THE 51ST STATE

51st State Perspectives

DISTRIBUTED ENERGY RESOURCES INTEGRATION

POLICY, TECHNICAL, AND REGULATORY PERSPECTIVES FROM NEW YORK AND CALIFORNIA

PREPARED BY

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TABLE OF CONTENTS

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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 SEPA

SEPA facilitates collaboration across the electric power industry to enable the smart deployment and integration of clean energy resources. Our focus centers on solar, storage, demand response, and other enabling technologies.

ACKNOWLEDGEMENTS

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Executive Summary

New York and California are leading the country in their approaches to integrate distributed energy resources (DERs). However, those approaches differ in some important ways including their starting points. In New York, DER penetration has been minimal to date, and the Public Service Commission (PSC) has adopted the view that "if we build it, they will come," creating the infrastructure and incentives to bring DERs to the state. Creating a path to changing the utility business model and "market animation" have featured prominently in the state's Reforming the Energy Vision (REV) proceedings. REV consists of myriad interlocking proceedings that address demonstration projects, large-scale renewables, rate reform, low income issues, planning the grid, and more. These initiatives impact each other, and the incentives, requirements, earnings opportunities, and metrics are linked and overlap.

In California, legislators and regulators have adopted a different approach. Rooftop solar installations have introduced operational and planning challenges for utilities. Utility regulators in California began by focusing on the technical aspects of integrating DERs and are now moving to implement policies that address the alignment of utility incentives. Importantly, California is taking a step-by-step approach through a series of legislative and Commission actions that address discrete issues presented by DERs. This is a slightly more cautious approach that focuses on piloting key changes before finalizing rate reforms or other changes to the business model.

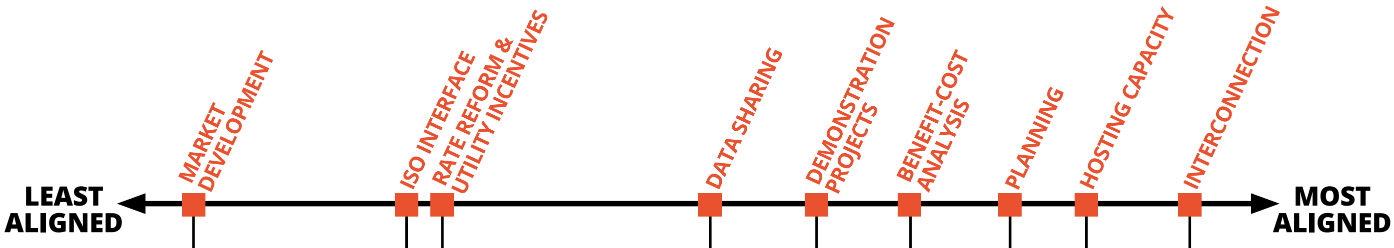
To facilitate DER integration, both states are working to improve the interconnection process and expand hosting capacity analysis. They are considering the impacts of DERs to the distribution planning process and are developing processes that use DERs to offset traditional utility capital expenditures (Capex). Each is developing analyses to compare non-wires alternatives (NWAs) to traditional infrastructure to assess these opportunities. Also, as part of the planning process, they are considering how best to share planning and system data with third parties.

The demonstration projects being developed in New York seek to demonstrate both technical and business model alternatives for DER integration. Whereas, in California, pilots are addressing specific technical questions. Both states are considering how best to reform their rate structures. New York provided guidance through its Track Two order on how to begin the move away from traditional cost of service ratemaking. A separate state proceeding deals with the future of net metering. In California, the Commission is addressing the future of net metering in one proceeding, while piloting alternative incentive approaches for NWAs in a separate initiative.

While New York and California are starting from very different places (regarding market structure and DER penetration), and each has a different end goal for the future of their respective marketplaces, there are common elements between the two states' approaches. Other states will benefit from the New York and California experiences both in areas where they are pursuing very similar tactics and in areas where they diverge. This report will lay out the key similarities and differences between the two states' paths to increase the penetration of DERs, so others may adopt and/or adapt them to facilitate their own market transformations.

The graphic on the next page illustrates areas of alignment and divergence between the two states' approaches.

CALIFORNIA AND NEW YORK DER INTEGRATION: A CONTINUUM OF APPROACHES



MARKET DEVELOPMENT
NY has an explicit goal of "market animation." CA does not.

ISO INTERFACE
NYISO's DER roadmap focuses on integration of dispatchable resources only. CAISO has implemented the aggregation of dispatchable and non-dispatchable DERs.

RATE REFORM & UTILITY INCENTIVES
NY's Track Two is more focused on Earning Adjustment Mechanisms and Platform Service Revenues than residential rate design. CA has initiated an entire proceeding regarding residential rate design.

DATA SHARING
Both states focused on providing customer and system data. CA is ahead in both.

USE OF DEMONSTRATION PROJECTS
Demos in NY test both business model changes and technical integration of DERs; in CA, the focus is on testing out concepts in Distribution Resources Plans (mainly technical integration).

BENEFIT-COST ANALYSIS
NY has adopted the Societal Cost Test; CA is considering the SCT. CA is focusing on valuing benefits with locational granularity. In NY, the focus will first be on analyzing hosting capacity. CA is doing both concurrently.

PLANNING
Comprehensive plans for the integration of DERs, including hosting capacity and identifying beneficial locations for DER deployment. Both looking at DERs to offset utility Capex. DER penetration rates, particularly solar PV, is a notable difference.

HOSTING CAPACITY
Similar efforts to assess hosting capacity and make it available to DER providers.

INTERCONNECTION
Focus on speeding up the process and automating technical screening.

Source: SEPA & ScottMadden, 2016

The 51st State Initiative facilitates a collaborative platform across the power sector to discuss the future of the electric industry. Designed as an alternative to the contentious debates surrounding market and rate reform occurring in many jurisdictions, the initiative creates an ongoing, safe platform for experts and industry leaders to present, sound out, and provide feedback on direction and innovation to support utility sector evolution.

The 51st State Perspectives Series is designed to provide additional thought-leadership on the electric industry evolution happening across the nation. This first paper in the series compares the similarities and differences between the ongoing DER integration regulations, policies, and technical challenges in two drastically different states - California and New York. Other states may be able to draw from the spectrum of approaches as they consider options.

We hope that the 51st State Perspectives Series will encourage continued collaboration, productive dialogue, and idea sharing among electric industry stakeholders.

Introduction

Over the last century, the U.S. electric power sector has undergone significant changes in response to developments in technology, markets, regulations, and policies. The sector is once again entering a period of major change with the rise of DERs. These changes impact the electricity system to varying degrees across the country. New York and California have taken particularly proactive approaches to integrate DERs.

