HECO IGP Technical Advisory Panel
Summary and Feedback from July 2022 Meeting Related to PUC Order on Grid Needs Assessment
7/8/2022

This feedback and summary was delivered by the IGP Technical Advisory Panel (TAP) to Hawaiian Electric (HECO) based on HECO's slides and presentation at the full TAP meeting on July 7, 2022. It relates to the PUC order released the prior week on the Grid Needs Assessment.

TAP members present:

- Andy Hoke (NREL, Chair)
- Aidan Tuohy (EPRI, Vice-Chair)
- Matthias Fripp (UH)
- Elaine Hale (NREL)
- Debbie Lew (ESIG)
- Jo Ann Ranola (EPRI)
- Matt Richwine (Telos)
- Derek Stenclik (Telos)
- Gord Stephen (NREL/UW)

HECO participants:

- Marc Asano
- Ken Aramaki
- Collin Au
- Lisa Dangelmaier
- Riley Fukuji
- Chris Kinoshita
- Janelle Kau
- Brian Lam
- Chris Lau
- Isaac Lum
- Chris Ono
- Dean Oshiro
- Li Yu

TAP feedback and comments are divided into three categories:

1. Informational
2. Action recommended prior to August GNA deadline
3. Action recommended after August GNA deadline

Summary of TAP Feedback

Regarding the order to use ELCC: While ELCC is widely recommended today, resource adequacy experts in California and on the TAP are starting to move away from it for very high renewable scenarios, and the TAP does not see it as the obvious best choice. The TAP believes that further evaluation of capacity accreditation options is warranted before committing to use ELCC.

ELCC calculations are very time-consuming and nuanced. Decisions on average versus marginal ELCC and how to best represent both saturation effects and portfolio effects need to be considered. Heuristic approaches may give a similar, representative answer in much less time. In addition, the TAP recommends testing various bookend capacity credits in RESOLVE to understand how sensitive the model results are to this assumption.

The TAP suggests that rather than committing to ELCC, ELCC should be compared to other approaches (mentioned below) by running selected simulations and comparing costs, resource mixes, and time to produce result. Based on that comparison, the approach that produces the least-cost adequate mix should be used (subject to a system-level minimum reliability standard / maximum risk metric such as LOLE, NEUE, etc). If two or more approaches result in resource costs that differ by an amount smaller than the uncertainties in those cost estimates, the more time-efficient approach can be selected.

Regarding iterations between GNA and system security: The TAP feels it should be possible to define a set of possible mitigation methods and the likely degrees of iteration that each method would require before the August GNA filing deadline. The TAP can help with this.

Regarding re-incorporation of inertia- and FFR-related criteria in the GNA: The TAP believes it should be possible to incorporate new constraints into the capacity planning and resource scheduling steps of the GNA that approximately capture the ability of each type of resource to provide emerging grid security-related services such as inertia, inertia-like services, and FFR. There is currently no consensus on exactly what those services should be, how to approximately quantify the ability of different resource types to provide those services, or how to determine the minimum threshold of each service needed for grid security. However, incorporation of approximate thresholds for services with approximate capabilities assigned to different resource types will probably increase the likelihood that the GNA selects a resource mix and dispatch scenarios that meet system security needs, thereby hopefully reducing the need for iterations of the GNA. That said, it has not been proven that such an approach is superior to one that omits system security-based constraints from capacity planning and production cost models, or to other approaches to incorporating system security into capacity planning and resource adequacy, so the GNA should be permitted to try various approaches rather than tying it to one single approach (e.g. virtual inertia and FFR). The TAP can work with HECO to suggest and evaluate different services similar virtual inertia and FFR for use in the GNA. The TAP will be happy to discuss this further with HECO.

Detailed Notes

Note's from the discussion are presented below along with some of HECO's slides for context.

