IGP TAP Transmission Subgroup

Feedback on Transmission Planning Criteria

10/8/2021

This feedback to HECO is based on HECO's slides and presentation on 10/4/2021 related to their transmission planning criteria.

As with all TAP feedback, please consider these comments as recommendations – the final choices are yours of course. And some of these topics are quite complex, so the few sentences included here just scratch the surface and hopefully point in a direction we think might be helpful.

TAP members attending: Andy Hoke (NREL, Chair), Debbie Lew (ESIG), Matt Richwine (Telos/HNEI), Deepak Ramasubramanian (EPRI). Not able to attend: Dana Cabbell (SCE)

HECO presenters: Ken Arakawa, Li Yu, Addison Li, Marc Asano, Chris Lau, Leland Cockcroft, Lisa Dangelmaier

TAP feedback and comments are divided into three categories:

1. Informational – no action needed.
2. Suggest revising planning criteria before November submission deadline.
3. Consider feedback for future portions of the IGP process (after the Nov deadline).

TAP comments during meeting and HECO responses

The damping ratio criteria and the criteria on control stability can be combined into a single category called "system stability criteria". This can generally include criteria related to stability margins in addition to damping ratio. These criteria will likely need to evolve over time as the industry learns more about operation of high-IBR power systems, and so HECO's planners should retain some flexibility to apply case-by-case judgement and incorporate new learnings.

The 3% damping ratio requirement is borderline low – oscillations with 3% damping can persist for some time. IEEE P2800 requires individual interconnected IBRs to have damping of at least 30%. At the same time, in a very high-IBR system it may be difficult to maintain high levels of damping. Some room for transmission planner judgement will be needed. Damping ratio requirements can be periodically re-evaluated as you learn more.

It is good to quantify damping ratio, as HECO proposes. This can be done not just using small signal models but also using other methods that can more easily be applied during the planning process, including:

- Quantifying the effective damping ratio of simulation or measurement traces (e.g. f, V, P, Q) using techniques such as the matrix pencil, Eigen Realization, or variable projection methods. These methods are mature. NREL and EPRI can provide code/scripts to evaluate these damping ratios.

- Small perturbations can be injected into a black-box IBR model, and the resulting response can be used to generate a Bode plot of the IBR impedance at various frequencies. The same technique can be applied a the IBR POI, and the two Bode plots can be used to estimate the magnitude and damping of any resonances of the IBR-grid system. This method is emerging. NREL can provide scripts/code for it if desired.
- Small signal state space models of the system and its elements can be derived using measurement-based perturbation approaches to complement the Bode plots that are developed. These small signal state space models can be leveraged to identify locations and regions of interest with respect to damping and resonance. This method is also emerging. EPRI can provide scripts/code for this approach, if desired.

What is the threshold for weak grid conditions? (I.e. what is the threshold to require a more detailed study?)

- HECO response: We are considering all buses weak for forward planning purposes.
- TAP follow up: That is reasonable at most buses, though there are likely some exceptions, for example the AES bus. Of course that may change as the system evolves and more buses become "weak". In addition, an IBR at a stronger bus may still have important impacts on grid stability, so it makes sense to treat all large IBRs as needing detailed study, at least until the industry learns more about interconnecting new IBRs in high IBR systems. In addition, the TAP recognizes the current industry consensus that SCR and WSCR metrics cannot fully capture IBR oscillatory dynamics may come into play.

Is there a size limit on IBRs that need detailed study?

- HECO response: Currently all transmission-connected resources require detailed study. Distribution-connected resources follow a different process. Larger ones may require detailed study.
- TAP follow-up: Be careful about making a requirement only on transmission. Developers may try to connect large systems to distribution to avoid detailed study.
- TAP follow-up: Small developers with small projects may push back against requiring PSCAD models. But in the case of Hawaii, it is defensible from a technical perspective, especially considering the future state of the system in a few years.

How can HECO let developers know where substations will be available, especially when interconnecting many projects at one location/REZ?

- HECO response: We will provide developers information on available locations. In the future, with REZ, we will target procurements at REZ zones if selected by the IGP process.

The requirement for inertia and frequency response could be interpreted to exclude fast inverter-based frequency response. The TAP suggests changing "shall carry sufficient inertia and frequency response reserves" to "shall carry sufficient, fast and timely delivered frequency response (including some combination of rotating machine inertia, frequency response reserves, and inverter-based frequency response capabilities)".

The phrase “any aggregate loss of DER” could be misinterpreted to include even unreasonable amounts of lost DER, though we understand that is not the intent. We suggest changing “any aggregate loss of DER” to “expected aggregate loss of DER”.

Incorporate expected aggregate loss of DER into frequency response analysis. (Appears this is already being done.)

Look into potential loss of DER on ROCOF. Look into potential momentary cessation of DERs.

The TAP suggests including fault scenarios in the studied contingencies, not just generation loss. This can be captured by studying “credible contingencies” instead of just “loss of largest generating unit”.

What level of UFLS is acceptable?

- HECO response: Oahu target is no UFLS. Other islands’ target is no more than 1 UFLS block.

Make sure the studied conditions are communicated from Planning to Operations. For example, if the system needs x MW of reserves or if a specific unit needs to have X MW of headroom to mitigate a contingency, operations needs to know about that.

At SCE, the maximum duration for emergency conductor rating use is 4 hours on typical Hawaii transmission voltages. Some other utilities use significantly smaller durations. The duration should be based on physical mechanisms that may lead to conductor failure or other unsafe conditions, as well as on the ratings and parameters of the conductor. We suggest understanding the basis for the duration and selecting a value based on an engineering justification. Operators will need to know what duration was studied.

Do you use any automatic post-contingency actions or remedial action schemes? Some utilities prohibit such actions and others use them a lot.

- HECO response: Not currently, aside from UFLS or UVLS. These are theoretically attractive, but extremely complicated and rely heavily on communications, so we lean towards manual responses.
- TAP follow on: A fast IBR runback scheme may be a feasible automatic action to consider.

HECO asks whether PFR and non-contingency reserves should be set to zero in T-planning studies. TAP Response: A conservative planning process would set PFR and non-contingency reserves to zero unless using probabilistic transmission planning methods. However, this may be overly conservative in some cases, so it would be preferable to examine the impacts of broad assumptions such as this one (i.e. run key cases with and without the assumption) to learn how important they are. Assumptions on reserves may also depend on the purpose of the study. Also see the feedback about making sure the planned level of reserves is communicated to Operations.

- TAP follow on: Are the four planning scenarios enough to inform operations? What about times with storage at high/low SOC, for example? Recent CA shortfalls did not occur at peak load. You can learn which scenarios are important from chronological dispatch.
- HECO response: We do consider scenarios beyond the basic four, including full/empty SOC, units on maintenance, and loss of DER due to weather. We can add language on this. The purpose of the study may also influence which scenarios are studied.

Other TAP comments post-meeting:

As requested, here are some references on probabilistic transmission planning criteria for consideration:

- Jim McCalley of Iowa State University has been working with EPRI and MISO on probabilistic transmission planning. Two presentations are attached.
- Probabilistic Transmission System Planning textbook
- Probabilistic Transmission System Planning article (same author as textbook)
- NERC Probabilistic Analysis Forum. Link contains speaker topics and bios for a past forum. Much of the content appears skewed towards resource adequacy rather than transmission planning, though two speakers from ERCOT and ISO-NE spoke on “probabilistic transmission planning”. Presumably the NERC lead, John Skeath, could provide more information.
- Case Studies on Risk Assessment for Transmission and Other Resource Planning (NARUC Report).