The New York and California approaches to DERs differ in several ways; however, their experiences in integrating DERs from the regulatory, technology, and policy standpoints provide critical lessons for other states. Notably, the two states are beginning their DER efforts under different conditions. California already has high penetrations of DERs, including nearly 600,000 residential photovoltaic (PV) installations,[1] and the state also has mandates for additional resources, such as storage. Meanwhile, in New York, DER penetration is significantly less with approximately 58,000 residential PV installations.[2] However, the New York governor and the Public Service Commission (PSC) have taken the view that DERs are critical to the energy future of the state and are creating a policy and regulatory framework to further DER proliferation. Another important distinction between the states is their existing infrastructure: California has a fully deployed, advanced metering infrastructure (AMI), while New York is just beginning AMI deployment. This has important implications for data sharing and visibility, as well as distribution system planning and the involvement of stakeholders in that process.

This paper considers myriad topics pertinent to the integration of DERs and how they are treated by the two states. It will begin with the goals of the two initiatives and how they are being realized through legislation and/or regulation. It will then explore the following topics and how the two jurisdictions treat them:

- Goals for DER Integration
- Interconnection
- Hosting Capacity
- Planning
- Benefit-Cost Analysis
- Data Sharing
- Use of Demonstration Projects
- Rate Reform and Utility Incentives
- ISO Interface

This first paper in the 51st State Perspectives series presents progress in DER integration in New York and California as of fall 2016. The hope is this discussion furthers understanding of key aspects of the integration of DERs and provides valuable lessons for the states to follow as these issues are evolving quickly.

1 GTM Research and SEIA, US Solar Market Insight, Full Report, Q3 2016.

2 Ibid.

TABLE 1: KEY ELEMENTS OF GRID TRANSFORMATION IN NEW YORK AND CALIFORNIA

DER APPROACH	NEW YORK	CALIFORNIA
INTERCONNECTION	Facilitate interconnection of DERs through streamlined process	Facilitate interconnection of DERs; help provide DER providers cost certainty
HOSTING CAPACITY	Preliminary analysis based on minimum loadings and equipment ratings. Joint utility processes to expand	Utility-specific capacity analysis as part of Distribution Resources Plan (DRP) filings
PLANNING	Focus on more granular forecasting, probabilistic planning, and implementation of NWAs	Focus on more granular forecasting, enhanced planning, and analysis to facilitate DER integration. Pilot programs to use DERs to offset utility Capex
BENEFIT-COST ANALYSIS	Benefit-cost framework based on the Societal Cost Test (SCT) approved. Utilities have filed Benefit-Cost Analysis (BCA) handbooks in their Distributed System Implementation Plans (DSIPs)	Initial focus is on locational valuation. California considering SCT as a possible method to capture system-wide benefits and costs. Utilities have filed Locational Net Benefits Analyses (LNBAs) in their Distribution Resources Plans (DRPs)
DATA SHARING	Focus on both customer and system data. System data to be provided to facilitate DER planning and interconnection	Primarily focuses on system data for the same reasons as New York. DRPs also outline data needed from DER providers
USE OF DEMONSTRATION PROJECTS	Establishes criteria for demos; focuses on business models and technical pilots	Demos required to pilot methodologies outlined in DRPs
RATE REFORM AND UTILITY INCENTIVES	Proposed rate reform through Track Two; changes manifested both in rate cases and separate proceedings	Successor to net energy metering (NEM) established; separate proceedings focused on aligning utility incentives to implement DERs
ISO INTERFACE	Roadmap going through stakeholder process to further integrate dispatchable DERs into wholesale market	Allows third parties to aggregate and bid dispatchable and non-dispatchable DERs into the wholesale market

Source: SEPA and ScottMadden, 2016

Goals for DER Integration

The two states set out similar goals related to the integration of DERs, and their stated objectives contain much overlap. In New York, the approach to integrate DERs is largely driven by interlocking PSC proceedings that reach across myriad issues and initiatives, including the evolution of net metering, low income proceedings, AMI, and energy efficiency. In California, a mix of commission and legislative DER initiatives, implemented with utilities' general rate cases (GRC), provides the primary approval mechanism for plans outlined by the utilities. California has proceeded with distinct initiatives and pilots combining legislative and Public Utility Commission (PUC) mandates, while New York has pursued a varied and complex set of initiatives all under the moniker of REV (Reforming the Energy Vision), under the direction of the PSC.

NEW YORK

In New York, the REV proceeding, which was initiated in April 2014, is the set of linked proceedings focused on the integration of DERs. It has six stated goals:[3]

1. Enhance customer knowledge and tools that support effective management of the total energy bill
2. Increase market animation and leverage of customer contributions
3. Improve system-wide efficiency
4. Implement fuel and resource diversity
5. Increase system reliability and resiliency
6. Reduce carbon emissions

> The NY PSC envisions that "REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources."

REV includes multiple proceedings implemented in three main tracks to accomplish the stated goals:

- **Track One** (Order[4] issued February 26, 2015) establishes the framework for development of the Distribution System Platform (DSP), which is divided into three categories: integrated system planning, grid operations, and market operations. The utilities' individual initial Distributed System Implementation Plans (DSIPs) and the jointly developed Supplemental DSIP, were filed in June and November 2016, respectively, to meet one of the requirements of the order.
- **Track Two** (Order[5] issued May 19, 2016) aims to modernize the utility business model and align utility financial interests with consumer interests—a gradual shift from the cost-of-service model to one that adds market-based platform earnings and outcome-based earnings opportunities.
- **Track Three** (Order[6] issued August 1, 2016) adopts a Clean Energy Standard (CES) that expands the Renewable Portfolio Standard (RPS) and aligns with the State Energy Plan (SEP) goal of 50% of energy generated from renewable sources by 2030 while retaining existing carbon-free generation.

3 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order).

4 Ibid.

5 REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016).

6 Case 15-E-0302, *In the Matter of the Implementation of a Large-Scale Renewable Program and Clean Energy Standard*, Order Adopting a Clean Energy Standard (issued August 1, 2016).

The New York utilities were required to include the following in their DSIPs:

- Plans for enhanced Distribution System Planning, including forecasting, capital budgeting, hosting capacity, probabilistic planning, and beneficial locations for DER deployment
- Protocols for operating the grid safely, reliably, and in a cyber-secure manner, in an environment with greater DER deployment
- Plans for the rollout of AMI
- Implementation plans for customer data sharing with DER providers and Energy Service Companies (ESCOs)
- Jointly developed handbooks for performing Benefit-Cost Analyses

Importantly, New York took the position in Track One that the utility will perform the role of the DSP provider. This formally continues the utility's role in planning and operations as opposed to allowing other parties to perform this role (or parts of it). In addition, the proceeding emphasized the evolution to a distribution-level market.

CALIFORNIA

California's goals and objectives for DERs have grown over the years from meeting its ambitious climate goals to a more implementation-driven approach and a focus on proactive planning for DER integration. The state has some of the most ambitious legislation and standards to spur DER growth, and it requires utilities, electric service providers, and community choice aggregators to increase the procurement and integration of renewable energy resources and DERs.

