NextGrid: Utility of the Future Study

Working Group 1: New Technology Deployment and Gird Integration

Meeting No. 6

February 13, 2018

Meeting Summary

[Note: descriptions of presentations and discussion are condensed summaries and paraphrases]

Working Group Leader: Dr. Mohammad Shahidehpour, *Director, Robert W. Galvin Center for Electricity Innovation, Illinois Institute of Technology*

Topic: Technology Integration in the Grid

a. Distribution system functions in an environment of increasing DER
b. Grid design changes and process required for new technology integration

Agenda Item I: Opening and Introductions

Agenda Item II, Presentation by Dr. Ralph Masiello, (*Industry Expert, Quanta Technology)*

Planning and Operations implications of Distribution System Functions with proliferation of DERs

- Compare distribution system operations today with what they would look like with many DERs and some form of market for distributed resources – DSO, Utility, aggregators to ISO.
- Today, one of the big activities of utility and their operations is outage response. Find the fault, work on the issue, restore service.
    - This will change to where islands form that are self-forming and contain their own generation. If a community microgrid, then utility operations is involved in maintaining load balance.
- There are concepts where microgrids configure themselves dynamically – depending on what is going on – what generation load looks like, where outages are, etc. Utilities manage.
    - Must be woven with scheduled work and restoration
- Today, the primary concern in system monitoring is looking at weak circuits at peak and on peak days. In some cases, shift load to adjacent feeder or shed load. But larger activity in a control room is monitoring for safety – utilizing SCADS and SCADA
- In the future, it will be more than just peak times. System operators will have to be monitoring DERs, dispatch them, monitoring for field safety.
    - This has already shown itself to be issue – too many backup generators are installed near property installed by property owner. Down circuit could be energized by backup

generation. Already shown itself back east. Tree crews are now hung up – have to wait on utility engineer to physically verify that down line is safe before they can work on the trees.

- System monitoring and interaction with field operations becomes more involved
- DER dispatch- Bulk power operation system
- What goes on with bulk power at ISO or utility dispatch now has to come to the distribution side. This means the utility has to forecast the load and DER production. This is something beyond utility operations today.
- Load forecasting and planning- Looking forward, next year, and years ahead, what new load do we know is coming? Look at connection requests. What work is being planned to transfer load to another circuit? What do we anticipate for peak savings?
- Load growth from existing consumption is zero or negative next to EE.
- A big new development is the utility has to forecast DER adoption.
    - For the coming year – connection requests may be sufficient source of info. But beyond the year it is not enough. New state incentives put in, it affects adoption rate, prices change – becomes a more complicated problem than forecasting load growth
- Going forward we could look at electrification. With EV adoption load forecasting is harder.
- Challenges – shift from forecasting peak to now need 87-60 forecast. Condition off-peak is important. Where does data come from? SCADA today, in future it should come from AMI.
- Today, have a manual process of collecting data, getting clean data for DER evaluation, which requires 87-60 analysis, is difficult.
- To forecast the adoption of PV and EV requires a forecasting of customer behavior. This is a new problem for utilities. Collecting customer data and forecasting customer behavior also raises privacy and information security concerns. Then, if you look at past few years, we have seen hotter temps than 15 years ago. A lot of load forecasting of 90-10 process will be a challenge in the future.
- Looking at planning today and tomorrow- new items must be thought about – how to operate the system becomes part of plan now. What will DER dispatch look like and how will it affect the need for new capacity on wires or protection changes?
- DER will affect transfers and become part of load transfer equation. Maybe utility gets involved in DER acquisition if directly connected and acquired under purchase power agreement. Could also see a capacity market. One model – utility determines we could upgrade conductors and spend 700k or we could get 1500 kw of DER and one mode of processing that could be capacity market on distribution feeder. Have to plan for it.
- With technological advances now have – high DER, two-way flows and planners have to become sophisticated about protection. It is technically feasible to set a relay on daily relay through substation auto Scada system, but almost never see that happening because don't want operations touching relays. But with back feed and two-way flows permitting, relay settings must change based on DER. This is a technology issue.
- Around country, utilities do conservation voltage reduction. If you can run distribution system toward lower limit, you reduce kw load of it. Reason is resistive load, will consume less energy if voltage is at 100 percent instead of 105 percent. DERs raise voltage. PV – problem for integration. How will they interact and use smart inverters?
- Technology that can come over horizon, maybe solid-state transformers, but hard to beat cost of distribution system.
- The focus in operations is managing work. Abnormal configurations, doing construction, outage responses. All that including managing DERs.