HECO: summary of PUC order:

Recent Commission Orders Issued June 30, 2022

- Stage 3 RFP Order
  - File a Near-term Grid Needs Assessment for O'ahu and Maui within 30 days (July 29) and host a technical conference to discuss
- IGP Order
  - Approves the November 2021 Grid Needs Assessment Methodology Filing with modifications to the energy reserve margin and capacity accreditation with additional clarification, guidance on other issues
  - Approves ERM and exceedance-based HDC for this round of IGP only. Use of ERM/HDC outside of IGP requires PUC approval, and not for use in any other docket or filing (i.e., AOS, KPP transition plans).
  - Agrees with approach to add probabilistic analysis IGP process, including 250 draws and calculation of LOLP, LOLE, LOLH, and EUE. Future iterations should integrate climate change into its weather modeling.
  - Instructs Hawaiian Electric to develop an ELCC-based resource adequacy criteria for use in future rounds of IGP and develop a workplan in consultation with the TAP and Parties. The workplan must explain:
    - How Hawaiian Electric intends to solicit and incorporate stakeholder feedback
    - How long Hawaiian Electric expects the process to take
    - How and in what dockets and other efforts Hawaiian Electric uses ERM and HDC as resource adequacy criteria
    - How Hawaiian Electric could begin transitioning from using ERM and HDC to ELCC in IGP and elsewhere
    - How long it would take to compute ELCC for all resource types evaluated in PLEXOS as part of Hawaiian Electric's stochastic reliability modeling in the current round of IGP
    - File this workplan by August 31, 2022
  - Directs Hawaiian Electric to communicate to the Commission and stakeholders when the TAP's recommendations for future IGP processes will be implemented, file future written recommendations and advice from the TAP, as they are received, in this docket.

IGP Order: Impact of System Security Analysis on Resource Plans

- Hawaiian Electric's practical approach to adjusting the resource plan for transmission planning criteria violations remains unclear.
- The Commission shares Ulupono's concerns regarding the proper use of the optimization models in the grid needs assessment process. More explanation is needed for the magnitude of violations that would trigger an iteration in the prior modeling steps and how an addition or adjustment to the resource plan or production simulation would be sized appropriately to meet the violation.
- Commission directs Hawaiian Electric to clarify the magnitude and number of violations that would trigger a model iteration for another step in the GNA process. Must also clarify how it will use the modeling tools to continue to optimize the resource plan after an iteration. Provide written explanation in the Final GNA methodology.
- Directs Hawaiian Electric to promptly communicate with the Commission and stakeholders when modeling iterations occur as a result of not meeting certain criteria from any modeling step. At a minimum, this communication must include an IGP working group meeting open to all stakeholders, such as the STWG, and be filed in writing in this docket and posted on the IGP website.
- The Commission directs Hawaiian Electric to prepare methods to reincorporate virtual inertia and fast frequency response in the optimization tool used to develop resource plans in future iterations of IGP.

- IGP Order: Regulating Reserve Criteria

  - Commission is satisfied with the clarity regarding the methods used to determine regulating reserve requirements. However, Hawaiian Electric must better justify the standard deviation approach it will use to determine the regulating reserves for each island.
  - Hawaiian Electric has not yet responded to stakeholder feedback regarding the decision to use three standard deviations.
  - The Commission further directs Hawaiian Electric to conduct the additional analysis of the regulating reserve requirements recommended by Ulupono to arrive at the desired percentile for calculating regulating reserves instead of the 3-sigma calculation and use this result to implement "the best combination of high reliability and low reserve requirements" in the next round of IGP.
  - Directs Hawaiian Electric to continue its review of this framework with stakeholders and the TAP to determine if there is a need to cap regulating reserve requirements in future rounds of IGP.

- IGP Order: Transmission REZ Study

  - Commission is concerned about the accuracy of these costs and implications on the model outcomes. To address these concerns, the Commission directs Hawaiian Electric to test the sensitivity of the transmission costs inputs in RESOLVE resulting from the REZ study.
  - Further improvements that Hawaiian Electric must make to future iterations of the REZ study include: (1) following the TAP's recommendations to incorporate behind-the-meter DERs; (2) creating stepwise supply curves for each group; (3) incorporating non-Transmission alternatives; and (4) conducting additional transmission studies.
  - Commission also directs Hawaiian Electric to consider the TAP's recommendation to use a chronological modeling tool, such as PLEXOS, to perform the dispatch analysis necessary to evaluate real-life scenarios and estimate transmission-related costs more accurately in future iterations of the REZ study.
  - Hawaiian Electric must propose a community engagement plan for REZ development. This plan should clearly define how results from community engagement will inform REZ constraints and how these constraints will modify the results of the study. This plan will require Hawaiian Electric to clearly present technical information in a way that all stakeholders can easily comprehend, as discussed throughout this order. The Commission will monitor this process as it progresses before approving the results.

