California and New York DER Demonstration Projects

May 2017

Smart. Focused. Done Right.®

scottmadden MANAGEMENT CONSULTANTS

California and New York have approached the question of distributed energy resource (DER) integration differently. The two states have seen very different levels of DER penetration, and their policy goals reflect different objectives. Though both states are using demonstration and pilot projects to test new concepts and models, their differences in current levels of DER penetration and policy goals are reflected in different approaches for demonstrations, as well. These differences are important to note because they will provide important lessons learned about the policy, technical, and business model implications of integrating DERs.

I. INTRODUCTION

Two trends that are reshaping the electric utility industry are the rapid penetration of DERs and the development of technologies that can be used to manage distributed (vs. centrally owned and operated) resources. These trends have prompted regulators to consider pilots both to test technologies and further new planning and analytics methodologies on the distribution system. Two such reform initiatives widely recognized as the leading edge of the DER-integration policy include the Reforming the Energy Vision (REV) proceeding in New York and Distribution Resource Plans (DRP) in California. For more information regarding ScottMadden's assessment of the grid transformation proceedings in California and New York, click here.

In the REV and DRP context, utility research and development activity have evolved from pilot projects to what are being called demonstration projects. The states' approaches to demonstration projects mirror the overall DER policy approaches and penetration levels in each state. In California where DER penetration levels are already high enough to cause operational issues, demonstration projects are more technically focused to assess the grid impacts of DERs and optimize the utility operations and planning. In contrast, in New York where policy calls for an overhaul of the utility business model, the approach to demonstration projects is more wide-ranging and exploratory, and calls for leveraging capital of independent market participants in addition to ratepayer dollars. As such, the demonstration projects in New York typically pair the utilities with third-party participants to take a new entrepreneurial approach to a number of planning and operational functions, whereas the demonstration projects in California require utilities to perform and report on specific DER-integration assessments (like integrated capacity analysis or location-based valuation).

II. CALIFORNIA

There are two primary sources of demonstration projects in California. The first is driven by the California Public Utilities Commission's (CPUC) Public Utilities Code Section 769 (PUC 769) issued in August 14, 2014.[1] The proceeding provided guidance to California's investor-owned electric utilities (IOUs) for developing DRPs to be filed by July 1, 2015, as mandated by Assembly Bill 327 (AB 327). A key element of the DRPs is the five projects that seek to demonstrate how DERs could be integrated into, and even

[1] https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769

replace, traditional power sources on the grid. The intent is for the findings in these projects to inform future grid planning.

The second type of pilot program is the regulatory incentive mechanism pilot (Incentive Pilot) approved in December 2016. The Incentive Pilot would award a 3–4% pre-tax incentive to California utilities for the cost-effective deployment of DERs that defer or displace more traditional distribution capital projects and expenditures. This pilot aims to study how incentives will affect utilities' DER-sourcing behavior. Participating utilities have filed advice letters establishing accounts (IDER Accounts or IDERA) to record and track various costs incurred for the Incentive Pilot associated with deploying DERs that fit the pilot's requirements.[2] [3] [4] This mechanism addresses an issue that is being explored in New York through the development of non-wires alternatives (as part of the Track 1 order).

The following section describes in detail the demonstrations required by the utility DRPs and any results gathered to date. Under the DRPs, California's IOUs were instructed to include the following five types of demonstrations:

1. Dynamic Integrated Capacity Analysis (Demonstration Project A)

This first set of demonstration projects aimed to validate the IOUs' Integrated Capacity Analysis (ICA) tools and methodologies as tools to be applied across the entire distribution system. The demonstrations provided an opportunity to look at ICA from the overall systems perspective, including substation, subtransmission, and transmission limitations. Below is a table summarizing the different Project A demonstrations of the three largest California IOUs—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).[5] [6]