<u>Agenda Item III: OATI Presentation by Dr. Farrokh Rahimi</u>, (*Senior Vice President, Open Access Technology International)*

DER Operational Impacts

- There are new actors in the distribution system. Active grid edge devices – rooftop solar, microgrids, EVs, etc. have unidirectional to bidirectional implications on the grid. The clear separation of distribution and transmission is becoming fuzzy.
- The issue is to take characteristics and capabilities of distribution edge devices to use them in ways that instead of causing problems for DSO they provide some services that both distribute and build system needs. Utilities know they need grid services called ancillary services – supplemental reserves. Many of these services could come from DERs – ISOs and RTOs have been looking into DR programs. For example, FERC 841 came out in February. FERC 841 instructed to accommodate storage beyond 100kw in their markets to provide all these services. Energy and ancillary services that bulk power needs.
    - Question is, when these DERs provide these services to bulk power system, they will be using the distribution grid. There are implications on the distribution grid. Grid edge devices can be used for aggregated distribution and provide bulk power services. Problem that some of utilities have had is that these devices will be aggregated by aggregators and offered into market, and the utility won't know. The utility won't be informed on what is happening in next hour or tomorrow in their territory. Now, there is a need to provide this information to the utility so they can anticipate what is happening on the system.
- Traditionally, distribution utilities had roles in planning and protection. Now, they find additional roles including forecasting, scheduling, optimizing, and getting involved in settlements for future cases facilitating retail markets. Helping aggregate resources and go into bulk power market, and facilitate the instructions coming from bulk power market to the distribution system.
- In the future, some utilities will have responsibilities to balance the system at lower portions of grid. Bulk power system – ISO-RTO, do not really have visibility to grid edge. When DERs are used to provide regulation or services, may create phase imbalances or other consequences on distribution system. Distribution utility has to take some of balancing responsibility. For example, in Europe – distribution network operators are taking responsibility to help transmission system operator.
- At the retail market level, Distribution utilities as DSO would facilitate bilateral transactions on grid edge actors.
- Whether the DSO is the same as the distribution utility or an independent system operator remains a question.
- There is a possibility for utility to be the DSO and good case for it because they have infrastructure needed to provide necessary services. There should be a clear separation engaged in commercial activity including DER facilitation.
- The distribution system operator and platform providing services will have to provide various functions. Functions include forecasting optimization, facilitating interactions from various stakeholders and customer service. It is a possibility to have separate areas of activity but use the same platform. The Platform disseminates information for DER providers and investors and locational value of devices.
- These functions and services support a need for grid visibility down to the grid edge.

<u>Agenda Item IV, MEEA Presentation by Will Baker</u>, (*Program Director, Midwest Energy Efficiency Alliance)*

What Mechanisms Should be used to get DERs and New Technologies Developed by the Market?

- Technologies rely on end user adoption. At residential, commercial, industrial level, need commitment.
- Utilities are going to need to be as good at forecasting customer behavior as Amazon. Market transformation is one approach to make that easier utilizing specific strategic interventions.
- EE and the way we delivery energy savings is applicable to any new technology in grid space. It is singular equipment being squeezed with technology evolution. Now, more efficient technology is entering market. Baselines are creeping up with federal and state standards and the natural maturing of market. End users are smarter about this and have good marketing techniques.
- Technology development is outpacing ability to judge ratepayer funded utility programs in EE context.
- Transaction costs are increasing. In the same space, as a result of rapid technological change, sensors are becoming cheaper and ubiquitous.
- Market transformation is a possible solution. There are clear benefits – allows for utility, state, and regional coordination. Leverages existing markets to reach economies of scale – happening in specific use cases. Leverages what is already in marketplace. Allows for reduction of per measure transaction cost and administration costs. Allows for long term and sustainable interventions.
- Market Transformation is defined as the use of strategic interventions to speed the adoption of energy efficient technologies, products, or services in a time and place.
- The market transformation process – 1) identify markets for strategic intervention, 2) determine how best you can catalyze that transformation, 3) figure out attribution issues, 4) provide strategic interventions and, 5) monitor progress indicators against initial benchmarks.
- IEEE market transformation illustrates the use of strategic intervention.
- Identifying markets for strategic intervention questions how best to catalyze the transformation? The Midwest and Illinois has been good at educating people by training the supply side and educating the demand side including builders, building engineers, real estate, manufacturers, consumers, any market participant. This makes those who supply EE more likely to provide those goods and services and they are able to do so. Furthermore, by educating the demand side consumers are more likely to want and purchase EE and new technology if they know benefits.
- How do we spur development of new technology products?
- Market transformation is familiar to most. MEEA and PG&E – long term models, benchmarks, project indicators. How do we speed this up?
- NEEP and NEEA –need resource acquisition to resource acquisition and market transformation.
- FEJA allows for 5% of portfolio to be spent on long-term market transformation efforts.
- Market Transformation- What will it take? To use this as a tool to spur new technologies. First, we need to determine what are unique IL barriers to market transformation? In the Midwest? There are natural markets out there, need to identify them and leverage them. Need to deliberately characterize markets, barriers, strategies and expected outcomes. Then conduct market baseline studies, develop performance indicators and determine market effects.
- It is time to try the market transformation approach to pushing out new technologies by thinking of implementation and scaling in meaningful way.

