IGP TAP Transmission Subgroup

Interim Feedback on System Stability Study

1/31/2022; revised 2/11//2022

This feedback to HECO is based on HECO's slides and presentations on 12/13/2021 and 1/21/2022 related to their in-progress system stability study. New content following the 1/21 meeting is highlighted for ease of identification

As with all TAP feedback, please consider this input as a set of recommendations for consideration – the final choices are yours of course. Some of these topics are complex; the brief feedback included here just points in a direction we think might be helpful.

Several items in this document are intended to help inform additional discussion on this topic.

TAP members attending 12/13: Andy Hoke (NREL, Chair), Debbie Lew (ESIG), Matt Richwine (Telos/HNEI), Terry Surles (HNEI), Aidan Tuohy (EPRI, partially present). Not able to attend: Dana Cabbell (SCE), Deepak Ramasubramanian (EPRI)

TAP members attending 1/21: Andy Hoke (NREL, Chair), Debbie Lew (ESIG), Matt Richwine (Telos/HNEI), Deepak Ramasubramanian (EPRI), Terry Surles (HNEI), Vishal Patel (SCE, first meeting). Not able to attend: Dana Cabbell (SCE)

HECO presenters: Li Yu, Ken Arakawa, Brian Lee, Marc Asano, Chris Lau, Leland Cockcroft

Consultants to HECO: Andrew Isaacs, Lukas Unruh

TAP feedback and comments are divided into three categories:

1. Informational – no action needed.
2. Suggest addressing before March completion of study.
3. Consider feedback for future studies or other portions of the IGP process (after this study).

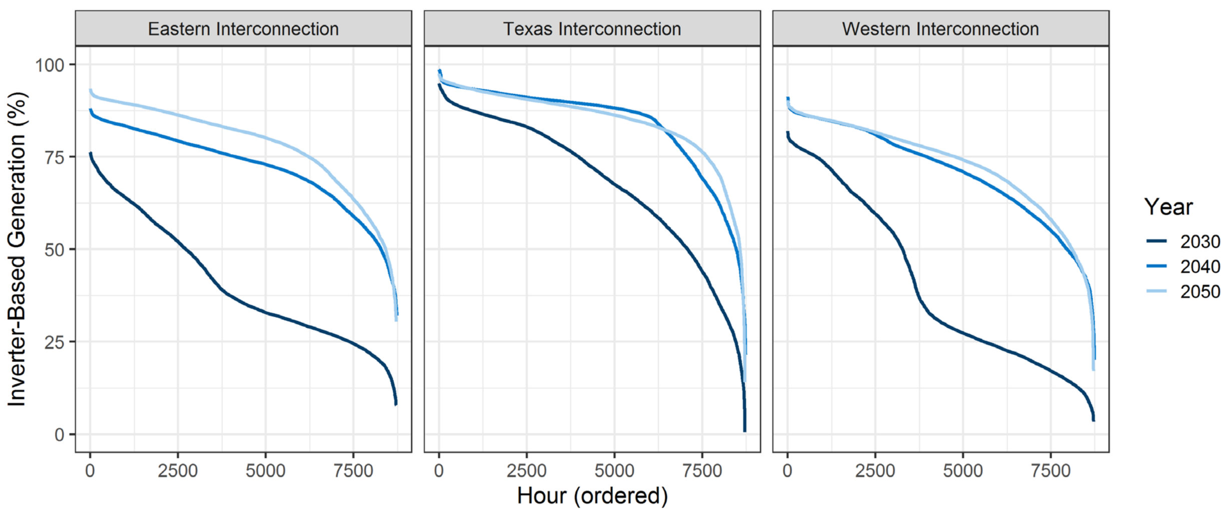
TAP comments during meeting and HECO responses

In general, the probabilistic approach to selecting cases based on the prodsim seems reasonable. However, for the low synchronous generation (SG) case (10th percentile), would it make sense to look at cases with even less SG online since these are the most challenging cases from a stability perspective?

