IGP TAP Transmission Subgroup

Interim Feedback on System Stability Study

12/20/2021

This feedback to HECO is based on HECO's slides and presentation on 12/13/2021 related to their in-progress system stability study.

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: 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)

HECO presenters: Li Yu, Ken Arakawa, Brian Lee, Marc Asano, Chris Lau, Leland Cockcroft, Andrew Isaacs (consultant to HECO)

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

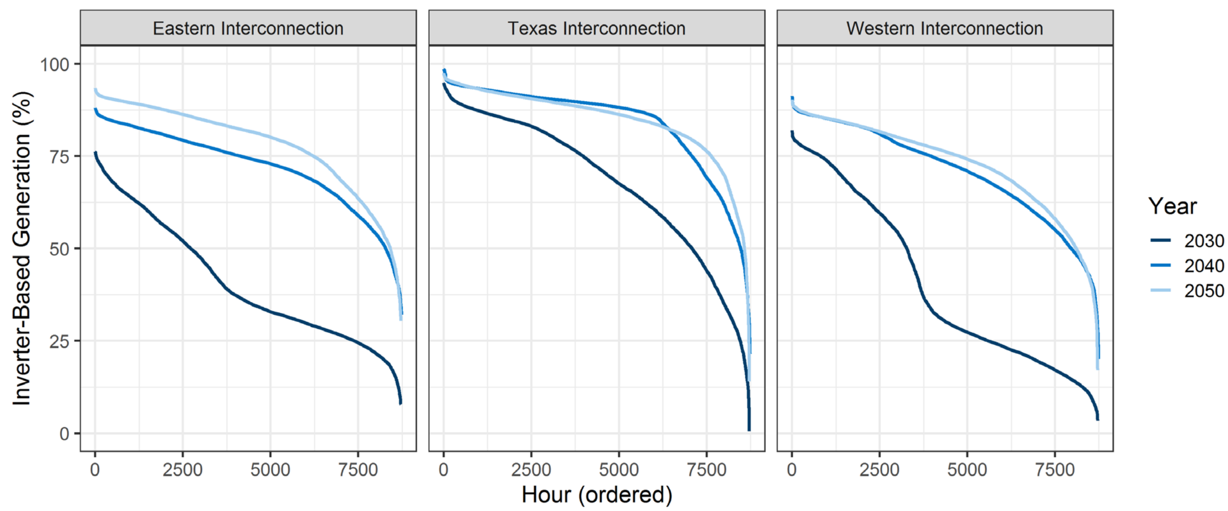
In general, the probabilistic approach to selecting cases based on the prodsim seems reasonable. However, for the low synchronous generation (SG) case (10th percentile), would it make sense to look at cases with even less SG online since these are the most challenging cases from a stability perspective?

- 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. 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?

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.

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.

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.

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 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.

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. 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.

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?

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). 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.

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.

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.

Other TAP comments post-meeting:

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.