Beyond Distributed Resource Planning and Grid Modernization

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Executive summary

The energy industry is at the cusp of a paradigm shift in the way it generates, distributes, consumes and stores energy. Significant, multi-faceted changes in energy supply, demand and delivery technology, customer expectations and stakeholder demands are compelling electric utilities to throw out their old business model and develop a profoundly different and expanded grid capability. Changes in planning, infrastructure, and revenue models are imperative to effectively address a range of planning and investment issues emerging from this paradigm shift.

In addition to the historic planning requirements, utilities must now plan for accommodation of rapidly growing quantities of distributed energy resources (DER). DERs typically uncontrolled and intermittent output, from primarily distributed solar photovoltaic (PV) installations, creates a set of new challenges for both the planning and operation of the grid. As the contributions from these intermittent generation sources increase, so does the potential for disruption and instability to the grid and to individual distribution feeders.

With the rapid growth of DER and large scale renewable generation, and the desire by many legislators and commissions to incent their continued growth, the need to effectively integrate distribution and transmission planning with integrated resource planning under a single system framework becomes crucial. Due to the large numbers of distribution feeders and DER sources, incorporating the distribution system is a significant expansion to the scope of the historic integrated resource plans (IRPs) and presents a number of challenges. Additional drivers pushing for improved integration in the planning process include:

- The Clean Power Plan (CPP) and other regulations are pushing out traditional fossil generation and replacing it with greater reliance on renewable generation at the transmission and distribution grid level.
- Renewable generation output does not typically align well with system peak demand, resulting in a need to develop plans that include intra-hour assessments that capture the value of storage and fast-ramping generation sources.
- Utility-scale renewable generation is often at great distances from load centers, making the evaluation of new transmission more important than in the past.
- The advent of distributed energy resources is becoming a significant generation source for the future that is not always under the utility’s control, and carries investment recovery and management issues requiring a deeper level of planning and analysis.

1 DER refers to all types of distributed generation, demand response resources, storage and energy efficiency applications, but at the present time, consists primarily of distributed solar PV.
Traditional IRPs, with their focus on utility scale, fossil and nuclear generation and their interconnections have been the lynchpin of the planning cycle. Despite the “integration” implied in its name, utilities often complete their detailed transmission and distribution plans as largely separate and discrete from each other and the IRP. Now, however, with the business framework rapidly changing, and the use of traditional utility controlled generation decreasing, an integrated and interactive planning process is required. The trend to adding generation sources, and in particular utility-scale renewable generation, remote from load centers, leads to an increased focus on transmission to enable economic alternatives. Moreover, DER provides for additional generation options that (i) are typically not under the utilities’ control, and (ii) may compete with traditional sources of generation. Today’s environment requires a new planning process that integrates and optimizes the entire grid, encompassing a portfolio of options across generation, transmission, distribution and DER.

More detailed data inputs, new analytical methods and new thinking are all needed to address the effective integration of system components into IRPs. This integration can represent a massive scope increase unless organized under a structured process. Scenario-based, deterministic analysis can be used to assess multiple simultaneous planning considerations, with stochastic analysis, or probabilistic analysis, used to refine the assessment of resource and operational requirements under stressed conditions. The stakes are high given the grid operations and societal benefits of applying integrated planning methods effectively and the potential costs of doing it poorly. The investment in such structured, integrated approach is easily justified given the required evolution and refinement of the methods and tools needed to conduct a rigorous and comprehensive utility planning process.

Planning for DER integration – An expanding need
In recent regulatory activity, a few select states have focused on transforming the utility planning process to better align the grid with renewable and other distributed energy resources. Successfully enabling greater DER penetration is just one of the many planning issues utilities are struggling to address, albeit unevenly across the U.S. For most states, DER has not yet grown to levels that impact more than a small fraction of the distribution feeders. As a result, many choose to downplay the industry impact from renewable DER. However, the growth in DER installations continues at impressive rates, with no signs of abating. Figure 1 shows that even with the pending 2016 changes to the Federal Investment Tax Credits, solar is expected to continue its robust growth into the near future.

Cumulative US Solar Additions

Figure 1 – Actual and Forecast/Expected Solar Capacity Additions

A significant transformation of the electric utility business model is virtually assured for the two of our largest states, measured by both population and energy use, (CA and NY) and one of our smallest states (HI). These three states are requiring their investor-owned utilities (IOUs) to take large steps to transform their infrastructure to better enable significant increases in DER. Moreover, they are requiring utilities to support customers and third parties in defining DER sites that are most beneficial or least disruptive to the utility grid. Figure 2 illustrates the wide-spread utility commission and legislative activity in the U.S. focused on rethinking the utility business model and DER integration.

The pressure for increased use of renewable energy continues to be a key driver in the utility transformation initiatives and it is a key element of the CPP. However, the impetus for arguably the most comprehensive initiative, New York’s Reforming the Energy Vision (NY REV), gained momentum, at least in part, to improve the resiliency of the regions electric system after the devastation to the grid and long outages that resulted from Hurricanes Irene in 2011 and Sandy in 2012.

