Memorandum

From: Roger Clayton
Re: Notes from FERC DER Technical Conference, April 11 2018

Panel 4 – Collection and availability of data on DER installations

Q1 – Type of information?
Q2 – Current data & sharing?

- APS
  - Each DER site (~80,000) is separately monitored
  - Can have ~50% penetration on a feeder without operating difficulties
  - Depends upon length of feeder & DER location
- NERC
  - Need detailed steady state & stability data for modeling
- PGE
  - Need detailed data for operating distribution system
  - Musk predicts 33% of peak generation to be DER penetration
- PJM
  - DER not participating in wholesale market is not required to be telemetered but can affect BPS
  - Modeling of all is required
- IESO
  - DER visibility required
  - 20% penetration (~4000 MW)
- CAISO
  - 2017 peak load ~50,000 MW with ~7,000 MW PV & ~9,000 MW wind
  - PV expected to grow from ~7,000 MW to 20,000 MW in 2027
  - PV is ~20% of light load presently
  - System operators are presently reactive with "unpredictable load and variable generation"
  - Need DER visibility, command and control specifically switching & ramp rate
- MISO
  - Data sharing between ISO, T & D not presently in place
- EPRI
  - DER must be modeled in aggregate for transmission steady state and dynamic planning studies
  - NERC DER Reliability & Modeling Guidelines are the minimum requirements
  - Netting of DER with load is to be avoided
  - Can start be collecting current DER data by size, location and type for development of aggregate models
  - German experience with 50.2 Hz over-frequency trip settings

- PJM
    - Need for real-time behind the meter data to avoid unforeseen fast load ramp up when sun goes away
- PGE
    - Have noted unusual voltage fluctuations due to PV

Q3 – DER impact on Planning & Operations

- PGE
    - Control over before the meter DER and behind the meter DER is necessary for ramping
- APS
    - 8 MW-Hr battery deferred transmission CAPEX
    - Need to include DER in planning/operating scenarios (max/min DER)
- CAISO
    - Must have frequency, voltage & ramping control
- PJM
    - Data, data, data
- EPRI
    - DER has potential benefit to BPS
    - IEEE 1547 was published last week
    - Smart DER attributes (IEEE standards & NERC guidelines)
        - Autonomous
        - Communication capability (3 protocols)
        - Send/receive command/control

Q4 – DER Long-term projections

- PGE
    - AMR meters at customer level gives basic planning data
    - How to incent customers?
    - Need real-time data for reliable operations
- PJM
    - Scant data availability
    - Presently voluntary data collection
    - Behind meter DER baked into load forecast
    - Reactive operating regimen
    - Need better data projection
- MISO
    - Voluntary DER data not sufficient
    - Policy drivers informs future predictions
- APS
    - Trans planning 10 year process vs distribution planning 5 year process
    - Critical to know DER to inform trans planning
- NERC
    - DER penetration 26 GW-Hrs vs US 170 GW-hr? by 2025? Big.
- IESO
    - DER uncertainty re planning (PV & EV)

- EPRI
    - Need to know status quo to inform future predictions
    - Forecasts bottom up from status quo & top down from policy goals
    - Germany 10 year transmission planning process is open
    - Quasi real-time power flow simulations based on real-time data to develop "heat-maps" to alert operators

Q7 – DER aggregator data

- CAISO
    - Time scale of data communications (seconds not minutes)
- PJM
    - Aggregation is required for ISO operations and markets
- IESO
    - Communication is important from DER to local DSO to ISO

Panel 5 – Incorporating DERs in Modeling, Planning & Operations Studies

Q1 – Best practices, T&D interaction modeling
Q2 – Current DER modeling
Q3 – More detailed DER modeling

- CAISO
    - 10 year DER predictions 7,000 MW (2017) – 30,000 MW (2027) with 50,000 MW peak load (2017)
    - 50% DER behind the meter
    - Aggregated negative load behind the meter DER
    - Generator at BPS node for before the meter DER
- ComEd
    - DER modeled as negative load presently
    - No model of T&D interaction
    - IEEE project on smart inverter connected DER
- NERC
    - NERC DER Reliability & Modeling Guidelines are published
    - Individual & aggregation models are available (based upon what data?)
    - Steady state vs transient models
- Argonne Natl lab
    - Individual modeling of T&D DER is not feasible and co-simulation T&D studies are underway
    - Therefore, must aggregate by type (dispatchable & non-dispatchable), interconnection standards (IEEE 1547 vs CAISO 21?), technology
    - T&D interaction
        - Combined MATLAB simulation
        - Individual T&D coupled simulations
        - Aggregation model
- American Services (MISO)
    - Data requirements in real-time for operations vs future for planning
- Case Western
    - Data requirements function of modeling software used
    - No dynamic models are available for individual or aggregate DER
    - Utilities must verify manufacturers models
    - D is three-phase unbalanced system, T is positive sequence balanced system. Tough to integrate.
- CAISO
    - Composite load model now includes DER PV_A model
        - Inverter modeling (frequency & voltage regulation model et al – see NERC DER Modeling Guideline)
        - Etc
- Duke
    - Aggregated PV modeled as BPS node generator
    - Policy initiative to locate DER at best location