- HECO response: Usually the 10th percentile has the same generators online as the 1st percentile, just dispatched to a different power level, so the impact on stability is about the same.
- TAP response: Makes sense. If there are any cases where that is not the case (i.e. 1st/2nd percentile has different generation online than 10th), we'd suggest also running the case with the lower amount of SG capacity as this may be a worst case stability case. (1/2022 update: We can consider this item complete based on information presented in the Jan 21 meeting.) For future studies, also consider whether reactive power dispatch changes significantly between the 1st percentile and the 10th in a way that could impact stability, for example due to SGs operating underexcited.

How do the dispatches studied relate to the prodsim, in cases where they are not directly taken from the prodsim? Can you share more detail, for example on how the IPP BESS headroom is adjusted to create low headroom sensitivities? How much do the sensitivity cases differ from the prodsim cases?

- HECO response: For example, we run cases where the DER output is very low due to weather, and where the BESS have reduced headroom (especially power headroom).
- TAP response: We recommend making clear how the studied cases relate to/differ from the prodsim dispatch (i.e. what hour), what changes were made to obtain the new cases, and why. We agree that it makes sense to look at low IPP BESS headroom cases; this aligns with past TAP recommendations.



All scenarios are variations on peak load. Could you miss a very low SG scenario by not running minimum load scenarios?

- HECO response: Maui is at 2% SG in several studied cases. On Oahu, IPP headroom is lowest in peak load scenarios.

When converting time-series dispatches into security study scenarios, it may be reasonable to use the 90th and 10th percentiles rather than the absolute maximum and minimum dispatches. Also see several recommendations further below.

Are there any must-run requirements for generation in the production cost simulations that serve as a basis for selecting scenarios? If so, what are they and why are they assumed to be in place?

- HECO response: There is no must-run rule, but there is a minimum inertia rule. We are removing the minimum inertia rule going forward and will loop back with transmission planning. BESS can provide FFR.
- TAP Feedback: When is the minimum inertia rule being removed? (This study, or future studies?)

Violation Tables: HECO shared tables with counts of violations for each island – in several scenarios the number of violations was more than the number of non-violations. It was described verbally that the majority of violations are considered violations because at least one block of UFLS was triggered, and that any UFLS is considered a violation (on Oahu). An open TAP question is what would these violation tables look like today? With this context, the TAP could better ascertain if the system is getting more stable or less stable and for which events. Therefore, the TAP requests for the January meeting that HECO share similar tables of violations for today's system (or a similar proxy – prior to Stage 2 projects) to be shown side-by-side with the violation tables for the future system so that it is clearer how the system is evolving. (1/2022 update: This item remains open.)

It is reasonable to assume little to no impact of DER volt-var or volt-watt control on the timeframes and events studied here (and it would be very difficult to model those functions accurately in PSCAD anyway). However, frequency-watt for underfrequency will be enabled for new DERs installed between now and 2028, and most of those DER systems will have batteries given current trends and tariffs, so they will usually have headroom for underfrequency response. Therefore we recommend modeling new DERs with frequency-watt droop response in future studies. Rough estimates could be used to estimate DER power headroom based on time of day.

- HECO response: We think modeling DER frequency-watt should be possible. Do you trust the DERs to provide this?
- TAP response: New DERs will be certified to provide frequency-watt response in both directions. There could be some failure to perform in the field for various reasons, but most should perform.
- 1/2022 update: When reporting the study, please be clear about how DERs are modeled, including that reactive control is not modeled (which we agree is reasonable for transmission stability study since DER reactive control (volt-var) is slow compared to the simulated events).

We suggest a sensitivity case involving DERs with dynamic voltage support. While this functionality is not required or defined in 1547-2018, it is allowed and may have significant benefit. If this study were to show a benefit, that could be valuable for a future request to enable dynamic voltage support. (The TAP recognizes there would be significant difficulties in deploying dynamic voltage support at the DER level given a lack of standardization or certification in the U.S.)

