentary cessation. Once fault is cleared, DER will still be in momentary cessation until the voltage is higher than the undervoltage limit, which will cause issues because the loss of DER generation may cause the frequency to drop and result in UFLS.

XI. HE: Regarding the potential loss of DER on ROCOF (Rate of Change of Frequency), some DER use that as an anti-islanding detection method. Since we are shifting to inverter-based generation, the system is losing inertia, which means the ROCOF could be faster than before. As a result, a potential issue could be DER may see faster frequency change as a signal of unintended islanding happening, which may cause it to trip.

XII. Stakeholder: With regards to the potential momentary cessation of DERs, is the Company planning on doing any follow-up work to address this issue? If it will not be addressed in this round on IGP, is there any intent to do some work to see what would be future actions that are needed?
a. HE: In current ongoing stability study, we will run different momentary cessation limits to evaluate this issue in more detail. We are also working with NREL and looking at past inverter testing data to get a clearer understanding of the inverters and the more appropriate assumptions to use in our study. We will continue to look into this after this round of IGP. We will also look closer at the ROCOF issue but are not planning on addressing this issue in this round of IGP.
b. HE: We will not be able to change how the actual rooftop inverters behave, and it's probably not something that can be addressed in the near-term based on the current state of the inverters, but from a modeling perspective, we are trying to assess what the risk is that we are trying to mitigate.

XIII. SH: Understood. If we are not looking at this for IGP, just wondering how this may affect the results and if there is anything we should be thinking about when looking at the results. If it's not something that is taken into account in this IGP, then that's fine, but if there is something that is happening that is fed back into the resource plans, then please explain it.
a. HE: We will keep that in mind. One issue is the inverter manufacturers can vary in how they detect ROCOF and how they use that in their protection control.

Energy Efficiency Supply Curves

XIV. Stakeholder: Can you speak on the Net to Gross ratios?

a. HE: Gross is all program participants and all incentivized measures. Net is incentivized measures that were implemented because of the incentive. The net to gross ratio is used to remove free ridership from the data received from Hawaiʻi Energy to derive the acquired EE. Free ridership is defined as customers who implemented an EE measure and are happy to take the incentive because it's there but would have done it regardless of the incentive. We modeled the free ridership as part of the underlying sales and load. We remove free ridership from the future EE so that we have consistent treatment of free ridership in the acquired and future EE and avoid double counting.

XV. HE: The underlying load shapes are from historical measured data, and the acquired EE measures are reflected in the historical shapes. For the sales forecast, we take the historical EE measures that are already implemented and decrement the underlying sales by that amount and put that into the underlying hourly load shape. AEG provided hourly shapes for future EE only from the MPS. So both acquired and future EE is accounted for in the load and not double counted. Naturally occurring is fully embedded in the underlying.

XVI. Stakeholder: We were looking at the supply curves and were confused about the Other vs Peak bundles. We were wondering if AEG considered doing a more granular cost-based bundle in the range that's right above where the average cost would be.

a. AEG: The concern with cost per energy savings is that you don't gain visibility about when savings occur. If you combined measures that had flat profiles versus measures that don't have a flat profile, you lose insight into when the benefits occur and any targeted benefit that the grid may need.

b. HE: Since the potential study already looked at the B/C ratio, we wanted to validate the set of measures that the potential study found to be cost effective to see if that was still cost effective in IGP. We also wanted to separate out the measures that had a peak impact versus measures that had a flatter impact because the potential study found that certain measures were cost effective because they provided greater impact during the peak period and we wanted to confirm this still occurs in IGP.

XVII. Stakeholder: Is the technical achievable potential less than the economic potential?

a. AEG: For an individual measure, technical potential could be less because it's competing with other end uses whereas the economic may have already screened out those other competing uses.

XVIII. Stakeholder: Is the savings only for one year?

a. AEG: The summary files have savings through the study period. The unitized hourly profile is only one year but would scale against the cumulative capacity.

<u>Energy Reserve Margin</u>

I. Stakeholder: Is the proposal to run a range of ERM and HDC or move forward with one option?

a. HE: Based on our own analysis and HNEI/TAP's analysis, using the proposed ERM to create resource plans and then testing them in PLEXOS is appropriate. At the backcheck step in PLEXOS, if there are significant reliability shortfalls, we can iterate the resource plan.

b. HE: We felt 1 sigma and 2 sigma for wind and pv were appropriate. The TAP suggested using a 30 day window on historical data. We are looking at that alternative to determining HDC. Other members of TAP preferred to use the production profile. Another alternative is to use the NREL simulated data but we would need to compare that to historical data. Simulated data may be over estimating production from wind and solar when compared to what's seen historically.
    i. Stakeholder: Is this for PLEXOS or RESOLVE?
        1. HE: This is just for HDCs in RESOLVE. For PLEXOS, we are in agreement with TAP to use an approach similar to TELOS.
    ii. Stakeholder: What is the feedback from stakeholders? What is the timeline for updated recommendation?
        1. HE: We met with the TAP earlier this week and they are cleaning up notes/recommendations.
        2. Stakeholder: Given the GNA is planned to precede the next Oahu/Maui procurement, which already won't occur until 2023, it is important that HECO get started on the grid assessment as soon as possible. While we can continue to discuss inputs forever, stakeholders need to give them the green light to get started, or the next RFP will continue to be pushed out.

Next Steps

- Stakeholders may provide feedback on today's discussion to igp@hawaiianelectric.com.