The overarching goals of the DER legislation passed to date are to:

1. Drive innovations in products and services offered by utilities.
2. Provide outstanding reliability and power quality in the evolving interconnected electric grid.
3. Increase/maintain affordability to avoid undue burden on all stakeholders.
4. Reduce emissions and demonstrate environmental responsibility.
5. Increase grid reliability, resilience, and efficiency.
6. Ensure the continued safety for customers, employees, and the public.
7. Provide robust security—both physical and cyber.

Numerous legislative and regulatory measures reflect these goals:

- The Clean Energy Plan (CEP) set a goal of installing 20,000 MW of renewable electricity by 2020.[7]
- The RPS dictates 50% of all energy procured must be from renewable sources by 2030.[8]
- The Clean Energy Jobs Plan (CEJP) has a specific target of 12,000 MW of distributed generation (DG) to spur investment in renewable energy to create and keep local jobs.[9]
- Assembly Bill 327 (AB 327) implements and extends programs that impact the Net Energy Metering (NEM) program,[10] extends the state's RPS, restructures residential rate design, and requires Distribution Resources Plans (DRPs) for major investor-owned utilities (IOUs). DRP requirements were outlined in Rulemaking 14-08-013.[11]

7 Office of Ratepayer Advocates. http://www.ora.ca.gov/der.aspx

8 CPUC. Senate Bill 350. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

9 Office of Ratepayer Advocates. http://www.ora.ca.gov/der.aspx

10 CPUC. AB 327 Section 9a. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

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

The California DRPs required the following:

- Analyses of distribution planning (Integrated Capacity Analysis, Locational Net Benefits Methodology, and DER penetration scenario analysis)
- Proposals for demonstration projects to validate and refine distribution planning analyses
- Proposals for bi-directional data sharing between utilities and third parties
- Identification of relevant tariffs and contracts and proposals for modification
- Review of relevant safety considerations of greater DER penetration
- Identification and categorization of barriers to greater DER penetration
- Identification of required utility investments
- Coordination of utility distribution planning with:
    - California Energy Commission's (CEC) Integrated Energy Policy Report
    - California Public Utilities Commission's (CPUC) Long Term Procurement Plan
    - California ISO's (CAISO) Transmission Planning Process
- Proposals for a phased rollout of required projects and processes

- The Integrated Demand-Side Resource (IDSR) proceeding (D.07-10-032) seeks to create mechanisms to source, integrate, and incentivize the adoption of cost-effective DERs to meet the needs of the utilities.[12]
- Energy storage bills (AB 1637, AB 2868, AB 2861, and AB 33) focus on expanding the role energy storage plays, providing tools to integrate renewables, and giving customers more ways to manage energy costs while ensuring grid reliability.[13]

These are a number of the DER initiatives being pursued in California; some also articulate discrete goals for the specific rulemaking or order.

IN SUMMARY

While many of their goals overlap, New York and California are using different mechanisms to achieve those goals. New York has put together its set of REV proceedings that focus primarily on DERs; California has various legislative and regulatory mechanisms advancing many "green" initiatives.

KEY SIMILARITIES	KEY DIFFERENCES
▪ Both seek to increase DER penetration ▪ Both have environmental or greenhouse gas reduction goals	▪ New York places all DER-related initiatives, as well as several others, under REV and the PSC drives these initiatives ▪ California has various regulatory and legislative initiatives; many impact both DERs and other renewables and storage

12 Girouard, Coley. "Distribution Planning in a Distributed Energy Future." Advanced Energy Economy. April 28, 2016. http://blog.aee.net/distribution-planning-in-a-distributed-energy-future; http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M154/K464/154464227.PDF

13 Burger, Andrew. "California Ramps Up Energy Storage Plans with Enactment of Four New Bills." Renewable Energy World. September 28, 2016. http://www.renewableenergyworld.com/articles/2016/09/california-ramps-up-energy-storage-plans-with-enactment-of-four-new-bills.html

Interconnection

New York and California have made advances in the interconnection process through different means. The increased efficiency of interconnection and management of costs are critical to the integration of DERs (particularly rooftop solar) and are closely tied to both states' initiatives related to data sharing and hosting capacity analysis.

NEW YORK

In New York, the REV proceedings seek to reduce the barriers to interconnection for DG by better managing the increasing volume of applications. Two orders are driving improvements to the interconnection process, the Track One Order and the *Order Modifying the Standardized Interconnection Requirements* (SIR).[14] The Track One Order outlined nine requirements utilities must meet in the Interconnection Online Application Portal (IOAP) to facilitate interconnection applications by developers and customers.

The IOAP provides applicants with a tool to submit standardized forms and interconnection applications and track the status of applications during evaluation. In addition to the IOAP, the Order Modifying the SIR changed the technical details and process for DG interconnection. It also placed timeliness requirements not only on the utilities, but also on the applicants. This should force applications to progress toward actual projects or clear the way for other viable projects later in the queue. The SIR revisions became effective April 29, 2016, and the utilities reported progress against the Track One Order requirements in their initial DSIP filings in June.

In addition to the Track One Order, Track Two identified potential earnings opportunities associated with improvements to the interconnection process beginning in 2017. The focus is on improved timeliness, satisfaction, and completed applications as indicated by DER providers. Achieving successful high marks in these areas presents a positive earning opportunity for utilities, and exceptional cases of inadequate effort or performance could mean a negative earnings adjustment.

CALIFORNIA

California set a standard for defining how DERs connect to the grid with the passage of Electric Tariff Rule 21;[15] the California Public Utility Commission (CPUC) finalized updates to Rule 21 in March 2016. The CPUC decision provides more transparency for DER developers connecting to the grid and limits their cost overrun liabilities, but only for DG projects that aren't subject to net metering. The decision requires utilities to develop a Unit Cost Guide to give developers a price list for typical interconnections and make costs clear upfront for interconnection applicants. With this increased cost transparency, developers can make decisions on where to install DG on the grid, limiting costly infrastructure upgrades.

This update initiates a five-year pilot program that caps a developer's liability to within a 25% "cost envelope" of the utility's original estimate. If the interconnection process ends up costing more than 125% of the estimate, ratepayers cover the excess for the utility.

IN SUMMARY

Integrating DERs requires improved interconnection into the grid. Both New York and California are seeking to improve the interconnection process by providing transparency for DER developers and

14 Case 15-E-0557, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less*, Order Modifying the Standardized Interconnection Requirements (issued March 17, 2016).

15 New California Interconnection Ruling Increases Transparency and Limits Costs; Julian Spector, GTM, June 24, 2016.

increasing the efficiency of the application process. New York has taken one step further in establishing incentives for utility performance in executing the process.