  - HECO: Currently no transmission nodes built in PLEXOS

Discussion on ELCC and alternatives

- Discussion

  - ERM/HDC vs. PRM/ELCC in capacity expansion; probabilistic in PLEXOS
    - Given the thorough probabilistic analysis conducted, will the change to PRM/ELCC significantly impact results?
    - Calibrating ERM did not impact resource mix or lead to less build of hybrid solar; however, the firm generation amount did vary
    - Appropriate type analysis for adequacy of supply or other reliability assessments?

  - HECO: Since we don't have a market, do we expect benefit of ELCC will outweigh time cost, given we are already doing probabilistic RA?
  - TAP member: Probabilistic RA gives enough confidence in adequacy. ERM approach is a step forward relative to ELCC if HDC can be replaced with an more equitable approach. ELCC will take a lot longer, probably need to find a faster tool than PLEXOS, or use heuristic.
    - HECO: Resource mix selected by RESOLVE is not very sensitive to inputs. It always selects lots of PV+BESS
    - TAP member (via email): See attached for a slide deck I presented at the NERC Probabilistic Assessment Forum last fall that discusses ERM vs PRM (some familiar faces in the examples at

the end… and this was before I had joined the TAP!). What I refer to there as time-varying UCAP for thermal units is equivalent to what another TAP member is calling hourly expected capacity.

    - NREL report comparing multiple different capacity credit heuristics with EFC (particularly section 4) https://www.nrel.gov/docs/fy21osti/80486.pdf .
    - NREL report comparing EFC with the capacity credit heuristic used with PRMs in RPM (ReEDS, another NREL tool, uses a similar approximation, although with fewer peak net load hours): https://www.nrel.gov/docs/fy21osti/72472.pdf
    - Anecdotally, in RPM (NREL tool) we've seen storage capacity credit approximations stop working well at higher levels of renewables (forcing us to compensate by cranking up the PRM to get adequate systems), which is one reason I'm such a proponent of using ERM instead. I don't think we've published anything about that though.
    - Those reports both focus on EFC, not ELCC, but since you're not modeling transmission constraints (I think?) I would expect the two metrics to be more or less equivalent.
    - I'm in the middle of some work looking at the model runtime implications and cost reduction benefits of ERM (using expected capacities and dynamic risk period selection) vs PRM and capacity credits, but unfortunately I don't have any numbers I can share yet. I should have results to share in the next month or two.

- TAP member: Agree with the previous TAP member's general summary. Ex-post probabilistic analysis (i.e. after the portfolio selection) is the most important way to check adequacy of portfolios selected by RESOLVE. However, RESOLVE needs to be seeded with a firm capacity credit by resource and a reliability target.
  - ELCC is very time consuming. ERM + HDC heuristic can give very close to same answer with much less time.
  - Agree with HECO that the model will not be sensitive to this assumption for what renewables get built. However, it will be a very important assumption determining how much capacity can be retired and the contribution of storage. But there are other ways to determine how much storage is needed (i.e. probabilistic analysis) given certain levels of retirements. Recommend developing a thermal unit retirement plan.
  - Summary of work going on on this topic:
    - I am leaning towards an average contribution during peak risk periods (ESIG example – HECO has; not public yet; cite with "Telos Energy / ESIG Redefining Resource Adequacy Task Force" or something similar)
    - California Slice of Day: Nick Pappas has a good summary of the CPUC RA Proposals.
    - NYISO (GE) is proposing a Marginal Reliability Improvement (MRI)
    - MISO is proposing a blended evaluation of past and future contributions during risk periods.
    - See attachments
- TAP member: Which docket are we talking about?
  - HECO: PUC made clear request for ELCC is for future work, not near-term GNA.
  - TAP member: Agree that it can be hard to calculate ELCC. A simplified approach can have merit. For example, reporting the average output from each resource class during shortfall hours would give a direct estimate of marginal ELCC for each resource. Need iteration between RESOLVE and resource adequacy stage. You know my concerns on ERM and HDC. They can work if using hourly expected capacity for each resource. Not sure what method will work best, but can compare different methods (three approaches) on cost.
  - TAP member suggests **comparing three capacity-forcing approaches**:
    - (From chat)
    - 1. ERM/HDC: pretty much as currently proposed: assign HDC to each resource class as well as possible, then require RESOLVE to choose resources whose HDC adds up to meet load plus ERM in