	PG&E	SCE	SDG&E
Objectives	Validate tools and methodologies used to determine the maximum amount of DERs that can be connected without adversely impacting the utility's distribution system functions. More specifically, demonstrate the ICA methodology and consider different scenarios for it. This demonstration is also expected to drive more consistency between utilities, explore multiple calculation techniques, and incorporate other requirements set by CPUC.		
Location	Chico and Chowchilla Distribution Planning Areas	Orange County and Tulare County Distribution Planning Areas	Northeast and Ramona Districts
Timing	Complete as of December 2016		
Results/ Findings	▪ The California IOUs aligned on methodology, producing consistent results for the test circuit ▪ Data sets generated by the hourly ICA were very large. An assessment of IT requirements and what amounts of data are actionable and feasible will be important; computational times for the iterative method used were very long, and as such, a blended approach to iterative and streamlined was deemed more useful ▪ IOUs attempted to use the new power flow software suites to optimize the ICA tools, but results were poor, as the models were not yet production ready. Significant time and effort still need to be put forth to develop these new tools		

[2] Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot, Decision 16-12-036. CPUC. December 15, 2016
[3] Advice 5017-E: Establish the Integrated Distributed Energy Resources Account. Pacific Gas & Electric. February 10, 2017. https://www.pge.com/tariffs/tm2/pdf/ELEC_5017-E.pdf
[4] Advice 3565-E: Establishment of the Integrated Distributed Energy Resources Ratemaking Mechanisms Pursuant to Decision 16-12-036. Southern California Edison. February 24, 2017. https://www.sce.com/NR/sc3/tm2/pdf/3565-E.pdf
[5] PG&E, SCE, and SDG&E Distribution Resource Plans
[6] PG&E, SCE, and SDG&E Demonstration Projects A & B Final Reports

	PG&E	SCE	SDG&E
	▪ SCE and SDG&E developed mapping tools that were published online to illustrate locations with integration capacity for DERs. As of December 2016, PG&E's maps were yet to be published		

2. Optimal Location Benefit Analysis Methodology (Demonstration Project B)

This second set of demonstration projects sought to demonstrate the "ability of DER to achieve net benefits consistent with the Optimal Location Benefit Analysis." The table below summarizes the Project B demonstrations of the three California IOUs.[7] [8]

	PG&E	SCE	SDG&E
Objectives	Demonstrate Commission-approved optimal location benefit analysis (LNBA) methodology for one near-term (0–3 years) and one longer-term (3 years or greater) distribution infrastructure project that can be deferred due to the integration of DERs. The demonstration project will further accomplish several objectives: 1. Identify traditional projects that can be deferred by DERs and show LNBA calculations under two DER-growth scenarios 2. Identify the operating characteristics of a DER project that can defer/eliminate a traditional project 3. Determine length of deferral achieved by DERs 4. Calculate net benefits resulting from installation of the DER project		
Location	Chico and Chowchilla Distribution Planning Areas	Rector System in Tulare County	Northeast planning district, where a variety of distribution projects are planned
Timing	Complete as of December 2016		
Results/ Findings	▪ All three California IOUs collaborated with Energy and Environmental Economics (E3) to develop an Excel tool for estimating location-specific avoided costs of installing DERs. This LNBA tool will need to be improved to support the benefit analysis of deferring a project with multiple locational elements. The LNBA public tool will be useful to DER developers seeking to understand where best to site DER projects ▪ All three California IOUs produced heat maps that identified projects which may be deferred, as calculated by the LNBA tool. PG&E identified 10 potential projects, SCE five, and SDG&E four. The LNBA tool developed collaboratively was used to calculate the transmission and distribution (T&D) deferral value and system-level avoided costs for each project[9] ▪ The impact of the very high DER-growth scenario on distribution projects and their deferral requirements (i.e., magnitude, hours, and in-service date) was not necessarily consistent or intuitive. In some cases, impacts were minimal, in others substantial; while in several cases, the magnitude of load reduction requirement actually increased. These results bear further investigation ▪ Demonstration B showed new planning analyses methods that are expected to progress as more experience is gained. The IOUs expect that portions of the analyses will be incorporated into their annual-planning process and CAISO's transmission-planning process		

The other three sets of demonstration projects are field studies and are still under development.