We understand that this study started before new information on DER momentary cessation (MC) thresholds became available. Now that more information (albeit incomplete) is available, when can it be incorporated?

- HECO response: A major finding of this and past studies is the importance of DER MC. We plan to run a sensitivity on MC thresholds later in this study, including looking at various approaches to improve MC response. (1/2022 update: HECO and NREL shared additional information on DER modeling that the TAP found reasonable. This item remains open pending results of MC sensitivity study.)
- 1/2022 update: The TAP suggests DFRs be installed at some distribution substations to help validate DER models since this is so crucial to system stability and so difficult to capture in models. TAP members have found DFR waveform-level data extremely valuable in high DER/IBR systems. If similar data can be obtained from substation relays rather than DFRs, that is also sufficient. This validation will have to be done carefully as substation level waveform data will have the combined impact of both load and DER. For example, an increase in power injection could be either due to BESS providing frequency response or load tripping.
- 1/2022 Update: "Type 4" DERs (i.e. new 1547-2018-compliant ones) will be capable of bi-directional frequency droop response and will typically (but perhaps not always) have headroom for up regulation since most are now being installed with batteries. This will be difficult to model exactly but should be captured in an approximate way in future studies.

We support the use of a real OEM model for grid-forming IBRs. The Tesla model you are using has a specific flavor of GFM (virtual synchronous machine) that is not representative of many other GFM IBRs in terms of dynamic response.

- HECO response: We also have SMA's permission to use their GFM model. We plan to try a sensitivity on that.
- TAP response: Great. Perhaps you can also try a combination of SMA and Tesla, unless previous work has already shown that the two don't show major adverse interactions.
- 1/2022 update: Hawaii Island has some Type 2 Wind (i.e. not inverter-based). It is modeled in the PSCAD simulations.

What type of load models are used in PSCAD? Would it make sense to include a sensitivity on load model?

- HECO response: We use a ZIP load with no motors. Reactive load is constant impedance, and active load is constant power. Motor loads make PSCAD even slower.
- TAP response: Understood. Perhaps consider a more detailed load model in future work. For example, once GFM inverters models in PSSE are available from OEMs. It is expected that many of the islands have a significant amount of motor load (air conditioners, fans, pumps) – which can play a significant role in recovery dynamics, particularly as the grid becomes more inverter-based. What is HECO's estimate of its motor loads, particularly induction motor load? This estimate can drive the priority of improving load models. This study should be possible to carry out using prototype GFM models are now available in PSS/E from EPRI; preliminary comparisons have been made with OEM PSCAD black box models. If needed, TAP members can support such a study.

With the new single-phase DER models, do you see significant voltage imbalance when the DER on one phase trip?

- HECO response: Yes, but it tends to be localized. The negative sequence voltage may exceed 2% even at the utility-scale generation. It is conceivable synchronous machines could trip on this unbalance; negative sequence protection is not modeled. Also, we wonder if DER will trip on imbalance.
- TAP response: DERs are not expected to widely trip on 2% negative sequence voltage (and 1547-2018 DERs are not permitted to), but we don't have good data on older ones. The risk of DER and machine tripping due to imbalance could be worth looking into in the future.
  It is understood that GFM IBR and synchronous machines (SMs) end up doing most of the heavy lifting in terms of negative sequence current injection; and it's not clear how long these devices will sustain the higher currents and higher rotor heating before protection may act. It is important to understand the negative sequence capability of SMs and GFM IBRs more carefully so that a SLG fault doesn't end up taking out a significant portion of the utility-scale resources a couple of minutes later. Transmission-connected IBRs (both GFM and GFL) will be required to ride through specific durations and magnitudes of negative sequence voltages per IEEE P2800 clause 7.2.2.2.
- TAP response: In the near-term, the following data gathering in this study can help inform the risk to the system from negative sequence voltage resulting from DER tripping on a single phase:
  - What negative sequence voltages appear at the utility-scale generation (machines and IBRs) following SLG faults that trip DER?
  - What are the negative sequence currents from the synchronous machines and utility-scale IBRs following SLG faults that trip DER?
  - What protection elements and settings are in place for the synchronous machines and utility-scale IBRs?
- 1/2022 update: Thank you for sharing the levels of imbalance seen in the PSCAD study. 2% negative sequence voltage is at the threshold that may trigger protection of SGs, Type 3 wind, or substations, which could introduce risk to the system. It will be important to understand how long the imbalance lasts, and how long the protection delays are set for. Protection settings could be inside SGs, not in external relays.
  - HECO response: We don't believe our substations or synchronous machines use negative sequence protection, but will verify.