each hour. Test the capacity plan in a resource adequacy model. If there are too many or too few shortfalls, adjust ERM for that year. Repeat until right adequacy level is achieved.

        - 2. PRM/ELCC: run RESOLVE without the ERM/HDC elements; instead assign a capacity credit (ELCC) to each class of resource each year and a capacity target (PRM) to meet each year. RESOLVE is required to add enough resources to meet the PRM each year. After each RESOLVE run, the portfolio is tested in a resource adequacy model. If there are too many or too few shortfalls in a given year, PRM for that year is adjusted. ELCC for each generator class in each year is calculated in the resource adequacy model, possibly as the average output from that class during shortfall hours in that year. The updated ELCC's and PRMs are put into RESOLVE and it is run again. This should converge eventually to a point where ELCC of each generator class in the resource adequacy study matches the ELCC being used in RESOLVE.
        - 3. ERM/Hourly Expected Capacity (HEC): similar to ERM/HDC, but HDC is replaced with HEC. For intermittent projects, HEC is calculated as the expected availability of each wind/solar project in each hour of each sample day (same as the profiles used for the economic optimization). For thermal plants and storage, HEC is nameplate capacity derated by forced outage rate for that type of generator. Storage would be used to store energy and redeliver at appropriate times. All of this is identical to the main optimization that RESOLVE does (or should do), but it would be dispatched to meet load + ERM instead of just load. Extra care would be taken to include the worst weather days in the sample set, but this may not be essential. Test the capacity plan in a resource adequacy model. If there are too many or too few shortfalls, adjust ERM for that year. Repeat until right adequacy level is achieved. (May need to set ERM separately for each year.)
        - All of these methods iterate between the capacity model and the resource adequacy model, cranking the ERM or PRM up until adequacy is achieved. (They may also propagate some extra information back, e.g., ELCC values). So all of them can provide an adequate plan. So one option would be to try all three and see which gives the best plan (lowest cost for an adequate level of reliability). This also somewhat addresses the PUC's question about when another iteration is needed: they seem to assume each iteration is done to address a failure of the process, but actually iterations are just a built-in part of the process, used to harmonize capacity and adequacy models. And iterations continue until the right level of adequacy is achieved.
        - This is summarized in a slide deck shared via email by this TAP member.
    - TAP member: I'd support approach #3: (ERM + expected capacity) over (PRM+ELCC). The only other improvement I would suggest would be to dynamically add ERM dispatch days based on risk periods identified in the probabilistic RA step from the previous iteration… But as the other TAP member says, even without that you can still force the system to be adequate (just maybe less cost-optimal) with a less strategic choice of periods by just cranking up the ERM instead.
        - Another TAP member agrees, and adds: PRM+ELCC may bias the mix in the opposite direction from ERM+HDC if worst weather days are not included.
    - TAP member: Maybe we do need thermal capacity close to peak load, but want to prove it.
    - HECO: We've tried adjusting capacity credits in RESOLVE. Can share results later
- TAP member: All methods have assumptions. None is perfect, but some may provide more transparency and basis to their assumptions than others. Like the idea of comparing methods if there is time, or at least more detailed thinking through of what the differences are likely to be in RESOLVE outputs.
    - HECO: we will try to find time to compare the three methods
    - Another TAP member: even before that, you can adjust capacity credit given to storage in RESOLVE to see sensitivity
    - HECO: before settling on ELCC, will compare to other methods
- TAP member: What about classifying resources by type of capacity required?
    - Another TAP member: Good idea.
        - To follow-up on the heuristic discussion... MISO is potentially going to switch to a Capacity Credit during tight margin and LOL hours