[7] PG&E, SCE, and SDG&E Distribution Resource Plans
[8] PG&E, SCE, and SDG&E Demonstration Projects A & B Final Reports
[9] Further details for each project, including the length of deferral that may be achieved for each project, can be found in Chapter 5 of each utility's Demonstration Project B Final Reports

3. DER Locational Benefits (Demonstration Project C)[10]

	PG&E	SCE	SDG&E
Objectives	Implement a field demonstration project that can be used to validate the ability of DERs to achieve net benefits for at least three DER-avoided cost categories or services, consistent with the LNBA methodology. Expected outcomes include validation and calibration of the LNBA methodology and recommendations on incorporating DERs into utility planning and operations. This demonstration may include studying, analyzing, and confirming whether DERs can function in an integrated manner to meet future local capacity requirements and energy needs. The project may also provide information on the cost to meet customers' energy needs.		
Location	Central Fresno Distribution Planning Area	Preferred Resources Pilot Area (Irvine substation), a pre-identified area with a transmission constraint that could be resolved through the addition of gas-fired generation, transmission upgrades, or alternatively, the use of DERs.	Circuit 701 connected to Mission substation has a high concentration of rooftop solar and a high number of existing smart inverters (ongoing pilot project).
Timing	Demonstration C projects for all utilities were approved in February 2017, with an expedited commencement of within 30 days after approval. Assuming construction of new DERs is needed, this schedule requires the solicitation process to be complete no later than 10 months from approval of the decision, at which time the utilities will file their contracts for approval. The schedule also requires the utilities to file three progress reports after commencement of data gathering for the projects.[11]		

4. Distribution Operations at High Penetrations of DERs (Demonstration Project D)[12]

	PG&E	SCE	SDG&E
Objectives	Demonstrate a system that can operate multiple DERs (both third-party owned and utility owned) to provide grid benefits and assess how high penetration of DERs will influence distribution planning and investments.		
Location	Gates Distribution Planning Area	IGP project area or Johanna Jr. substation	Valley Center Substation
Timing	Demonstration approved on February 2017	Commence no later than one year after DRP approval. Aspects of this project are already in progress and funded through the existing EPIC program. Within 12 months after DRP approval, SCE will modify any necessary components based upon the Commission's approval. Demonstration was approved on February 2017.	Commence no later than one year after DRP approval and complete within four years. At present, SDG&E's proposed Demonstration Project D is not approved. SDG&E is directed to work with the staff of the Commission's Energy Division to determine if the goals and objectives of Demonstration Project D could be addressed and accomplished through Demonstration Projects C and E.

[10] PG&E, SCE, and SDG&E Distribution Resource Plans
[11] Decision on Track 2 Demonstration Projects, pg. 10
[12] PG&E, SCE, and SDG&E Distribution Resource Plans

5. DER Dispatch to Meet Reliability Needs (Demonstration Project E)[13]

	PG&E	SCE	SDG&E
Objectives	Demonstrate the ability to manage and operate multiple DERs using one or more dedicated control systems within a microgrid system, potentially with both third-party and utility-owned DERs supporting the customer loads. This demonstration may also define operational functionalities necessary to support situational awareness, coordination of DERs, and reliability services to be achieved.		
Location	The Angel Island project presents an alternative to cable replacement and will demonstrate the deployment of on-island DERs to meet reliability needs. It is intended to operate an optimal DER portfolio that will run 24/7 and 365 days to maximize the benefits of the DERs and reduce the dependency on the cable.	North Orange County	Borrego Springs is a distant and isolated load pocket entirely surrounded by a state park. It has a high concentration of solar generation with a potential for reliability enhancements. There is also an opportunity to balance supply and demand to be more self-sufficient.
Timing	Commence no later than one year after DRP approval. Currently, PG&E's proposed Demonstration Project E is not approved. It can file within 45 days of the decision to request approval for a new Demonstration Project E.	Commence no later than one year after DRP approval and complete within three years. Currently, SCE's proposed Demonstration Project E is not approved. It can file within 45 days of the decision to request approval for a new Demonstration Project E.	Commence no later than one year after DRP approval and complete in late 2018. SCE's Demonstration Project E was approved on February 2017, with an expedited commencement of within 30 days after approval.

The first two demonstration projects have provided valuable insight into the analyses necessary to assess the amount of DERs that the existing grid can accommodate and how to site them in the most beneficial locations. These provide important learnings as other states begin to appropriately locate and integrate these resources, particularly as utilities look to use DERs to offset utility capex. The field demonstrations will provide important lessons on DERs' operational characteristics and the steps that must be taken to reliably manage them.