- EPRI
    - Transmission planning dynamic studies models
        - Before the meter DER models available and accurate
        - Behind the meter retail DER requires aggregate model like the CAISO PV_A model. Need more experience
    - Software packages (PSLF, PSS/E, ?)
        - Utility models presently exist to model before the meter DER
        - PV_A model is now available in software packages
        - Must add aggregated D feeders in steady state simulation to allow dynamic simulation to use PV_A models etc.
        - Need better modeling data to utilize these models

Q4 – Contingency Studies & DER

- CAISO
    - Aggregated DER currently not included as a N-! contingency
    - Sensitivity analysis of change of magnitude of DER examined
    - Could be tripping of DER on frequency & voltage perturbations in dynamic simulations
- DUKE
    - Aggregated DER currently not included as a N-! contingency
    - Sensitivity analysis of change of magnitude of DER examined
- NERC
    - Consequential DER tripping must be simulated
- American Services
    - Sensitivity studies only
- ComEd
    - Need to simulate under frequency DER tripping
- EPRI
    - Planning models must evolve based upon IEEE 1547 performance standards selected by states (RTO/ISOs?)
    - Operational models should analyze loss of aggregate DER depending upon DER penetration
    - Need validated DER data
        - Standardization & certification may be required

Q5 – Balancing requirements & DER

- CAISO
    - LSE DER survey & load forecasts used to develop 5 minute maximum ramp rate
- Duke
    - Historical DER data & load forecast to develop reserve & ramping requirements
    - Use CTs for ramping historically but looking at incorporating DER
    - Economic dispatch model down to 200 KW is being developed
- Case Western
    - Problem is using DER resources for system wide ancillary service
- American Services
    - Lack of knowledge of impact of command to aggregator system wide

Panel 6 – Coordination of DER Aggregations Participating in RTO/ISO Markets

Q1 – Distribution Utility (DSO) control over DER wholesale RTO/ISO participation

- PGE
  - DSOs have a responsibility for safety & reliability and should have control over DER operations
  - I/C ~4,000 roof-top solar per month
  - DSO DER studies are complicated by their ability to reconfigure feeders
- East Kentucky Power Coop
  - Distribution feeders are not homogenous & DER can cause reliability problems
  - DSOs need definition of settlement process with aggregator
- PJM
  - DER can connect via:
    - Normal interconnection process
    - Demand response
  - 100 kW threshold to participate in wholesale market and aggregators can make that happen
  - DSOs are involved in the normal I/C & DR process
  - Coordination is clearly needed
- SunRun
  - DSOs should only be able to intervene if there is safety or reliability issue
  - Possible conflict of interest with DSOs who are in the DER business
  - What about the role of aggregators?
  - Should recognize benefits of DER (generation, load modifier, ancillary service)
  - DER aggregators and individual have lots of data to share with DSOs and RTO/ISOs
  - Market solutions should be allowed to define solutions
- EEI
  - How does DER affect reliability, safety & operations for the DSO
  - Need for visibility of all DER & aggregator attributes
  - Someone (DSO?) needs to have responsibility for distribution reliability & safety
- Advanced Energy Economy (DER industry group)
  - RTO receiving aggregator DER data should be provided back to DSO
  - Coordination should be included in IC agreement
- Pacific NW Natl Lab (Jeff Taft)
  - Coordination between RTO/ISO and DSOs should be based upon functional roles & needs
  - DSO DER studies are complicated by their ability to reconfigure feeders
- Missouri PSC
  - DSO and regulator should ensure safety & reliability.
  - DSO should have sign-off authority