Based on current statistics, New York State has a relatively low solar penetration. However, New York State, through the Department of General Services ("DGS") and New York Public Service Commission ("PSC") are directing the utilities to prepare the grid to enable and incent higher levels of DER. The New York State Energy Research and Development Authority (NYSERDA) has also committed $40 million dollars to subsidize the assessment, engineering and building of community microgrids across the state with a goal of increasing resiliency of the electrical supply to critical community services.3

In California, PG&E’s recent Distribution Resource Plan (DRP), filed on July 1, 2015, analyzed the impact of DER growth for “approximately 500,000 nodes across 102,000 line sections for its 3,000 + distribution feeders.”6 Rather than a few dozen bulk generation plants, PG&E is now analyzing impacts and contributions from 500,000 potential locations for intermittent DER sources. Similar system-wide analysis of the impacts and system needs for DER hosting have been filed by other California investor owned utilities. Massachusetts utilities also filed their system-wide distribution plans on August 19, 2015 in response to the Department of Public Utilities’ Grid Modernization Program requirements. In response to the NY REV requirements, New York utilities must file their Distributed System Implementation Plan (DSIP) by June 30, 2016. Pace Global and PTI expect this commission-driven requirement for expanded integrated distribution planning to rapidly spread to other states. The major uncertainty appears to be how fast this transformation will occur and how quickly it will be adopted in other states.

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3 The data for the map was collected from numerous public websites and data bases.
4 The DSIP filing requirement mentioned earlier is one of the requirements of the NY REV.
5 Siemens is partnered with Booz Allen Hamilton and Power Analytics, Inc. to perform the Phase 1 feasibilities studies on 17 different community microgrids as part of the NYSERDA PRIZE initiative.
While the transformation is in motion, there remains a spirited debate over the benefits and costs of moving the grid to significantly higher DER penetration levels. On one side, advocates of increased DER, and a new utility business model, point to potential environmental benefits and cost savings. Additionally, advocates state that the legacy grid’s inefficiencies, lack of flexibility, and dependence on fossil fuels could be significantly reduced with greater reliance on DER. On the other side of the discussion, industry representatives raise the issues of the significant grid upgrades required to reliably integrate high penetrations of intermittent generation sources and the difficulties of safely and reliability operating an already complex electric system by allowing a larger share of residential and commercial customers to connect their energy sources to the grid.

Regulators and utilities both have valid concerns about the ability of the grid to host large quantities of intermittent renewables. In recent years, Hawai‘i has led the nation with its renewable penetration. However, European countries are well ahead of any state in the U.S. in accommodating large contributions from intermittent renewable energy sources. Figure 3 shows the recent renewable capacity (as a percent of peak load) of eight of the leading states in the U.S. as well as the significantly higher renewable capacity of Denmark and Germany.

The total renewable capacity and the cumulative annual contributions to energy do not begin to tell the full story associated with high levels of renewable penetration. The grid must operate not only under average conditions but also under peak conditions.

Figure 3 – Solar and Wind Capacity, Shown as a Percent of Peak Demand

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7 Based on data from Solar Energy Industries Association, American Wind Energy Association, US Energy Information Administration, The Official Website of Denmark, Platts News: “Analysis: Germany’s Wind, Solar Rise Piles Pressure On Power.” Note Figure 3 shows the installed solar and wind capacity as a percent of peak demand. Peak output from solar and wind rarely coincide with system peak demand.
feeder-level DER generation peak outputs that are over 300% of the feeder peak demands. None of the legacy design and planning for the distribution circuit thermal capacity, protection schemes or distribution substations contemplated these types of system conditions. Even with the strong transmission level grid connections to other utility systems, the German utilities are beginning to see issues at the sub-transmission level voltages that were thought to be limited to distribution feeders or islanded microgrids.9

Figure 4 shows select data for the peak renewable contributions to the coincident system demand. The data for Denmark shows 140%, indicating that the Denmark system was serving 100% of its own demand with renewable sources while exporting an additional 40%, beyond its demand, to neighboring systems.

System-level data is valuable for planning purposes, but system-level data masks the most extreme stress tests to hosting renewable generation on the distribution system. Utility systems in Germany have experienced distribution feeder-level DER generation peak outputs that are over 300% of the feeder peak demands. None of the legacy design and planning for the distribution circuit thermal capacity, protection schemes or distribution substations contemplated these types of system conditions. Even with the strong transmission level grid connections to other utility systems, the German utilities are beginning to see issues at the sub-transmission level voltages that were thought to be limited to distribution feeders or islanded microgrids.9

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9 Germany utilities have found at periods of high renewable generation, when a region is dominated with inverter based generation, sub-transmission level fault currents can be insufficient for existing relays and protections schemes to trigger the needed system protection response to a ground fault. In addition, there is a growing uncertainty on the level of short circuit current available at all voltage levels. With inverter-based generation replacing “traditional” generation, the short circuit levels are decreasing. It is becoming ever more difficult to calculate short circuit currents with the needed accuracy. There is currently insufficient transparency about which types and numbers of inverters are installed in which location – and what short circuit contribution can be expected from each inverter.
Planning for the unknown

Understanding planners’ first axiom – no matter what you predict, the future will be different – utilities need to plan for flexibility, now more than ever. Most commonly, flexibility for utilities has been addressed with scenario planning, i.e., planning around a limited number of materially different, but plausible views of the future, and then selecting the plan that provides the superior performance across scenarios. Utilities must now expand and refine the scope of these rigorous planning techniques to individual distribution feeders. In order to assess impacts to individual feeders and to the system as a whole, utilities must expand the rigor and detail in their system accommodation and planning for the growing sources of DER dispersed across their grids.

