Distributed System Implementation Plans in New York

Summary and Analysis

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Advancing the Clean Energy Future

Background – What are the DSIPs?

On February 26, 2015, the State of New York Public Service Commission ("PSC" or "Commission") outlined a vision for transforming the state's energy grid to a more dynamic and integrated Distributed System Platform ("DSP"). The DSP is a key step towards achieving New York's broader climate and energy goals as outlined by the Reforming Energy Vision ("REV") initiative. The Commission envisions a modernized energy grid that is highly efficient and resilient, produces fewer carbon emissions, and relies increasingly on distributed resources and load management practices. At the core of the Commission's vision for the DSP is greater transparency and visibility for how utilities operate the grid and plan for system needs. The Distributed System Implementation Plans ("DSIPs") fulfill this part of the DSP vision by pulling together and making available electric utilities' plans, processes, and capabilities for implementing REV and fulfilling the DSP.

The DSIPs are a source of public information and will be updated every two years. The intention of the DSIPs is to provide a comprehensive and holistic view of utilities' statuses and their plans to improve their processes and decision-making. The DSIP process does not include the approval of projects, rate design, or cost recovery mechanisms. The Commission has explicitly affirmed that these issues will be dealt with through other rate cases and other REV-related proceedings.

The DSIPs focus on how the utilities will facilitate, integrate, and manage the increasing presence of distributed energy resources ("DER") on the grid. DER include energy efficiency and demand response programs, distributed generation such as solar and wind energy, energy storage, and electric vehicles. The traditional set-up and management of the energy grid is straightforward – electric utilities supply energy to customers through the distribution and transmission system. In the Commission's vision for the DSP, DER will become an increasingly integral part of a modernized, flexible, resilient, low-carbon energy grid. DER represent new, innovative ways of producing and conserving energy and managing energy load.

The following summary and analysis encompasses a review of the DSIP documents submitted by the two largest electric utilities in New York: Con Edison and National Grid. In addition to individual utility DSIP documents, the utilities as a group collaboratively submitted a Supplemental DSIP. Much of the commentary in this review also applies to this Supplemental DSIP document. This summary and analysis will focus on six core areas: forecasting, increasing penetration of DER, planning for non-wires alternatives, plans for advanced metering infrastructure, electric vehicle supply infrastructure ("EVSE"), and DSP investments.[1]

[1] Acadia Center evaluated the DSIPs against the priorities laid out in UtilityVision, a resource outlining specific steps utilities can take to create an energy system that meets our energy needs and supports a fair, healthy economy and environment. UtilityVision, Acadia Center (2015): http://acadiacenter.org/document/utilityvision.

Forecasting – Improving How Utilities Predict System Needs

Utilities use various forecasting models to make informed decisions about investments and projects that will help relieve the future needs of the energy grid. These models make predictions about the energy consumption and demand based on historical data and current trends. DER adoption can have a significant impact on future energy system needs. It will be increasingly important for utilities to be able to adequately forecast DER impacts and adjust the models accordingly as the DSP is more fully realized and the prevalence of DER increase. For example, it has been shown that inclusion of energy efficiency and solar PV in load forecasts reveals that, in many states, electricity consumption is declining or growing much more slowly than previously forecast. Providing this information will help all stakeholders understand how investments in energy efficiency and local energy resources contribute to a more cost-effective grid over time.

The information provided in the DSIPs indicate that the electric utilities are incorporating DER into forecasting and are beginning to improve their methodologies to better incorporate DER impacts. However, the utilities have not provided detailed plans regarding the evolution of their forecasting processes nor have they provided adequate accounting of expected DER-specific impacts on load forecasts as DERs increase.

The Commission asked for a discussion on how different DER are expected to impact load forecasts. The utilities were specifically required to identify the impact of increased DER on forecasting methodology and to describe how they intend to ensure the accuracy of forecasts as DER increase. They were also expected to discuss plans to provide forecasting data across their service territory to outside stakeholders, including plans for providing more granular data than is currently available.