<u>Agenda item V: Panel Discussion:</u>

Q1: Please list or reference some of the most innovative EE technologies that are ripe for deployment that aren't getting attention right now.

Panelists Responses:

- Look at utility R&D departments. There is a Big focus in IL to share what is in the pipeline for utility R&D. At MEEA bringing group together to share pipelines for R&D -- looking at next three pilots. From that, figure out technology we should be focusing on and what is the right approach. Market transformation is second step after figuring out new technology.

Q2: What are some real-life time examples of off peak planning for utilities?

Panelists Response:

- Hawaii is the most famous case in the US. Planners have to look at peak day and off-peak conditions.

Q3: What is your reaction to the argument utilities and regulators are slow moving rather than transformers of the markets?

Panelists Response:

- Utilities and regulators have to get better at market transformation. Will be key to success of the energy industry. There are models in west coast where this has been done. Still room to innovate. Utilities can act more like Google and Amazon. Utilities are best suited to handle things going on with distribution system. Through partnerships, Utilities and regulators working together to act more like unregulated companies like Apple.

Q4: What is it that utilities need to get better at, examples?

Panelist responses:

- Utilities can improve on attribution. Pull funds from different service territory to match size of market and figure out attribution based on logic models instead of tracking the purchase of a specific light build to a specific customer account.
- If you really want to use some of these distributed assets to provide balancing, have to have end design of system. Bulk, transmission and grid edge.
- Learn to listen to bulk power from more than 2 decades ago. Get stakeholders together, bulk power distributors, distribution, tech, and grid operators to work together to come up with rules and protocols.

Q5: should we incentivize market transformation and how in the context of transportation electrification and EVs. How do we support transformation without picking winners and losers?

Panelist responses:

- Market transformation or resource transformation? Markets are an enabler to bring about resource transformation. Coming to incentives. Getting market design right that the people who make investment only see gain they get from investment. But broad stakeholder customer base can gain from other people's investments. If enough put PV on roof, wholesale prices come down. Benefiting -- cheaper energy. How do we in early days redirect some of that diffuse benefit to make it an incentive to accelerate resource adoption? If we get market design right, incentivizes first stage adopters
- Compensating the resources and add it in cost. Main factors. If overcompensate or undercompensate, you are disincentivizing investment in resources.