        - https://www.misoenergy.org/link/23187c720fdd4a33b78e86f355320b26.aspx?epslanguage=en
        - Also looking at other approaches
        - ELCC is current best practice in most regions, but California and Hawaii are moving away from it, so alternatives should be evaluated
    - TAP member: can you elaborate?
        - TAP member: look at hourly unserved energy hours. Look at average output of each resource during loss-of-load hours:

An illustrative example: solar

System Unserved Energy

	Weather Year 1			Weather Year 2		
Hour of Year	Sample 1	Sample 2	Sample N	Sample 1	Sample 2	Sample N
1	0	0	0	10	0	0
2	0	0	0	0	0	0
3	0	0	0	0	0	0
4	20	0	0	0	0	0
5	40	0	0	0	30	0
6	10	0	0	0	10	0
7	0	0	0	0	5	0
8	0	0	0	0	2	0
9	0	0	0	0	1	0
10	0	0	0	0	0	0
...	0	0	6	0	0	0
8758	0	0	10	0	0	0
8759	0	0	2	0	0	0
8760	0	0	0	0	0	0

Two weather years, 6 outage samples
LOLE = 0.67 days/year
LOLH = 2 hours/year
EUE = 24.3 MWh/year

Generator Availability*
(installed capacity = 10 MW)

	Weather Year 1			Weather Year 2		
Hour of Year	Sample 1	Sample 2	Sample N	Sample 1	Sample 2	Sample N
1	0	0	0	0	0	0
2	0	0	0	0	0	0
3	1	1	1	0	0	0
4	4	4	4	2	2	2
5	8	8	8	3	3	3
6	3	3	3	1	1	1
7	1	1	1	0	0	0
8	0	0	0	0	0	0
9	0	0	0	0	0	0
10	1	1	1	2	2	2
...	5	5	5	6	6	6
8758	10	10	10	0	0	0
8759	6	6	6	6	6	6
8760	3	3	3	1	1	1

Average out during events = 3.33 MW
Nameplate Capacity = 10 MW
Capacity Accreditation = 33%

    - TELOS ENERGY www.telos.energy 6
    - TAP member: This approach has lots of assumptions too.
    - TAP member: Agreed. What I like is that you can do this for every class of resource.

Discussion on interation between GNA and security studies

- System Security
    - How to quantify shortfalls?
    - How best to integrate FFR and inertia constraints in a capacity expansion model given grid forming inverters?
    - What is the threshold for RESOLVE iterations e.g. above a certain quantity of firm or synchronous condensers that need to be added? Is it more meaningful to iterate on the PLEXOS production simulation instead of all the way back to RESOLVE?

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    - TAP member: Perhaps we can classify violations into ones that require minor changes vs ones that require a change in resource mix.
    - TAP member: ESIG starting an effort to look at capacity expansion models to improve them for transmission planning users. PSO does N-1 in capacity expansion.