Historically, distribution planning was performed substation by substation, and rarely extended to analyze the distribution system as a whole. Most utilities are not yet applying robust hourly, sub-hourly and stochastic or extreme outcome planning and forecasting techniques to distribution planning. Nor are the distribution plans yet facing the internal and external scrutiny characterizing the generation and transmission planning process. However, the standard of integrated and granular analysis across distribution, transmission and generation networks will significantly increase based on emerging regulatory, planning and operational best practice, driven by the need to effectively simulate the growing role of DER in the utility resource mix.

Most of the current and anticipated DER will take the form of solar PV resources. Unfortunately, as illustrated in Figure 5, cloud cover can create a very intermittent and variable output from solar PV.

Figure 5 – Daily Variability of Solar DER

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Figure provided by EPRI in its presentation for a UBS Webcast “Grid Impacts of Distributed Energy Resources” October 23, 2015. The data are shown with the Sandia Laboratories variability index (VI) and clearness index (CI).
Storage additions, expanded distribution automation, and improvements to inverters are effectively managing the intermittency in most instances. Traditional scenario-driven, generation and transmission focused IRPs oversimplify the impact of DER by accounting for it as a net reduction to load only. However, this simplistic approach can work for load forecasts, only if the different scenarios sufficiently address the actual variability of the customer’s load and assured intermittency of the DER.

Solar PV integration studies performed by Siemens PTI have demonstrated that utility power systems must be planned to account for:

1. Peak demand, for which solar generation typically has minimal impact.
2. Peak noon-time output of solar PV can create reverse power flows with intermittent behavior, and
3. Minimum demand conditions which are typically unmodified by solar PV, but can be impacted by wind generation.

In addition to hourly and sub hourly considerations, Figure 6 illustrates that the feeder peak and minimum seasonal demands do not always coincide with the solar PV output. Solar PV adds a new level of complexity for T&D system planning and distribution system capacity assessment.

The variability of a single solar DER installation should have an immaterial impact on its distribution feeder, substation or bulk generators. However, solar output operates in unison across wide areas. With significant solar penetration on a feeder, the feeder can have rapid and profound changes from all its DER outputs. The PV output changes are synchronized to changes in the cloud cover, and in turn create synchronized changes to power flows and voltages, over very compressed time frames. This rapid fluctuation in PV output across a system with high PV penetration creates an expanded set of difficulties at the transmission and bulk generation level. Accommodating this synchronized variation of solar DER output through the entire system requires a flexible and responsive fleet of energy sources (e.g. dispatchable generation, energy storage, demand response) enabled with advanced grid controls and automation. The larger the DER penetration levels, the greater the potential for the impacts throughout the system.

What it all means for planning
For years, electric utilities have conducted IRPs separately from their transmission and distribution planning. IRPs have been the core planning assessment procedure used by utilities to convey their future plans. The IRP defined the generation plan for the future and then the transmission plan and the distribution plan followed.

The options available to the utility are now insufficiently addressed in legacy IRP frameworks. Utilities must include a broader landscape of options and system components to optimize its portfolio. This requires a more integrated planning approach, as illustrated in Figure 7, that encompasses all the elements of the system.

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11 Client data from a study conducted by Siemens Power Technologies International (PTI).
Utilities must consider the impact of increasing levels of DER and the transmission investments needed to bring renewables to load centers as well as intra-hour assessments of the ability of the system to reliably serve load with the growing contribution from intermittent renewables. While this cannot yet be effectively accomplished with a single model, optimum solutions can be developed through iterations between multiple models. The use of multiple models requires iteration of production dispatch models, transmission and distribution grid models with consistent energy, capacity and ancillary services clearing. With consistent input assumptions and simulation model(s) case specifications, a fully integrated and optimal solution can be created and the relative cost-benefit trade-offs among alternative solutions better assessed.

Changes to the industry continue to rapidly evolve with regard to customer expectations, product offerings, service providers, business models, and regulatory expectations.

To be successful in this rapidly transforming environment, utilities must rethink their planning practices. These industry changes require utilities to better assimilate the intelligence, resource choices and behavioral characteristics of the key stakeholders in this new planning paradigm. Ultimately, utilities must improve the internal alignment and integration of their planning activities under a consistent set of planning parameters across generation, transmission and distribution grids.

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