Do you model transformer saturation?

- HECO response: No. This also makes PSCAD even slower. We don't see much overvoltage, so we are not overly concerned about saturation.
- TAP follow up: If transformers do saturate, for example on voltage recovery following an undervoltage, they would draw more current, which could affect GFM inverter dynamics (i.e. the GFM inverters may hit current limits, so they are no longer grid forming, which can subsequently also impact motor recovery and can cause extended stall.). This may be worth investigating in the future.

Is adaptive UFLS captured in the PSCAD studies?

- HECO response: Yes, PSCAD obtains the UFLS settings from the PSSE model.

The interim results show that reclosing of transmission line protection significantly degrades the frequency response when the fault is not cleared. How prevalent is reclosing of transmission lines?

- HECO response: It is common. Also note that while reclosing into a fault does degrade the frequency profile, we still often fail planning criteria even without reclosing (at least in the PSSE simulations viewed so far).

In response to HECO's request for guidance on how to estimate and mitigate the risk of DER's tripping on ROCOF: Base the analysis of ROCOF on PSCAD, not on PSSE (at least until you have decent GFM models in PSSE, and even then PSCAD should be used to at least spot-check, and modeled device ROCOF responses should ideally be validated against real device behavior). HECO's proposed method of estimating ROCOF appears reasonable (as shown in slide 42). Meta-analysis of past NREL test data shows most legacy DERs are robust up to at least around 2 Hz/s, perhaps higher. IEEE 1547-2018 requires (and verifies through testing) ride-through up to 3 Hz/s. Inverter ROCOF behavior is highly model-specific and can be affected by synchronization method, anti-islanding algorithm, and other control details. Of concern is not just tripping, but also maintenance of synchronization; unsynchronized current injection is a significant risk if widespread. If PSCAD shows ROCOFs beyond 2-3 Hz/s, action may be needed to estimate risk. Such actions could include:

1. Working with DER inverter OEMs to obtain information or models on ROCOF-related behavior and comparing that behavior to ROCOFs seen in PSCAD. The information requested should be quite detailed and include length of ROCOF windows that result in undesired behavior.
2. Asking other utilities (perhaps KIUC?) with high ROCOF concerns whether they have seen evidence of DERs tripping or losing synchronism due to high ROCOF.
3. Lab testing of key inverter models to obtain information on ROCOF responses, and comparison of that information to ROCOFs seen in PSCAD. PHIL testing may also be useful to investigate DER inverter behavior, especially if validated PSCAD models are not available for key inverter models.

The TAP also notes the lack of knowledge of algorithms internal to UFLS relays, and the major risk this poses that simulation results will miss key behavior, possibly leading to an increased risk of unintended behavior in the field with consequences potentially including loss of system stability and blackout. The TAP encourages HECO to pursue details from relay vendors. If vendors are unwilling to provide that information, it would be possible to run PSCAD voltage traces through real UFLS relays to obtain the true relay behavior in a lab. This could be done open-loop, or it could be done using controller hardware-in-the-loop, so that real relays can interact dynamically with a model running in real time to see the full two-way interaction between the relays and the system stability.