KEY SIMILARITIES	KEY DIFFERENCES
▪ Focus on interconnection process and making the process easier for developers and customers	▪ In New York, development of a standard portal ▪ New York is tying utility earnings to successful execution of process improvements

Hosting Capacity

Hosting capacity is defined as the amount of DERs that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line voltage and/or secondary network system.[16] As such, hosting capacity is a critical element of the interconnection process. Both states are actively pursuing enhanced hosting capacity analysis that will ultimately need to consider the changing configuration and loading of distribution-level feeders and equipment.

NEW YORK

The work to develop an agreed hosting capacity methodology is underway by the joint utilities (JU).[17] As a first step, many of New York's utilities have offered red-zone maps showing hosting capacity based on two inputs: minimum loading and the rating of local distribution assets. These inputs yield a static view indicating the hosting capacity of the largest allowable DG producing at maximum output, without violating back-feed requirements.

A representative example would be a PV unit, operating at 10AM on a temperate March weekend, where the DG output is high relative to the loading. Under these worst-case conditions, the PV could only be sized to the available hosting capacity based on the limiting factors of the minimum local load, the maximum output of the DG, and the capacity of the local distribution assets.

More refined hosting capacity calculations will consider more inputs and include the dynamic nature of these inputs (and of the distribution grid in general). For example, AVANGRID's flexible interconnect capacity solution (FICS) demonstration project is allowing larger DGs to interconnect than could otherwise be accommodated in exchange for the ability to selectively curtail participation in times of system need (e.g., ramping down the generator during times of low load).

The JU continue to work on a common methodology to expand hosting capacity analysis. The supplemental DSIP included the graphic and timeline in Figure 1.

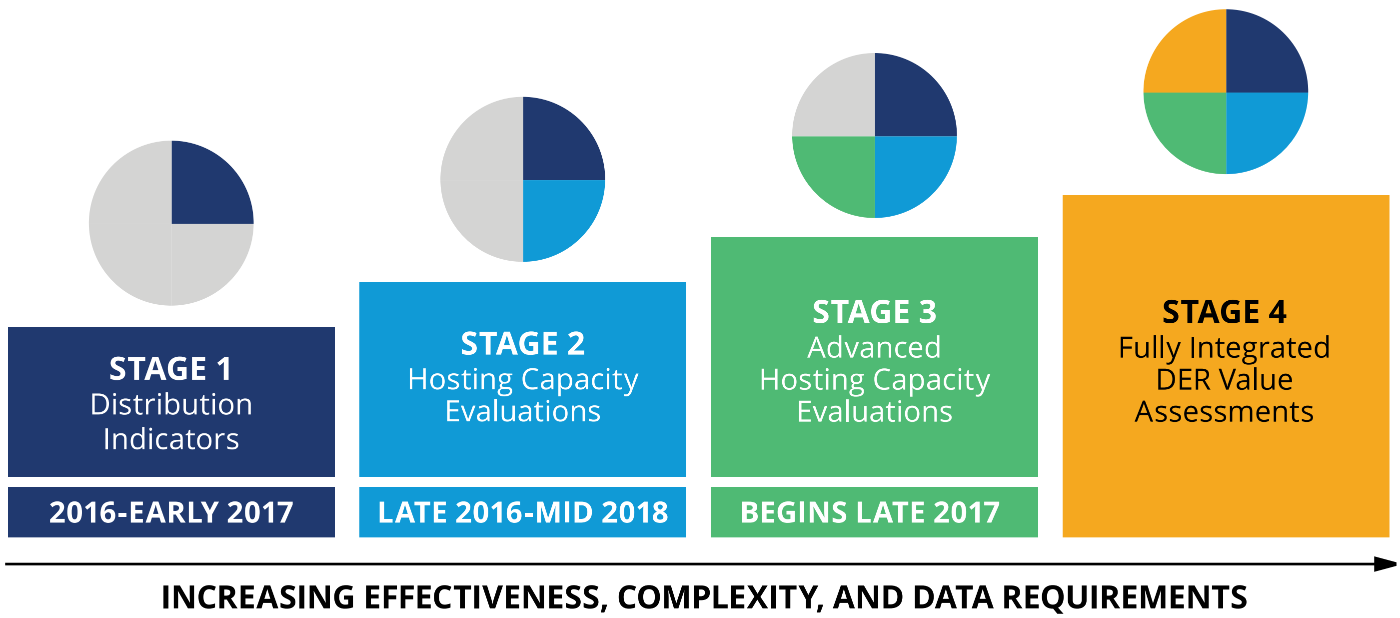
CALIFORNIA

As part of their DRP submissions in July 2015, California's utilities evaluated each circuit segment to determine the maximum amount of DERs that could connect to existing electric systems while

16 Electric Power Research Institute, *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, Report Number 3002008848, June 2016, p.2.

17 The Joint Utilities are comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

FIGURE 1: JOINT UTILITIES HOSTING CAPACITY ROADMAP



Source: Joint Utilities of New York, Supplemental Distributed System Implementation Plans (SDSIP) Final, 2016[18]

adhering to the stated constraints. Following CPUC guidance, the utilities collaborated to develop a common set of constraints for integration capacity. As such, the distribution system:

- Is designed to operate below equipment thermal limits
- Should maintain voltage within acceptable bounds
- Should avoid compromising protection schemes
- Must function safely and reliably

In developing this analysis, the utilities' approaches varied from a sampling of their distribution system to the analysis of each individual circuit. Southern California Edison (SCE) analyzed a set of representative feeders and extrapolated the results across its entire service territory. In contrast, Pacific Gas and Electric (PG&E) studied each circuit across its distribution system. Due to the localized nature of DERs and their impacts, it is likely that future analysis will require the assessment of each individual circuit throughout the system. In addition, there are plans to extend the set of evaluated criteria and include an assessment of hosting capacity during expected switching operations and abnormal conditions. The utilities have not yet received feedback on the DRPs submitted last year, so it is not clear the degree to which the approaches outlined above will be acceptable to the CPUC.

IN SUMMARY

Connecting DERs to the grid requires not only increased transparency into costs and the application process, but also an increased emphasis on understanding the impacts on the grid when deploying DERs. In both states, regulators are working with the utilities to ensure planning efforts include more refined analysis and technical solutions to ensure hosting capacity is available. The state is also driving utilities to provide increased transparency about where capacity concerns could limit DER deployment. The DRPs in California and the DSIPs in New York are the first attempts to provide clarity and transparency into hosting capacity, and these efforts are continuing to evolve.