Q2 – Need for coordination between aggregators, DSO, TO & RTO/ISO

- PGE
  - Three parties: RTO/ISO; TO; DSO
  - Visibility, communication coordination needed
- Missouri PSC
  - One size does not fit all
- EEI
  - DSO, TO, RTO/ISO & aggregator coordination absolutely necessary
- Sunrun
  - Open data access is desirable between all parties
- PJM
  - Presently coordinating via IC studies but should evolve with DER aggregator penetration
- East Kentucky
  - PJM does UC & Dispatch of our generation resources
  - However, that is different from giving PJM functional control of DER on DSO feeders
  - Need for greater data visibility & coordination

Q3 - DER aggregation in RTO/ISO markets (not addressed)

Q4 – Best approach to DER aggregator retail regulatory authority

- Missouri PSC
  - State needs to be the regulator
- PJM
  - Coordination through the EDCs

Q5 – Grid architecture re DER aggregation

- Pacific NW Natl Lab
  - Meta-structure of coordination framework covers all parties
  - RTO/ISO, TO & DSO coordination not necessary pre-DER
  - Various theoretical coordination frameworks available based on roles & responsibilities of all parties (form follows function)
  - Central vs de-central communication frameworks & everything in between
  - Current electric system is a three-tier model with two boundaries
  - Coordination framework depends upon roles and responsibilities of players which will define relationships & communications
  - May alter role of DSOs to DER/Load entities
- FERC Commissioner Chaterjee
  - Should architecture be defined by FERC
- East Kentucky
  - Need clearly defined settlement process

Panel 7 – Ongoing Operational Coordination

Q1 – Real-time data acquisition & communication technologies

- EPRI
  - TO & DSO SCADA/RTU systems are presently available
  - GMI is also available
  - Distributed Energy Resource M? (DERM) platform to translate various communication protocols
- Open Access Tech
  - SCADA telemetry is old may not be effective for real-time DER command and control
  - New technologies are fast, secure and cost effective re traditional methods
- Kristov (ex-CAISO)
  - Electric services covering DER/load aggregation are going to be behind the meter services
- Miscrosoft
  - Digitization & scalability are new requirements at DSO level enabling DER utilization
  - MS can help with cloud computing etc.
- Open Access Tech
  - Application of new technologies is going to be required with increasing DER penetration
- ConEd & Joint Utilities
  - Visibility & communication from DER aggregators are not presently available & are required

Q2 – What processes do DSO, TO, RTO/ISO & aggregators need for coordination

- ConEd & Joint Utilities
  - Presently using phone & email & needs new real time systems
  - NY is developing pilot programs to explore needs
- Kristov
  - No data available to aggregators on feeder performance
  - DSOs need to decide on their future business model which will inform processes
- SCE
  - Business rules question
  - Can't define coordination processes without defining operating framework (boundary conditions, market rules, system architecture)
  - Federal & State jurisdictional overlap
  - Distribution & Transmission are attaining parity in terms of importance in operating the power system based on DER penetration

Q3 – Minimum set of RTO/ISO protocols, standards & market rules

- Kristov
  - DER outage and derates responsibility of aggregator need to be automated
  - DSOs are going to have new functional responsibilities

- Open Access Tech
  - We should look at lessons learned from OASIS e.g. electronic tagging
- PJM
  - Jurisdiction for DER wheeling
- EPRI
  - Should not be prescriptive regarding protocols like communication standards

Q4 – Should DSOs be able to override RTO/ISO decisions

- ConEd
  - Yes, in emergencies, coordination needed
- EPRI
  - Yes, for safety & reliability
  - Closest controller has precedence
- Open Access Tech
  - Yes but must have formal rules for curtailment
- Kristov
  - Yes but need transparency & rules
- SCE
  - Yes
  - Function of IC scope of study process, technology application (modernization of grid) & explosion of number of elements (scale)
  - May need to change reliability standards to accommodate DER
- PJM
  - Yes, must be fair & equitable
  - Need market rules to cover emergencies

Q5 – Can DER or aggregated DER improve DSO operations and reliability

- SCE
  - Yes, depending upon DER objective
- Microsoft
  - DSO support with on-site resources at data center
- Kristov
  - Multi-use applications are possible
  - Off-setting DSO asset reinforcement

Q8 – Integration of DER aggregation into EMS & DMS

- Open Access Tech
  - Integrate DER EMS into existing EMS
  - Topology plus DSO data will be required to model real time power flows/voltages
- Microsoft
  - Integrating learning processes into EMS
  - Market signal is important
- ConEd
  - Large expenditure in EMS/DMS is required
  - Must ensure value added to facilitate development