- TAP member: Can capacity expansion tool report on depth/shallowness of resource mix? Can it (e.g. RESOLVE) tell you what axes have high impact on cost vs what axes have no impact on cost? I.e. changes are sensitive. E3 is included in the project.
    - HECO: RESOLVE just gives one plan. Some other tools give multiple options.
- TAP member: On FFR and inertia
    - In RESOLVE-PLEXOS-stability loop, try to just iterate back one level if that can fix the
- HECO: Maybe we can list potential mitigations? TAP member: Yes, and list likely mitigations of each, and what step(s) may be iterated.
    - TAP member: how hard is it to iterate? HECO: Not hard, just takes time.
    - TAP member: Agreed iterates are time-intensive. Industry needs to improve linkages between tools. Important to test resource mixes as you go.
    - TAP member: Can you use different PLEXOS-based tools for multiple steps in process?
    - TAP member: Agree. We are working with Energy Exemplar in linking PLEXOS to PSSE, and in a broader effort (Integrated Strategic System Planning) to link different modeling domains. That is resulting in a number of screening criteria for when to pass info between models and what to pass, as well as tools to screen from PCM->PF and CEM->PCM.
- HECO: How can we capture FFR and inertia needs in RESOLVE?
    - TAP member: Need to understand types of resources and how much stability they give. Can maybe give GFM resources a MW-s value approximation. Create threshold for minimum effect inertia based on highest risk scenarios.
    - TAP member: Agree:
    - TAP member: We have some past work on this.
    - TAP member: Keep inertia separate from FFR.
    - TAP member (in chat, with later clarifications): About inertia, short-circuit current, etc.: Those could probably be handled similarly to the PRM/ELCC approach above. If you find you fall short of these services in the resource adequacy study or system stability study, you could set a target for that service in RESOLVE and assign each resource a credit toward that target based on its performance in the production cost model and the dynamic stability model. (To do this right, you need to include the capabilities of grid-forming inverters, which was the main concern about the previous version of these targets.)
        - TAP member: I'm not aware of a way to verify system stability in a production cost model on the timescales relevant to grid-forming/inertia/short-circuit current. This would likely need to be done in dynamic software (PSSE or, more likely, PSCAD). A production cost model could set a target for each stability service, similar to RESOLVE, which would increase the likelihood of the ProdCost selecting stable/secure dispatches, which would then be verified in PSSE/PSCAD and iterated if needed.
    - TAP member: Can you experimentally define the "effective inertia" or "effective FFR" of a resource based on simulations?
        - TAP member: Maybe. Hopefully can at least approximate. Still need PSSE/PSCAD as final go-no-go.
    - HECO: Won't effective inertia/FFR needs change over time? TAP member: Not necessarily. Could change based on changes in worst-case events.
    - HECO: Re virtual inertia: GFM is very different from sync machines. Vendors will have very different MW-s values. Need to make sure in high-IBR system we have enough voltage-forming sources. May not be ready to do this today.
        - TAP member: Want to see more details of these concerns. There are many voltage support options. HECO: GFM capacity gets taken up by voltage events. TAP member: Power and reactive power are in quadrature. Can get both at the same time to some extent.

        - TAP member: do you require Q at full P? HECO: yes, in steady-state. Stage 3 requires short-term overcurrent capability. TAP member: Short-term overcurrent is possibly yet another category of system need.
        - TAP member: The idea of including a rough approximation of the voltage-forming capacity and other potential stability/security services is to bring the GNA closer to a stable/secure dispatch. This would of course still need to be verified in dynamic software, currently in the EMT domain.
        - TAP member: Voltage-forming capacity may be a better metric/service than inertia or virtual inertia, because it better captures what sync machines and GFM inverter have that GFL inverters don't have. It should probably not be the only metric though. Others could be fast active power response (e.g. FFR) and maybe fault current capacity. More work is needed to determine the best services/metrics need to ensure stability and operability of a high-IBR system.
    - TAP member: Have you tested putting inertia and FFR requirements in the GNA?
        - HECO: The past FFR requirement didn't drive much difference in RESOLVE output. Inertia impacted RESOLVE choices. We only looked at physical inertia at that time.
            - TAP member (later via email): Might be worth checking the ISP methodology in Australia. Their approach may be different, but it's worth reading.
                - AEMO includes power system constraints (e.g., number of large synchronous units online in each region) in the ST model (not LT). LT-ST interaction is shown on page 12 of 2021-isp-methodology.pdf (aemo.com.au).
                - Note that the numbers of large synchronous units online per region AEMO use are high-level planning assumptions (not operational advice). When assessing system strength and inertia shortfalls, the requirement to always keep minimum units online is relaxed in ST in order to determine timing and size of potential shortfalls.
                - The status of all synchronous units (on/off) is extracted from ST output that is applied to the PSSE model to assess system strength and inertia levels. The steps are listed on page 22 and 24 of appendix--9.pdf (aemo.com.au).
        - TAP member: A concern with the previous inertia requirement was that it didn't give credit to GFM.
    - TAP member: Also need to consider PSSE vs PSCAD stability analysis capabilities