18 http://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf

KEY SIMILARITIES	KEY DIFFERENCES
▪ Both jurisdictions working toward more granular analyses	▪ In New York, the JU process is leading toward a common methodology ▪ California's utilities have taken different approaches to date; not yet clear whether they will converge

Planning

The distribution system planning process has traditionally focused on delivery of electric service to customers. Load forecasts that formed the basis of projected loading on distribution equipment anticipated the effects of energy efficiency and demand response programs only at the system level, if at all. With the emergence of different types of DERs, utilities must now include DERs into more granular forecasts and develop infrastructure plans to manage the impact of these resources on operations and safety. In addition to more granular planning, utilities must now integrate myriad scenarios into their planning processes, and in New York, they are looking to a probabilistic versus a deterministic planning process. Lastly, there is a move to consider the use of DERs to offset traditional transmission and distribution (T&D) capital infrastructure. The industry is moving to "transmission-like" planning, but with many more assets, sources, and sinks.

NEW YORK

To date, forecasting has typically included DERs (specifically energy efficiency and demand response) only at the system level and typically as load modifiers. The recent Supplemental DSIP filing discussed the need to move utilities to more granular forecasts to address the emergence of DERs and better inform distribution capital infrastructure planning.

In the DSIP Order,[19] the PSC directed the utilities to develop "an approach to move toward probabilistic planning as DER penetration increases."[20] This stands in contrast to the traditional deterministic utility planning models, where contingency scenarios are modeled by removing the most critical component(s) and ensuring operation can continue. For instance, in an n-2 design, the system would be designed to withstand the removal of the two most critical components. This shift to probabilistic planning models is critical because:

- DERs are generally beyond direct utility control.
- DERs will be numerous and dispersed across the system.
- Different types of DERs have different operating characteristics (e.g., intermittent solar vs. the dispatched operation of a battery).

When considering the substitution of DER solutions for traditional grid projects, utility planners must be able to compare the reliability of the solutions on an equivalent basis. This is not possible using a deterministic model, because the impact of removing the two largest DERs will vary depending on the number of other DERs in the area and the reliability with which they are providing grid support.

19 REV Proceeding, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016).

20 REV Proceeding, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), p. 13.

The most prominent example of an NWA is Con Edison's Brooklyn Queens Demand Management (BQDM) program. In this program, two substations and sub-transmission feeders, needed to address local load growth in the Brooklyn network, were deferred through 2026 through a combination of 41 MW of customer-sited solutions, 11 MW of non-traditional utility solutions, and 6 MW of traditional utility solutions. The cost of the non-traditional solutions totals $250M, which offsets the $1B substation build from 2018 to 2026. Using BQDM as a prototype, the PSC required each utility to propose NWA project candidates as part of the Track One Order and to highlight additional needs in their DSIP filings.

For instance, removing two of three similarly-sized DERs would have a greater impact than removing two of one hundred similarly sized DERs. Similarly, many small units (e.g., 10 x 100 kW) that perform with 99.99% reliability would be preferable to one large unit (e.g., 1 x 1 MW) that performs with the same reliability.

To accurately compare a DER solution to traditional infrastructure, probabilistic modeling must be developed for both DERs and traditional solutions. The supplemental DSIP, filed by the JU on November 1, 2016, outlines the next steps in advancing discussions in probabilistic planning.

As one of the drivers of the REV proceeding, in its Track One Order, the PSC cites an expected $30B of capital spending on infrastructure over the next decade (versus $17B in the previous decade) to replace aging infrastructure.[21] When combined with limited load growth, the existing assets must be utilized more efficiently to mitigate significant impacts to ratepayers. Targeted cost-effective deployment of DERs may offer more incremental capacity that can defer larger traditional infrastructure build-out. The development of NWAs has become a focus of REV, and New York utilities have proposed several.

CALIFORNIA

Similar to the direction of the supplemental DSIP in New York, the California DRP filings addressed coordination between utilities and the California Energy Commission (CEC) load forecasting. The utilities are expected to develop more granular and accurate forecasts of the impacts of DERs on load. Also, utilities are expected to outline how these changes will impact their internal and external load forecasting.

Through the DRP process, the CPUC required each utility to provide scenario-based planning and quantitative integration analyses to support their DER integration plans. Not all locations within a utility's territory have the same hosting capacity or have the same need (or value) for increased DERs. To address this issue, they were required to identify the existing and near-term capacity of their distribution systems, conduct an optimal location benefit analysis for the future implementation of DERs, and conduct 10-year high, medium, and low DER growth scenarios. Through these requirements, the utilities identified needed distribution infrastructure enhancements, the locations where they could maximize the net benefit for DER growth, and how the long-term growth scenarios may affect distribution planning.

A pilot under development in California will explore the development of NWAs (though this term is not used). In April 2016, the CPUC issued the *Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources*. This order seeks to develop a process by which utilities can propose DERs to offset traditional capital investment while providing appropriate incentives for them to undertake these projects.

21 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order), p. 17.

IN SUMMARY

Both jurisdictions are enhancing forecasting and distribution planning processes to better account for DERs in load forecasting and to identify upgrades to the system necessitated by DERs. In addition, both New York and California are looking at the use of DERs as an alternative to traditional capex, potentially reducing the cost to customers. In New York, DSIPs identified potential NWAs, subject to approval, through discrete filings. California is using the above pilot approach to create incentives. Important findings will come from each approach, but New York appears to lead in terms of project development now.

KEY SIMILARITIES	KEY DIFFERENCES
▪ Move to increase the granularity of forecasting ▪ Increasing focus on NWAs	▪ Implementation of probabilistic planning in New York vs. scenario planning at various DER penetrations in California ▪ In New York, NWAs identified as part of DSIPs require regulatory filings to establish incentives and rate treatments ▪ In California, pilot programs will address NWA implementation, including incentives

Benefit-Cost Analysis

BCA is key to assessing whether DERs are a preferable cost-effective alternative to traditional distribution infrastructure investments. The benefit-cost analytical processes in New York and California are very similar in purpose. Both attempt to build transparent, consistent methodologies to appropriately recognize and value DERs to offset traditional utility investments in distribution infrastructures.

In general, both methodologies employ common elements: avoided generation capacity, avoided T&D capital expenditures and operations and maintenance (O&M), avoided energy, avoided ancillary services, and societal benefits (see table in Appendix).

NEW YORK

In New York, the JU developed a BCA handbook, based on the framework provided by the Commission, but each utility has its own inputs to the analysis provided in the handbooks filed with the DSIPs. The basic evaluation approach underpinning the methodology is an avoided cost framework reminiscent of historical energy efficiency valuations. New York uses the Societal Cost Test (SCT) as the primary cost-effectiveness measure. The SCT recognizes the benefits to society as a whole if DERs are substituted for utility investment, explicitly accounting for externalities and social out-of-market costs and their impacts on society as a whole. The utilities can supplement their respective analyses with other cost-effectiveness tests, such as the Utility Cost Test (UCT) and the Rate Impact Measure (RIM), but the SCT is the primary measure of cost effectiveness.

There are four types of costs explicitly considered in New York's BCA framework:

- Program Administration Costs (PACs) to start and maintain a specific program
- Utility-related costs, such as lost revenues and shareholder incentives
- Participant-related costs to achieve program objectives
- The cost of externalities

The framework adopted in New York captures some DER integration costs (within the Added Ancillary Service Cost category). The approach in New York is explicitly adapted to add rigor for valuing distribution-level value components with more locational and temporal granularity.