- What you're describing in the question is an intervention, but not strategic. Need to look at each market, whole supply chain. Maybe you rely on other influencers on demand side. Economically it shouldn't matter. If distorting market as part of it, not being applied correctly. Depends on what market you look at.
- Is the DSO redundant? IL has done good job with restructuring the market with PJM and MISO. Do we really need regulatory intervention on something DSO – is that necessary function going forward?
- Identify some things that DSO needs that they didn't need before. More real-time information -- they have to know what is happening in system. You, as building, may provide valuable services to PJM. Provide regulation, other services, sell energy, buy ancillary to someone else. DSO has to know and be informed in order to operate system in order to accommodate that.
- DSO would be aware if they schedule transaction. They're informed already. They see the schedule a day ahead. If you have aggregators of DER and DR, they are notified through RTOs. Which is independent. DSO may not be, especially one that owns generation.
- In the case where utility wants to both operate and facilitate intermarket – building and selling to one another (microgrids selling to one another) going across system and that is the kind of information I am talking about. Implications of those kind of exchanges on operation of distribution system. If that exists today, deals with some other buyers or sellers, there is mechanism to inform DSO to notify of implications and take actions, then you have it in place.
- Another example is virtual net metering – step towards community microgrid. Can have building ill-suited for PV or DER. Neighbor well-suited. Not only utility and regulatory commission issue. Also, a real estate issues and other. Why couldn't you put 10 mw on big flat building, when 5 is funded by adjacent that cannot have PV.
- We are trying to envision this grid bringing on many more DERs and still currently in a place of policy that looks at specific targets, whether RPS, EE standard, energy storage and other tech. What are the metrics we can use for distribution system that is more much more diverse and facilitates all of this?
- In previous sessions there was talk about value of DERs and locational benefits of DERs and some of functions for distribution system platform. Doing analysis and disseminating information or investment decisions. Invest in rooftop solar, to know where most beneficial. There are some other areas for which we don't have standard metrics – reactive power and voltage support – these are important services for distribution system. At bulk power these are long term contracts, no market for these things and no metrics. For distribution there are missing services that need to be developed and don't have metrics for them. Phase balancing – lots of rooftop in Phase A, EVs in Phase B, and want to solve, can create phase unbalance. What are services that distribute service? Compensate for phase unbalance. Missing metrics and not standardized. Another is metric for resiliency – how do you measure and monetize it?
- DER valuation. Obvious metric is utilization. Electric system becoming increasingly peaky. Ratio of annual energy delivered to peak load gets worse. This is one of drivers for whole discussion to having non-wire alternatives
- metrics will be determined by policy goals – resiliency, clean energy, economics, etc.

- If have a lot of DER, and operating value against market economics, sooner or later, customers have to go on real time pricing. If not, market distortions, opportunities for gaming, subsidies, etc.
- Current policy does not allow using marginal cost to allocate rates. They use average costs. On ComEd's one node system, price is the same wherever you enter the system.
- Not arguing real time is better than average. But if you mix the two, where neither has a tiny share results in distortion. We have lived for decades on average basis. Don't need real time pricing to incent PV. But if we mix two, need to be aware of falls that could wait for us.

Agenda Item V: Format of the Final Report:

- A cost benefit analysis is a good subject for the NextGrid process to look at.
- A cost benefit analysis of all the technologies is out of the scope of WG 1.
- Not all topics identified in the outline have been subject of in depth analysis. T.
- Structure comment- went over a lot of topics – The output from this working group shouldn't be policy implications or approaches. It was great distilling what is coming, potential problems and opportunities. Every meeting we have had has developed core questions. Use the developed core questions to frame what we should talk about next.
- Need report to define and describe various technologies that are available and modernizing the grid.
- Recommend including what people presented in working group meetings.
- Big conclusion is that tech is moving very fast, and evolving fast. Don't know all directions will take. Don't know what all developers are doing. But what we can say is that there are big implications.
- For the outline of the final report working group members should Submit comments on each issue in TOC and represent your viewpoint.

Questions that should be discussed in upcoming working groups

NextGrid Electrification Session Key Question:

1. How do you create a cost-benefit framework that helps you determine the value of avoiding creating new peaks and a massive new infrastructure build on the distribution system?
2. How do you bring the electrification economy to ALL customers? Low-income communities and communities that don't choose car ownership? What models work, and what is unique to Illinois?
3. How do you implement it – through markets, rates, incentives, and programs – to achieve a least-cost and high-benefit future?
4. What are the benefits that can be achieved on electrification beyond the transportation sector?

NextGrid Value of DER Session Key Policy Questions:

1. What technologies do we want to consider?
2. What are the deployment scenarios short- and long-term for them?

3. What information is necessary to assess how technology performs?
4. What information is necessary to facilitate a technology's adoption, and who has that information?
5. How does the technology impact the utility, an individual customer, groups of customers?
6. How are those impacts realized?
7. What do those impacts mean for customers, utilities, and regulators?

<u>Next Grid Advanced Grid Session Key Policy Questions:</u>

1. How do you "get out of the way" of the market for market transformation, while still having new DER as tools for an interactive grid.
2. How does the role of DSO differ from what the RTOs already provide today? What are the new services that will actually be required?
3. How do you address market distortion when you have DER assets getting marginal values while the bulk of customers are using average rates?
4. How to you calculate values of DER to capture the values they bring?
   - Resiliency metrics
   - Measures of "peakiness"/utilization
   - Affordability
   - Environment
   - Economic impact
5. What will it take for some feeders to exceed existing hosting capacity limits without making the last to enter bear the full burden of costs for upgrades? What are alternatives to upgrading the wires and equipment on every feeder and socializing those costs?
6. What is the impact of FERC Order 841 on DSO development? How should Illinois take that into account?