- 1/2022 update: Behavior of UFLS relays could pose a high risk or no risk at all. It is difficult to know since their internal algorithms and controls are unknown and vendors are not typically willing to share details.

Given that GFM control is proving to be critical to system stability, have you considered attempting to modify some or all the Phase 1 IPPs to enable GFM control? We think most if not all the vendors could be capable of this soon if not already. Hopefully the inverters chosen can enable GFM with just a firmware change as many manufacturers have stated.

- HECO response: Perhaps we can consider conversion of Phase 1 IPPs to GFM in the frequency response sensitivity.
- TAP response: That sounds reasonable.

The proposed sensitivity related to SCs seems reasonable. We agree with the conclusion that synchronous condensers are very helpful for fault current and voltage stability, and are a known, predictable technology that can greatly reduce the risk of integration of very high levels of IBRs. In cases where SCs are expected to be needed, we would advise HECO proceed with the necessary actions to procure or retrofit them as soon as possible given the lead-time needed to obtain approval and install/retrofit a SC. Any SCs procured/converted may benefit from inclusion of a power system stabilizer.

The proposed sensitivity related to reducing the amount of DERs that perform momentary cessation and/or the voltage levels at which they perform MC looks like a good approach to inform future decisions. However, note that it is difficult to capture the true behavior of a diverse fleet of DERs, especially for fast dynamic events such as recovery from voltages near 0.1 p.u. To some extent this uncertainty can be mitigated by obtaining PSCAD models of DER inverters or through lab testing, if such an effort is deemed worthwhile. It may also be reasonable to make conservative assumptions if the operating costs the assumptions impose are not large.

The TAP requests more detail on the segmentation and characterization of the DER fleet. We would like to understand in more detail:

- What characteristics HECO thinks are important to be understood about DER
- How HECO has segmented the DER fleet,
- How HECO has characterized the behavior of each segment,
- How each segment's behavior has been estimated and checked, and
- What approaches HECO thinks are reasonable & manageable for reducing the remaining uncertainty in DER behavior. The answer to this may depend on the results of the MC sensitivity in the current study.

The TAP asks that HECO summarize this in a few slides for the next TAP meeting.

- 1/2022 update: HECO shared responses to the above questions, and the TAP found them reasonable. We recognize that new information on DER dynamic response is slowly emerging and being incorporated in the models.
- 1/2022 update: Given HECO's finding that ROCOF can exceed 3 Hz/s in many cases, DER ROCOF response is another major unknown that may propose no risk or may propose a very large risk to system stability. This is a complex control response that is difficult to capture in a simple PSCAD model, especially given lack of information on DER inverter control details. Lab testing would be one way to determine DER response details.

The TAP notes the questions about steady state power flow but sees this as lower priority than dynamic stability; we have not focused on this for now.

The TAP supports the plan to check in again in January, and looks forward to the full study results around March, recognizing the limit on the number of sensitivities it is possible to run by March.

Topics discussed in the presentation and not commented on here were generally viewed as reasonable by the TAP members. The overall study approach and initial findings appear reasonable.

We note that there are no cases studied with zero synchronous generation on the three large islands. Is there something in the prodsim constraints that keeps the larger islands from going to 0% SG? Would it not be beneficial to study at least one such scenario, to see what the stability looks like? Gaining confidence in the operability of such a scenario may provide greater operational flexibility by potentially allowing you to sometimes run without SGs if needed in the future. We expect that with SCs and GFM IBRs, a 0% SG scenario is likely be stable, and the SCs can provide fault current to operate protection devices.

- 1/2022 HECO response: We agree a 0% SG scenario makes sense to simulate for Maui. For Hawaii, this could occur in an N-1-1 scenario, so is worth trying.
- TAP feedback: Agreed. This item remains open pending simulation results of 0% SG scenarios and explanation of why no such scenarios occur for Maui in the ProdSim. Especially for Maui, it is unlikely the extremely small amount of SG remaining in the high IBR cases is contributing much to stability relative to the much larger synchronous condensers and GFM inverters. It will be interesting to learn whether the 0% SG scenario differs significantly from the other very high IBR cases on Maui.