The JU in the Supplemental DSIP noted that assessing locational value of DERs would be better addressed through an analysis of constraints first (see Figure 1 in Hosting Capacity section) and, as such, have flagged fully integrated locational value assessments as an area to address in a step-by-step fashion as tools, models, and processes evolve in these capabilities.

CALIFORNIA

The process to arrive at a framework for evaluating the benefits of DERs in California is less linear than in New York.

Within the Integrated Distributed Energy Resources (IDER) proceeding, the CPUC recently embarked on an effort to compare all the tests for cost effectiveness historically employed for various DERs: Total Resource Cost (TRC), Program Administration Cost (PAC), RIM, Participant Cost Test (PCT), and SCT. The differences in cost tests were due to resource and technology types in some cases, and in others, the consequence of policy goals, timing, or the preference of decision makers. The process examined opportunities to reconcile approaches where appropriate. The CPUC is also considering changing the primary cost test for consistent use across all DER proceedings with consideration given to the SCT.

California's approach is also explicitly adapted to add rigor for valuing more localized, granular distribution level components, notably through the locational net benefits analysis (LNBA) process. The purpose of the LNBA is to identify optimal locations of DER deployment that reveal, via distribution system heat maps, the relative value of deferral opportunities for capacity constraints.

California has not yet determined how all of these pieces would work in tandem, but the LNBA would likely provide insights into areas of value. The components capturing locational value from the LNBA would transfer to the benefit calculations within the SCT or a framework that captures both locational and system-wide values.

Both valuation approaches aim to balance standardization and uniformity in BCA and reporting with flexibility to accommodate utility-specific distinctions. As such, in California, the IOUs filed their own LNBA approaches for their respective Demonstration B projects (see section below on Demonstration Projects), where the analyses will initially be tested.

Both New York and California designed evaluations to inform new tariff development for DER compensation, earnings mechanisms for utilities, and DER solicitation and procurement processes.

KEY SIMILARITIES	KEY DIFFERENCES
▪ Benefit-cost frameworks contain similar elements (avoided generation capacity, avoided T&D capital expenditures and O&M, avoided energy, avoided ancillary services, and societal benefits) ▪ Analyses initially applied to demonstration projects ▪ Flexibility to account for utility-specific issues ▪ Locational and temporal specificity and granularity	▪ New York has approved the SCT as the primary measure for the cost effectiveness of DERs. California is considering the SCT ▪ In determining the benefits of DERs, California is initially focusing on valuing benefits with locational granularity with provisioning of maps that highlight relative value. In New York, the JU have flagged locational value as an area to address after analyzing hosting capacity constraints

Data Sharing

Sharing of system data among utilities, customers, and third parties is a critical element to increasing DER penetration. To that end, both New York and California have established requirements for data sharing and are engaging stakeholders to advance those discussions.

NEW YORK

Data sharing discussions are evolving in two separate tracks. First, there is a move to share more customer data with third parties. Second, efforts are underway (as illustrated by the DSIPs and SDSIP) to make more system data available.

In the sharing of customer data, the goal is to enable third parties (Energy Service Company [ESCOs] or others) to use the data to identify potential service offerings for customers so that they may better manage their energy use or benefit from specific DER products. New York has had two demonstration pilots that developed a marketplace where customers could elect to share their usage information with third-party companies to receive special offers for products. This would include time-stamped energy usage information to be used to develop business cases and quickly develop market-based DER products and services.[22] The sharing of customer data raises privacy concerns, and many utilities proposed the use of Green Button Connect as a secure mechanism for customers to share their usage data with authorized vendors.

The sharing of system data is closely related to hosting capacity and distribution planning discussions. System data helps developers identify the most beneficial (and profitable) places on the grid to connect DERs (including hosting capacity data). This data also enables them to provide DERs in response to solicitations issued to address NWAs (see sidebar on Con Edison's BQDM).

In June 2016, the New York utilities were directed to file hourly forecast system data and plans to improve the collection and sharing of system data in their individual DSIPs. The filings reflect the various stages of data collection and hourly forecasting capabilities across New York. Responses ranged from providing historical loading data to "synthesizing" forecast

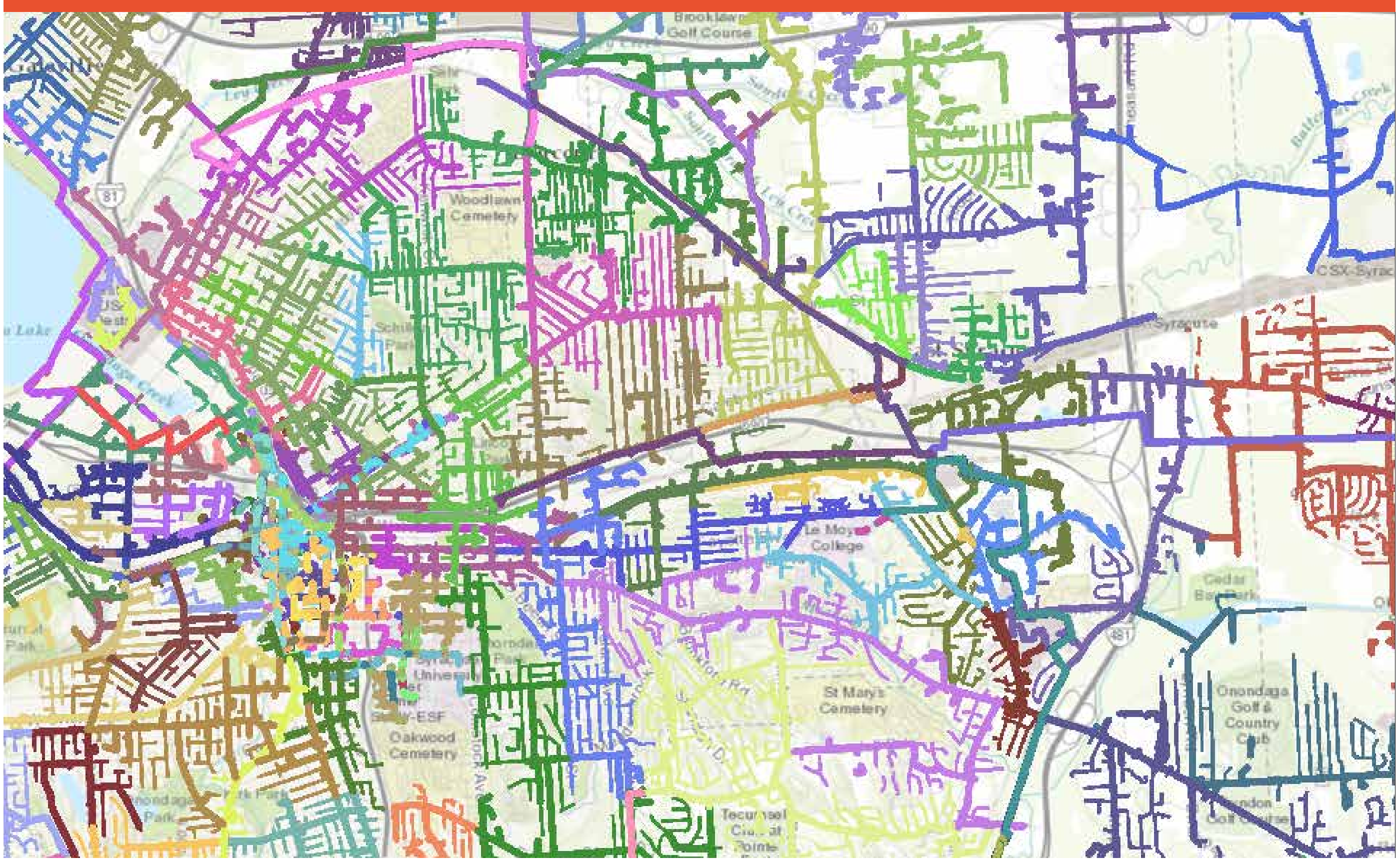
22 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order), pp. 53-54.