The utilities describe how DER are currently considered and provide descriptions of their methodologies in the DSIPs. They also provide DER-specific forecasting data and outcomes. They also give some descriptions of how they plan to improve their methodologies and how DER are expected to impact load forecasts and forecasting methodologies.

Acadia Center commends the utilities' efforts to include DER in load forecasting and to work to improve their forecasting methodologies. The initial DSIPs present a good start to making these important calculations and methods transparent. However, the DSIPs will be more useful if future iterations provided more granular forecasting data. The current DSIPs do not make it clear when or how this data will be provided. This information is vital for helping DER providers and their planning needs. Future DSIPs should also provide more specific details on plans for evolving forecasting methodology to better incorporate DER impacts. There should be detailed plans in place for how the utilities plan to generate long-term DER forecasts as well as a thorough discussion about the accuracy of DER and load forecasts. Finally, while the utilities are including DER in their load forecasts, the utilities do not expect DER to have a significant impact on load anytime soon, but they make no clear predictions as to when or how soon DER will increase to the point at which they will have a significant impact. The assumptions behind this assertion should be re-examined and re-evaluated as the DSIP process continues.

Increasing Penetration of DER – Plans to Prepare for and Enable DER

The DSP must be able to provide for smooth DER integration as well as actively create an environment that encourages their addition to the grid. Key factors include analysis of hosting capacity (i.e. the ability of different parts of the grid to host DERs without needing significant upgrades) and streamlined distributed generation ("DG") interconnection procedures. Hosting capacity needs to be calculated at the most granular level possible and this information needs to be regularly updated and readily available for DER providers to make informed decisions. Methodologies for calculating hosting capacity need to be uniform across utilities to enhance consistency and reduce confusion across New York. The DG interconnection process should be clear, efficient, and accessible to reduce barriers for generators to connect to the grid.

The DSP vision requires that utilities transition from the role of service provider to the role of market coordinator. The Commission asked the utilities to assess the capability of the distribution system to accommodate and host DERs, including identifying specific high-priority locations. Utilities were asked to provide details about the expected impacts over the next five years for each type of DER and outline approaches to increase the quantity and value of DERs. They were also asked to describe their plans to improve the interconnection process for DGs.

The utilities have described their plans for approaching hosting capacity analysis. They have also provided or have made explicit their intent to provide a hosting capacity map, which will spatially map out hosting capacity and DER potential in the utilities' respective territories. They have also made clear where that information will be available and how often it will be updated. However, initial plans suggest the data will be updated infrequently. Greater emphasis on providing up-to-date information is needed considering the importance of this data for DG developers and other third-party DER providers.

The utilities have provided clear plans for improving DG interconnection by creating and maintaining a user-friendly portal, streamlining the process, and automating certain steps. The utilities provide general descriptions of the expected benefits and challenges of each individual type of DER on the system. However, the DSIPs do not provide any detailed analysis of expected impacts on system operations and load management for each type of DER—or of how these impacts will be handled. This is likely indicative of the current data-gathering capabilities of the utilities with regards to DERs.

The utilities are clearly making some effort to predict and prepare for managing DERs on the system and they have taken steps to make more data and information available. However, it is not apparent that they are prepared to be proactive in encouraging the increase of DERs. There are few descriptions, and no detailed plans, of projects and programs the utilities intend to use to increase the quantity and value of DERs beyond what they are already doing now.

Planning for Non-Wires Alternatives – Reforming How Utilities Address System Needs

Utilities have historically relied on traditional types of transmission and distribution infrastructure projects to meet system needs. Under conventional approaches, if energy demand is expected to increase in a given area, utilities will install larger equipment to handle the increased load. Local DERs that are used to defer or substitute for traditional infrastructure projects are known as non-wires alternatives ("NWAs"). As the energy grid becomes more dynamic and DER levels increase, some traditional projects may be able to be deferred or canceled altogether by NWAs that may be more cost-effective than utility solutions. Rather than continuing to resolve all system needs by using the default traditional solutions, utilities need to prioritize programs and technologies that can avoid or postpone traditional infrastructure upgrades or expansions.