III. NEW YORK

Central to the REV undertaking in New York is the notion that the utilities will act as a Distributed System Platform (DSP), defined as:

> "[A]n intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale and bulk power system."[14]

[13] PG&E, SCE, and SDG&E Distribution Resource Plans
[14] Track 1 Order, pg. 31

This is no small task, and as such, demonstration projects were introduced through the Track 1 Order to encourage utilities to test concepts that would reshape the traditional utility into the DSP. REV demonstration projects must meet the criteria spelled out in Figure 1:

Figure 1 – NY REV Demonstration Project Criteria	
The utilities are to partner with third-party technology providers and propose projects that meet the following eight criteria:	
1. Partnerships with third-party service providers, leveraging third-party capital where possible 2. Problems or questions raised by the utility, with solutions delivered by the marketplace through RFI/RFP solicitation 3. Clear delineation of economic value between the customer, utility, and third-party service provider and a clear delineation of capital expenses between rate-base and competitive markets 4. A competitive market for grid services, with the utility owning DERs only if the market is unwilling to address the need	5. When demonstrations are not competitive, rules to enable a competitive marketplace must be developed. In addition, regulatory proposals to ensure safety, reliability, and consumer protections must be developed 6. Demonstrations should inform pricing and rate design modifications 7. Demonstrations should consider deploying advanced distribution system technologies 8. Utilities should include various residential, commercial, institutional, and industrial customer participants

There are currently 18 active REV demonstration projects across the five IOUs, testing a variety of concepts. With the exception of the Smart Home Rate demonstration projects,[15] each utility has flexibility to design and propose any project as long as it meets the criteria above. Nonetheless, common themes have emerged. Each of the following topics have had multiple proposals:

1. Rate Design (five projects) – Testing various implementations of time-of-use rates (through the Smart Home demonstrations) or price signals and tools for demand reduction during peak hours
2. Customer Engagement Platforms and Marketplaces (four projects) – Testing the concept of the DSP as a platform marketplace where customers can gain better insights to their energy usage and purchase products that promote more efficient usage
3. Energy Storage Business Models (three projects) – Testing various configurations of energy storage and how to monetize the value stack
4. Community Energy Models (three projects) – Testing the concepts of community-based models in various configurations, as a voice of the customer forum, deployment of a microgrid for resiliency, or deployment of solar to offer low- to mid-income customers access to DER benefits
5. Distributed Generation (DG) Interconnection and Hosting Capacity (two projects) – Testing alternative models to facilitate DG interconnection and/or increase the amount of DG that can be hosted on a circuit

There are also two projects that don't fit neatly in one of the categories above—National Grid's Buffalo Niagara Medical Campus DSP Engagement Tool and Con Edison's Building Efficiency Marketplace, which leverages meter data, analytics, and benchmarking to engage commercial customers with energy efficiency and demand response solutions (both are described below).

[15] The Smart Home Rate Demonstration projects were mandated as part of the Order Adopting a Ratemaking and Utility Revenue Model, also known as the "Track 2 Order"

Utilities are still filing demonstration project proposals, and even the first round of proposed projects are just beginning to yield reportable results. As they continue to mature, these demonstration projects will provide the first implementation level results of key elements of REV. Four specific projects to highlight the transformative aspects of REV they are testing include:

- National Grid's Buffalo Niagara Medical Campus DSP Engagement – Testing the communications between a DSP and network-connected DERs on a small scale. Notably, this project is evaluating a financial model for the market participation of DERs based on the Value of DER, using the NYISO Locational Marginal Pricing plus the Value of DER to the distribution system.
- Con Edison's Storage on Demand – Testing the ability of mobile storage units to provide "stacked" value by providing bulk market capacity, frequency regulation, or operating reserves, and addressing local distribution system needs to offset traditional T&D assets as non-wires alternatives. For more information on the value stack of energy storage, click here.
- AVANGRID's Flexible Interconnection Capacity Solution – Testing a new model of interconnecting large-scale controllable DERs, which has implications both for increasing the hosting capacity of the system by enabling the utility to interconnect larger systems than it otherwise would have been able to without the ability to curtail and the Clean Energy Standard by providing a blueprint for interconnecting the large-scale renewable resources needed to achieve New York's clean energy goals.
- AVANGRID's Energy Smart Community – Testing a planning model with greater stakeholder involvement in Ithaca, NY, including the advanced metering and distribution automation infrastructure necessary to more dynamically provide and measure response to time-varying price signals. This project partners AVANGRID with Cornell University, SolarCity/Tesla, BMW North America, and Distributed Sun. AVANGRID's Smart Home Rate project was incorporated into the ongoing design of the Energy Smart Community.