data based on extrapolating load data, to providing circuit-level system data. The most notable example filed in a utility's DSIPs was National Grid's system data landing page (shown in Figure 2).

Utilities will also provide system data for NWAs, where DER solutions are assessed as an alternative to traditional utility infrastructure. Utilities must define the boundaries of the areas that benefit, the type of need (capacity, voltage support, etc.), the hours of need, the date by which the solution must be in place, and any applicable load curve data that would help the market bring DER solutions to bear. A consistent format across the utilities will help bring solutions online more efficiently as DER providers become more familiar with the process. The Supplemental DSIP filing more fully addresses this issue.

The distinction between basic data and value-added data is an ongoing discussion in New York. In its Track One Order, the PSC commented that, "The DSP will also provide or sell a set of products and services to customers and service providers. Those might include transaction or usage fees, platform access, analytic services, interconnection services, pricing and billing, metering information services and data sharing, and DER maintenance, operation, and financing."[23] The PSC reinforced this notion in the Track Two Order citing, "Charges may be

FIGURE 2: NATIONAL GRID'S SYSTEM DATA PORTAL CALLING OUT SPECIFIC FEEDER INFORMATION



Source: National Grid, 2016[24]

23 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order), p. 34

24 http://ngrid.maps.arcgis.com/apps/MapSeries/index.html?appid=4c8cfd75800b469abb8febca4d5dab59&folderid=8ffa8a74bf834613a04c19a68eefb43b.

assessed by utilities for information beyond basic customer data."[25] Determining what information can be provided and at what price will shape an important part of the new utility business models, and the Supplemental DSIP filing further explores these issues.

CALIFORNIA

California is leading the push for data sharing, which is made easier by the rollout of AMI. Like New York, California is also using data-sharing tools, such as Green Button Connect, to make customer data available. Pursuant to the Smart Grid Proceeding (R.08-12-009), data access procedures will be modeled on customer privacy and other information security standards, and expedited data release procedures were approved by the Commission in D.11-07-056 (customer energy usage data privacy), D.13-09-025 (Customer Data Access), and D.14-05-016 (Energy Data Center). The rules, written in response to those decisions, describe the specifics concerning data sharing: what data is available, who can access it, how often it is refreshed, what fees apply, and how the privacy of the data is protected. These data access procedures will facilitate insights into customer energy usage, including what grid services customers value, and how to market DER products based on more granular usage information.

Regarding system data, the DRPs submitted by PG&E, SCE, and SDG&E have provided insights into the utilities' data-sharing plans. These utilities have created circuit-level DER interconnection mapping tools, which grant third-party providers a deeper view into the parts of the grid open to new solar systems, behind-the-meter energy storage, electric-vehicle chargers, and other distributed energy systems. PG&E's Renewable Auction Mechanism (RAM) map is one example. This web-based map can be used to help customers identify potential interconnection project locations. Customers can identify selected electric transmission lines, distribution lines, and substations on this map, as well as operating voltages, line capacity, and substation names.

One of the distinctive elements of the California proceeding is the provision of locational value maps. In addition to maps that geographically display hosting capacity, California requires that utilities provide heat maps of potential optimal locations for DER placement on the distribution system using the LNBA methodology. Utilities must align these heat maps to the Distribution Planning Areas (DPAs) in the Demonstration B projects (see Demonstration Projects section below) to inform DER providers, developers, and stakeholders of DER locations of greatest value to the grid. California will also use heat maps for prioritization of Capex deferral opportunities through the use of DERs.

In the future, the utilities will grant access to distribution feeder-specific distribution planning data, such as the data generated by the Integration Capacity (IC) and LNBA. IC Analysis data is a quantity/result provided in units of DER nameplate real power that specifies how much of a specific DER can connect to a specified zone on the distribution system. Web-based platforms of this data will provide convenient continuous access to customers, developers, and the public.

IN SUMMARY

Data sharing between utilities, customers, and third parties is critical to the continued integration of DERs. Access by third parties to system and customer data provides those parties the opportunity to actively participate in deploying NWAs, to identify the most beneficial (and least costly) part of the grid in which to install DERs, and to develop products and services that are of most interest to utility customers. Meanwhile, utilities are leveraging demonstration projects as small-scale test-beds to evaluate concepts and processes related to interconnection, hosting capacity, and data-sharing capabilities.

25 REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p. 140.

KEY SIMILARITIES	KEY DIFFERENCES
▪ Move to increased sharing of customer and distribution system data ▪ Implementation of Green Button Connect	▪ Integration of value-based analysis in California; availability to developers through maps ▪ New York maps still in early stage development and contain much less information ▪ Focus on retail customer data in New York (due to nascent AMI implementation)

Use of Demonstration Projects

Demonstration projects afford utilities the opportunity to introduce concepts to improve the integration of DERs (technology and process) on a small scale. These demonstration projects allow for testing concepts with limited risk to the system and stakeholders. In some cases, these demonstrations or pilots are recoverable through rates, minimizing financial risk to the utility. Both states have deployed numerous demonstration projects. More are under development to test technical solutions, integrate greater numbers of DERs, and illustrate alternative business models made available through DER solutions.

