Massachusetts Technical Standards Review Group (MTSRG)
Chair: Babak Enayati, National Grid
Vice-Chair: Michael Conway, Borrego Solar Systems
MTSRG Meeting #4
Date: January 29, 2014
Time: 9AM-2:30PM
Location: DPU Hearing Room A

Attendees

Members:
Babak Enayati, Ngrid
Mike Brigandi - NSTAR
Cynthia Janke, WMECO
John Bonazoli - Unitil
Mike Conway, Borrego Solar (Solar)
Reid Sprite - SourceOne (CHP)
Mike Coddington, NREL (Gov't)
Nancy Stevens, DPU

Bob Andrew - NSTAR
Paul Krell - Unitil
Tim Roughan – Ngrid
Brian Ritzinger , DPU Engineering
Ghebre Daniel – DPU Engineering
Julien Amouyal - SourceOne (CHP)
Gerry Bingham - DOER (Gov't)
Erica McDonnell, IREC (via conf call)
Patrick Retelle, Borrego Solar
Dave Forest - Manager of Interconnection and Study Coordination - NE ISO

Item #1 - 67% vs 100%

Ohio update from IREC (Erica)

- Late 2013 - Ohio adopted intx procedures similar to FERC SGIP
- Supplemental review process, includes 100% min load screening, safety/protection and power quality
- No technical barriers, policy decision for conducting studies under supplemental review
- Expect more states to follow suit
- Basis for 100%? DPU question. Erica: no major technical concerns, emerging best practices were adopted

Utility update (MA)

- Can we address issues using the existing safety, reliability, power quality
- MA utilities **will increase to 100%**, understanding that safety, reliability, and power quality screens can address concerns adequately

- Agrees with Rule21 and SGIP

Comments
- Feeder section vs total feeder? MA recommendation will use feeder section
- Other two screens will remain more subjective to allow utility discretion
- DOER - are other 2 screens going to be more defined? Unitil - we discussed the other screens in creating the tariff, they are intentionally broad to allow utility discretion
- **Future agenda item - each utility's methods for other 2 screens**
- NREL - support utilities discretion, ansi 3.41, ieee519, different standards in MA and in US - but at some point we do need to pin down some specificity. Add context to 2 other screens
- Ieee519, harmonics and THD, doesn't address multiple generators working together, cumulative THD
- PK - standards (ansi and ieee) are used to support application-specific situations from utility to utility based on their system. Interested in hearing concerns on the other two screens from DG - barriers that we experience now in those areas, items to focus on within those two
- Reid - identify means and thresholds per utility, don't have to start at the standard level
- JB - reminder that this outcome came from negotiated outcome. Decided not to clearly define the supplemental screens. Intentional decision
- CJ - new screen went into effect last May, small sample size for supp review so far

- MC, **address as an agenda item, similar to other items**

- Mechanism for issuing recommendation to DPU for 67 v 100? Formal letter, submission from TSRG to DPU
  - DPU approves of this method - the sooner the better because the Tariff is open right now, expedite (10 days?) formal submission can follow
- DF,ISO - ISO supports that process, for requests that fall under FERC jurisdiction. Would like to know how different utilities are applying safety, reliability screens.

Item #2 - ISO concerns – ride-through
- Transmission system stability issues during disturbances. UV ride-through has been particularly problematic. NERC report, distribution voltage falls under 50% within 10 cycles, and we lose all DG. They all reconnect at the same time. So, you lose 20MW of DG, instantaneously, fault is cleared, and 20MW switches back. Has an effect on system stability.
- Increase in UV ride-through duration, ISO request
- How does that align with ride-throguh settings in 1547a?
  - Upon mutual agreement between DG and utility
  - 1547 gives range < 50%, trips off 1sec
  - 50%, 1 sec to 50sec
- DF - 3phase faults are studied in stability model. 3ph fault in central CT or central MA, voltage dips down all the way to the Cape. Losing 25MW is not a huge concern, but NY /New Brunswick has to pick up the load instantaneously (by inertia), 1200MW is a benchmark for what ISO can sustain. May have to limit how the generation can run. 1100 of spinning DG + 300/400 MW of DG would cause a problem.
- DF - Normal 345kV fault, clears in 6 cycles, not usually problematic. Breaker failure can be 15 cycles. 30 cycles for a 115kV fault cleared by zone 2. zone 3 clearing can indicate sequential tripping, can be up to 1sec. So total ride-through could be up to 1sec
- Frequency, NPCC ride thru to 57Hz is acceptable to ISO, no issue.