Given the large number of PSSE cases that indicated need for further study in PSCAD and the extremely long simulation time in PSCAD, how did you narrow down the list to study in PSCAD?

- HECO response: We based this on planner's experience and tried to pick cases that were representative of several other cases.
- TAP feedback: That appears reasonable until further experience is gained. We'd suggest focusing on a representative sample of high-IBR cases and cases where the system depends on GFM controls for stability. Aim to get at least a couple of different event types (single-phase faults, three-phase faults, and generation loss) for the highest IBR dispatch cases. In addition, use of improved system strength screening methods can help determine when PSCAD is needed. Further, use of improved dynamic models in PSS/E can obtain more in-depth analysis of system response in PSS/E.

Synchronous condenser study:

The TAP notes the various benefits of synchronous condensers for high-IBR system operations and stability. It is noted that 2 synchronous condenser conversions are already approved for Maui. HECO appears to be raising the question of whether the 2 approved synchronous condensers are sufficient, or if more are needed. The TAP believes that grid-forming inverters that are properly configured in the field can provide system benefits very similar to that of a synchronous condenser, albeit greatly reduced fault current contributions on a nameplate MVA-to- nameplate MVA comparison basis. We believe that SCs can help preserve power system stability while operating with extremely high levels of IBRs. Of the SC benefits proposed by HECO, several can be obtained from GFM IBRs. The following are benefits that SCs provide to a significantly greater degree than GFM IBRs:

1. **Transient voltage support:** Because SCs provide high levels of fault current, SCs tend to boost residual voltage during faults more than IBRs of the same nameplate MVA, and therefore could

help avoid DER trip or momentary cessation voltage thresholds being triggered. The TAP encourages HECO to use the ongoing PSCAD study to quantify this to the extent possible, subject to assumptions on DER behavior.

2. **Fault current for protection operation:** Currently available IBRs (both GFM and GFL) typically do not provide much more than their rated current during faults, so relying solely on IBRs for fault current creates a risk of protection misoperation, especially for overcurrent protection, that is difficult to accurately model in sufficient detail to quantify the risk. Given the time constraints, perhaps the PSCAD study could focus on simulating distribution faults on a few low-SCR substations and compare the fault current to protection engineer estimates of fault current time and magnitude needed to maintain protection functionality.
3. **Mitigate DER model uncertainties:** Model representations of DER behavior during transient events currently contain significant uncertainty, as noted in other portions of this document. While additional DER performance data can reduce this uncertainty in the future, no additional information on DER behavior is available to refine assumptions as of today. Because DERs make up a very large portion of generation in many studied cases, the assumptions on DER behavior – specifically the ability for DERs to ride-through high ROCOFs and fundamental frequency undervoltage that would be expected during faults – can have a large impact on system stability. SCs can help mitigate the high ROCOF and the degree of undervoltage during faults to which DER would be exposed. The ROCOF concern could be quantified in simulation by assuming existing (pre-2023) DERs trip on 2 Hz/s ROCOF and new DERs trip on 3 Hz/s ROCOF (worst-case assumptions based on currently available test data and IEEE Standard 1547-2018). Under this assumption, HECO could simulate contingency events with varying quantities of SCs online and observe the variation in system stability. The averaging window used for ROCOF calculation may also vary between DERs and will strongly affect the behavior, so the ROCOF averaging window used for DER models should be stated. The 100 ms averaging window used in the work presented to the TAP is reasonable for future DERs because it is based in 1547-2018; 100 ms could be reasonable as a rough approximation for existing DERs where standards do not state and averaging window. However, the TAP acknowledges that quantifying the amount of synchronous condenser MVA and installation location(s) of the synchronous condensers is time-consuming and would hinge on the assumptions that -- as of today – would need to be made regarding the performance of existing and new DERs on Maui.