The Commission asked for detailed information regarding the utilities' experience with evaluating and implementing NWA projects. The Commission also asked for descriptions and locations of specific projects that are being considered or could be considered for NWAs. The DSIPs generally provide discussions on the utilities' approaches for addressing system needs and which categories of projects they consider to be suitable and not suitable for NWAs. Generally, the utilities have determined that NWAs are most suitable for projects aimed at relieving load. Additionally, a consistent concern among the utilities is that NWA projects require more lead-time than traditional projects, i.e. NWAs have been deemed unsuitable for more immediate needs.

In their DSIP, Con Edison provides a thorough discussion of the current opportunities for NWAs and describes their main NWA project – the Brooklyn Queens Demand Management ("BQDM") project. In this case, the use of a combination of NWAs and traditional utility solutions is deferring a substation and expansion project that would have been required due to load growth in the Brooklyn and Queens Boroughs. The deferral of traditional investments in this case is resulting in over half a billion dollars in savings. National Grid describes why they have thus far been unable to implement NWA projects and asserts that they have considered and are considering NWAs for a variety of projects.

Con Edison's success in implementing the BQDM project is a great example of how NWAs can be used to address system needs in a cost-effective manner. However, this case should not be understood to support the idea that NWAs are only suitable for load relief projects. Limiting the use of NWAs to load relief problems will miss opportunities to address a wider range of electric distribution system needs. The utilities need to be considering the potential for NWAs more holistically and should continue re-evaluating the suitability of other types of projects. NWAs are likely to be increasingly good solutions to grid problems as data-gathering and other technologies improve and utilities can exert more control and better manage the impact of DERs.

Future DSIPs should provide updated assessments of the types of projects suitable for NWAs. They should also describe how utilities are making efforts to reduce the lead-time required for NWA implementation. The long lead-time the NWA process requires should decrease as the process becomes more standardized and utilities are more familiar with processing and implementing NWA projects.

Advanced Metering Infrastructure – Utilities' Plans to Enhance Information-Gathering

Perhaps the largest obstacle to achieving a dynamic, resilient, DER-integrated energy grid is how little data utilities can gather and share regarding the operation of the grid. Historically, metering systems only needed to fulfill very limited functions, namely, measuring the amount of energy a customer uses within a month. As the grid moves to a networked model, metering and communications technologies will empower consumers to make more informed decisions about energy usage, help policymakers make energy programs more effective, and enable utilities to more accurately (and in real-time) measure energy produced by distributed sources such as solar and wind. Advanced Metering Infrastructure (AMI) will allow utilities to gather more detailed data about energy use by customers. The ability to send and receive more information will enable DERs to have valuable interaction with the grid, and utilities will be better able to predict, control, and optimize the benefits of new technologies.

The Commission required utilities to provide summaries of the utilities' most up-to-date five-year AMI roll-out plans. The utilities both provided the results of their Benefit Cost Analysis for multiple plan options. Both found that full deployment of AMI provides the highest benefit to cost ratio. Con Edison referred to previous filings[2] and

[2] Con Edison filed an AMI proposal on November 16, 2015; the PSC authorized the proposal with contingent requirements on March 17, 2016.

provided very basic descriptions of their plans for full deployment of AMI. National Grid provides a thorough summary in the DSIP and includes their full plan for roll-out in an Appendix.

The full deployment of AMI will greatly increase utilities' data-gathering and load management capabilities with regards to DERs. AMI will improve the accuracy of forecasting, as well as improve management of and understanding of the impacts of increasing DER, and provide many other benefits as well. In the DSIPs, the utilities acknowledge and account for the benefits of AMI and present supportive plans and cost-benefit analyses. Future DSIPs, however, should be consistent in including more details about their plans for deploying AMI rather than referring to other filings. Con Edison, for instance, should at least include their previously approved AMI plan as an appendix to their DSIP. The intention of the DSIPs is to provide a comprehensive source for this information that will be useful for all interested parties. The level of information currently provided is not substantial or complete enough to benefit stakeholders.