- BA - stability and dynamics simulations, involve sub-cycle analysis. Inverter ridethru - controls its output to stay synched with system. Ride-through needs to be defined, so if there is a sub-cycle ride-through is disturbed by synchronization
- GB - background from ISO meetings - ISO filed comments for grid mod talking about mitigation capabilities that concern ISO. Retrofitting DG? Could be a concern for DG customers/owners.
- DF - different setting may be needed for rotating DG, but most of the growth is expected to be inverter-based
- Projects that go to ISO review
    - Formal study needed for 5MW and above (i3.9) - reliability committee
    - Aggregate of small generations 1-5MW, needs notification form, not reviewed of studied
    - Short circuit capacity of distribution system, if large DG adds to that, ISO may need to be notified
- PK - oversights in tariff, existing gap in IEEE1547 "and any of its future forms" - as to not force utilities and/or stakeholders to adopt updates to 1547.
- PK - is TSRG tasked with large scale rollouts like ISO ride-through and IEEE updates? BE - believes this is the proper venue for connecting on these topics between the distribution companies
- Mcod - bulk power has true ride-through requirements with penalties. With DG, the goal has been to get offline fast. By default, the machines will stay online as long as parameters allow. 1547a isn't a requirement for ride-through, just allows for it.

- Transmission stability - **add to agenda for future meetings**
- DPU - will ISO manage projects 1-5MW?
    - ISO, DG forecast working group (within ISO) addresses this with a 15yr outlook, considering state policy, etc. Also forecasting future load curve (duck curve) - DF to send link to this group on ISO website.

Break

Item #3 - DG Power factor requirement / Var control

- NSTAR concerns for VAR control and pf requirement at transmission system .95, which means above .95 distribution systems pf
- BE: NSTAR requires unity pf at inverter terminals, not PCC. Voltage issues on system might necessitate STATCOM in parallel with inverter, which changes power factor at PCC - Question, if inverter can accomplish the same result, can NSTAR allow? Inverter manufacturer support claims? Technical explanation
- BA: if one device can do it all, then that may be acceptable. IEEE to date, did not allow that. Test data is needed. A sample size is needed for inverters operating off unity. Disallowing active voltage control prevents hunting (two control systems interacting with each other in a negative way). Load Tap changer at substation, voltage regulators, switched caps, DG on feeder, 2nd DG on feeder, or 3rd.
- BE: technical challenges need to be address in the study. On hunting: voltage regulator timer and VAR control of inverter are different. Inverter reacts within cycles, regulator and LTC has a time delay. That helps solve the issue.
- BA: utilities need to have a plan going forward, and observe the effect in realtime
- BE: 4 inverters on the same circuit, require 3.0MVAr total, but sizes are different, how do you divide that responsibility? Utility EMS system must talk to each inverter

- Nancy: when making the decision to require STATCOM. Is that planning for the future or project specific? BA: project specific
- DF: ISO went through with wind turbines, first used statcoms. Now wind inverters can provide voltage control, and also provide plant management to each inverter
- PK: does the utility have sufficient tools to study the effects of voltage control
- DF: ISO could object to static off-unity power factor - 1.07pu in light load, prefer active voltage control
- BA: wind inverters are using voltage controls for entire facility. At some points (85F degree ambient for example), some of the VAR absorption capabilities may be gone.
- BE: inverters can voltage regulate at night (Q at night). Absorbs active power from utility, and reproduces reactive power
- Mcod: many manufacturers have solved the ambient temperature challenge
- PK: voltage control- inverters can be high speed responsive, can it desensitize islanding detection
- Mcodd: many inverters today have capability to provide var support. Active voltage control is more difficult. Closer to substation, the regulation will have less of an effect due to stiffness. NREL uses layers 1: market level, regulatory, utilities, policy, etc - Layer2: system control layer, how does utility approach it? Layer 3 cyber level, system plant control and communications. All the way down to device level with equipment capabilities.
- MC: DG community still disagrees with full prohibition of off-unity, within reason. All concerns with interfacing with existing equipment, effect during light load, peak load, should be covered during impact study.
- Nancy: resource commitment, which studies does NSTAR sub
- BA: distribution, 50%, transmission is not outsourced

Break for lunch

Item #4 - Tariff language - significant and moderate changes

- Review draft of significant and moderate change, previously reviewed by members
- Mcodd: changes to inverter manufacturer - all inverters that meet UL1741 should behave relatively the same. Is it appropriate to include changing manufacturers under 'significant?'
- "what may have qualified as a moderate change on a project, may be upgraded to a significant change if it has a moderate impact on other applicants"
- Nancy: end result needs to match application. So applications must be updated when changes are made.
- Reid: an updated application is a formal request to make changes to the project
- JB: utilities may need to stop the clock at the point in time that they receive notification that a change will be made. Clock would start again when the updated application is received
- Looking towards timelines and SQM, how long does utility have to determine if it's moderate or significant? Timelines will be on-hold for that duration.
- Nancy: TSRG to submit a recommendation on application change procedure / policy
- PK: we can address the question of making the definitions, but also send a recommendation for policy to go to the DPU
- Significant and moderate changes, considering the effect on other applications, is closely tied to Group Study
- **Babak and Mike to follow up with definitions of Significant, Moderate, and Insignificant**
- **Also, will follow up with a recommendation for Moderate/Significant change procedure**

- Significant: in essence is a new project OR causes moderate change to another application
- Moderate: any change that drives studies to be redone
- Insignificant: a project change with negligible effect