A complete summary of the New York demonstration projects is provided in Appendix A.

IV. ANALYSIS AND CONCLUSIONS

California and New York have been widely hailed as leaders in grid transformation and integration of DERs. The Public Utilities/Service Commissions of both states have recognized the value in testing and deploying solutions at a small scale prior to wide-spread implementation. This is a prudent approach given the complexity of the interwoven proceedings in both states, and it allows the utilities and DER providers the opportunity to more quickly evaluate new studies or business models and adopt or discard these elements accordingly.

The most notable difference between the two approaches to running demonstration projects is the prescribed nature of the California projects versus the open nature of the New York REV projects. This difference is logical, given the more aggressive mandate in New York to establish a transactive energy marketplace and redesign the utility business model. To redesign a business model requires an entrepreneurial approach, which itself requires the flexibility to propose new methods to generate value and mechanisms to share that value equitably among value chain participants. This flexibility is reflected in the open-ended nature of the REV criteria and the greater volume of project submittals. The open and entrepreneurial approach is also evident in the mandate that each demonstration project be undertaken with a third-party partner, rather than being mostly utility led. New York is also focused on how to facilitate greater amounts of DERs.

In contrast, California is working to efficiently and effectively integrate the large amounts of DERs on the system. The DRP demonstration projects, versus the NY REV projects, focus more on technical and operational requirements, mainly related to driving consistency in tools for planning DER incorporation into utility systems, and gaining a better understanding of how to operate systems that integrate DERs, including those owned by third parties. That scope necessitates greater constraints for project proposals in order to have like-to-like comparisons of project results.

Though there are major differences between the two sets of projects, there are also some common elements. The use of DERs to offset traditional capex is an area of focus in both states. Both are also considering advanced distribution technologies, but again, California's approach is more prescriptive as it specifies what these advanced distribution technologies are required to do (e.g., demonstrate the capability of managing and operating multiple DERs).

As other states and regulators consider implementing demonstration projects, they should first assess their current DER penetration levels and the breadth of their grid transformation objectives. States with high DER penetration that are already experiencing operational and planning challenges and wish to streamline DER integration, should consider the demonstrations underway in California. On the other hand, states and regulators wanting to modify the utility business model to include greater third-party market participation may want to consider New York's experience. It's too early to tell which approach will ultimately yield results that move the utilities, their customers, and third-party stakeholders closer to each state's respective goals. Currently, the California projects, given their earlier start and narrower scope, have produced more tangible results than the New York projects, which are largely in the initiation phase. As the results of these demonstrations come in, both states will benefit in applying their lessons in furtherance of greater, reliable integration of DERs. Other states will be wise to consider lessons learned, as they develop both technical standards and business models to accommodate greater amounts of DERs.

ABOUT SCOTTMADDEN'S GRID TRANSFORMATION PRACTICE

For more than 30 years, ScottMadden has helped our clients transform the way they operate, plan, and maintain the grid and interact with their customers. The Grid Transformation practice focuses on helping clients adapt to the myriad changes driven by the increasing penetration of distributed energy resources, such as distributed generation, storage, demand response, and microgrids. We help our clients choose the path that meets their reliability, customer, and regulatory goals, and then we help them implement it.

ABOUT THE AUTHORS

Cristin Lyons (cmlyons@scottmadden.com) is a partner in ScottMadden's Raleigh office and leads the firm's grid transformation practice. Chris Sturgill (chrissturgill@scottmadden.com) is a senior associate in ScottMadden's Raleigh office. Freedom David (freedomdavid@scottmadden.com) is a senior associate in the Atlanta office.