Electric Vehicle Infrastructure – Utilities' Plans to Enable EV Development

The State of New York has established clear goals for increasing the number of plug-in electric vehicles ("EVs") on the road. The growing number of EVs will result in greater need for infrastructure, such as charging stations, to support those vehicles. The Commission has established an expectation that the utilities plan for and actively enable the deployment of electric vehicle supply equipment ("EVSE").

The Commission directed the utilities to describe their current and future plans for EVSE deployment, including engagement with consumers and other stakeholders. The Commission specified the expectation that early planning for EVSE should include collaborative initiatives "that can set the stage for accelerated market growth."

In the DSIPs, the utilities have described past, current, and planned EVSE pilot projects. Pilot projects are essential for testing ideas and gathering data before full-scale deployment. For instance, some pilot projects are being used to help utilities gather data on how EVSE is used on a day-to-day basis, which provides insights into the impacts on system load. The DSIPs provide detailed information about these projects but do not provide information about any specific plans for going beyond pilot projects. The Supplemental DSIP produced by the Joint Utilities includes a plan to develop and publish a joint EV Readiness Framework which will assist individual utilities in their efforts to increase EV adoption and support EV markets. This framework is an important step but the utilities have not articulated sufficiently detailed plans for how they intend to engage in the development of the EV market, enable EVSE deployment, or engage with customers.

Distributed System Platform Investment

The traditional energy grid system is structured around one-way power flow from power plants, traveling over transmission and distribution lines, for use in homes and businesses. The REV envisions multi-directional power flows, greater consumer engagement, and third party participation. In the REV, the Commission is directing the utilities to increasingly take on the role of coordinators of the energy market, rather than functioning purely as energy providers and infrastructure developers.

In the DSIPs, the utilities present investment plans to help them transition to their new role. Both utilities present plans to invest in AMI. The utilities also need to invest in systems and technologies that provide information that enables new entrants to participate in a networked and responsive grid. Specifically, utilities should upgrade communications and metering systems, data analytics and data management systems for DERs, and invest in grid operations like voltage control and protective relays. DERs increase system flexibility, but also create more variability in energy use and supply that the utilities will need to handle. These new systems and capabilities will be important for enhancing data-gathering, load management, and integration of DERs, which will in turn increase grid reliability and efficiency. In addition, customer engagement must be improved through understandable billing and secure data exchange platforms.

Conclusion

The DSIP process is critical to implementing REV and achieving New York's climate and energy goals. It is a first step towards a new energy grid and a novel way of planning that future grid. The DSIPs offer a transparent and comprehensive view of how utilities are preparing for and making the way for DER. As DER increases, it will become ever more important to maintain that transparency and ensure that the transition to the DSP is as smooth and efficient as possible.

The utilities will need to continually evolve their forecasting methodologies, particularly for DER. They will also need to plan beyond accommodating DER to the proactive encouragement of DERs on the system. This will include using DER solutions to resolve issues with the grid. NWAs are a unique opportunity to decrease or limit costs for utilities, and thereby consumers. Utilities will need to continually re-assess NWA suitability criteria as technologies, systems, and processes improve for procuring and managing DERs. A major technological step that will aid each of these issues is the deployment of AMI across the entire energy grid. The completion of full AMI deployment will require time and money, but the enhanced data and control capabilities will greatly advance the development of the DSP and will benefit all stakeholders—utilities, customers, and third-parties alike. Utilities also have a crucial role to play in enabling EVSE and the EV market.

As the energy grid evolves and DERs become more prevalent, utilities will increasingly take on the role of coordinators of the energy market, rather than purely being service providers. The DSIPs will facilitate this process by maintaining transparency and providing information so that DER providers and other third-party interests can actively participate in the creation of a modernized, responsive, resilient, low-carbon energy grid. The next iteration of the DSIPs, expected to be filed in June 2018, will provide insight into the progress of this important transition.

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