NEW YORK

The New York PSC recognized that the transformative nature of the REV proceeding required an iterative, phased approach. To validate DER-related market services to be provided through the DSP, the PSC included a mandate for demonstration projects as part of its Track One Order. These demonstration projects inform

The utilities are to partner with third party technology providers and propose projects that meet the following nine 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 expense between rate-base and competitive markets
4. A competitive market for grid services, with the utility owning DER 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

DSP functionality, measure customer response to programs and prices associated with REV markets, and determine the most effective implementation of DERs. These projects are also a means of presenting REV to the customer and gauging their receptiveness to new technologies, products, and services.[26]

So long as they align with the criteria, utilities have the flexibility to propose projects to explore different technologies and business models, subject to evaluation by the Department of Public Service Staff (DPSS) and approval by the PSC. To date, New York utilities have filed 13 demonstration projects.[27] These cover a wide range of topics from Con Edison's Virtual Power Plant, which bundles solar with storage to test the demand for premium resiliency services, to Orange & Rockland's Customer Engagement and Marketplace Platform (CEMP), which offers customers products they can use to manage their energy usage.

New York expects utilities will continue to file demonstration projects. To facilitate the pipeline of project proposals, the New York State Energy Research and Development Authority (NYSERDA) established a portal, dubbed REV Connect, that will grade and screen market proposals to assist the utilities in project selection.

CALIFORNIA

The CPUC mandated that the DRPs produced by the utilities include demonstration projects to prove the feasibility of the utilities' enhanced distribution planning methodologies before applying those methodologies on a system-wide basis.

The pilot projects seek to overcome barriers related to DER integration and advance DER penetration. Guidelines for California's demonstration projects included:

- Demonstrating integration of locational benefits analysis into utility distribution planning and operations
- Coordinating projects with ongoing utility Smart Grid deployment plans, where feasible
- Working closely with Load Serving Entities, third-party DER providers, and DER technology vendors through the design of these demonstration projects
- Paying attention to issues related to data exchange
- Including expected cost recovery for these demonstration projects

Utilities were required to include the following five types of demonstrations in the DRPs:

1. Demonstrate Dynamic Integrated Capacity Analysis (Demonstration Project A)
2. Demonstrate the Optimal Location Benefit Analysis Methodology (Demonstration Project B)
3. Demonstrate DER Locational Benefits (Demonstration Project C)
4. Demonstrate Distribution Operations at High Penetrations of DERs (Demonstration Project D)
5. Demonstrate DER Dispatch to Meet Reliability Needs (Demonstration Project E)

IN SUMMARY

Demonstration projects provide a testing ground for developing policy, alternative rate mechanisms, and new technologies without large-scale infrastructure investments. As DER integration moves forward, the expectation is that demonstration projects will continue to inform both technical integration and business model alternatives.

26 REV Proceeding, Memorandum and Resolution on Demonstration Projects (issued December 12, 2014), p. 1.

27 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

KEY SIMILARITIES	KEY DIFFERENCES
▪ Demonstration projects serve to prove concepts	▪ In New York, utilities are proposing demonstration projects that meet PSC's criteria and pilot both alternative business models and technical DER integration ▪ In California, utilities designed demonstrations specifically to prove concepts included in the DRPs

Rate Reform and Utility Incentives

DERs introduce significant regulatory challenges. New York and California have opted to take different approaches to these challenges, with New York focusing on gradually evolving the cost of service model and ultimately moving away from net metering. California has moved to "Net Metering 2.0," while piloting alternative earnings approaches through the IDER proceeding. To date, both have used traditional rate cases as the primary vehicle to implement these changes; however, in both states, various filings outside rate cases address utility incentives, NWAs, and earnings opportunities.

NEW YORK

Track Two of REV seeks to modernize the current rate structure to more closely align utility requirements with customer interests. To achieve the goals of REV, Track Two introduces gradual changes to the rate structure while avoiding an abrupt shift in traditional rate design. The Commission defined nine rate design principles[28] that guide the process. These principles include: cost causation, encouraging outcomes, policy transparency, decision making, fair value, customer orientation, stability, access, and gradualism.

With these guiding principles in mind, proposed modifications to the rate structure[29] include a demand charge, time-of-use (TOU) rates, smart home rates, improved commercial and industrial rates, and standby tariffs. Each modification is described briefly below:

- **Demand Charge**—In concert with volumetric-fixed customer charges, the incorporation of a demand charge during peak periods allows for the reduction of long-term infrastructure needs and optimal integration of DERs. Utilities are required to offer demand charges on an opt-in basis.
- **TOU Rates**—As a more accurate reflection of actual generation costs, TOU rates allow customers to participate in the reduction of overall system costs. The focus on the introduction of TOU rates should increase participation and allow assessment of their efficacy. Utilities are required to offer TOU rates on an opt-in basis.
- **Smart Home Rate**—A combination of the TOU rate and the eventual full implementation of the Value of DER (see below) potentially enables granular, time-based rates with value-based

28 https://www.energymarketers.com/Documents/NY_REV_Track_2_paper.pdf

29 https://www.energymarketers.com/Documents/NY_REV_Track_2_paper.pdf, pp 98-103.

compensation for DERs. Utilities will develop demonstration projects by February 2017.

- **Improved Commercial and Industrial (C&I) Rate**—Utilities must refine C&I rates to more accurately reflect peak and off-peak demand. Demand charges may be an appropriate method to shift behavior. Utilities are required to include modifications in their next rate filings.
- **Standby Tariffs**—Utilities were required to file revisions to their standby service tariffs in four areas:
  1. How to reward customers who provide overall system value;
  2. Changes to the allocation of contract and daily as-used demand charges;
  3. A distinction between new load and existing load, with a phase-out period for new load status; and
  4. A method to identify the marginal cost of service and then apply an add-on for non-capital related cost recovery. Revisions to the utilities' standby tariffs and updated standby rate allocation matrices were filed on August 1, 2016, and October 7, 2016, respectively.

Earning Adjustment Mechanisms (EAMs)[30] are new performance incentives oriented toward near-term measures to create customer savings and develop market-enabling tools. Initially, these mechanisms are only positive in nature, but the Commission may include negative adjustments in the future. The current maximum adjustment is 100 basis points. The following EAMs have been proposed:

- ***Interconnection***—Based on progress on the interconnection process and customer satisfaction
- ***System Efficiency***—Focused on peak demand reduction and load factor targets
- ***Energy Efficiency***—Based on targets proposed as part of the Clean Energy Advisory Council's (CEAC) efforts
- ***Customer Engagement***—Based on participation in TOU rates, Smart Home Rates, and other programs
- ***Clean Energy Standard***—Under development through a stakeholder process

EAMs are being proposed through collaborative JU and stakeholder processes, as well as in utility rate cases.

Platform Service Revenues (PSRs)[31] are opportunities for utilities to earn revenue from the growth and/or operation of market solutions beyond the traditional cost-of-service model. Approval for the product or service offering will consider whether:

- **(a)** The service is required as a part of market development
- **(b)** The services provide an additional value to the customer while closely tied to the utility's core business
- **(c)** The service cannot be more efficiently provided by a third-party
- **(d)** The utility is taking on an appropriate amount of risk with the project

Utilities must answer each of these questions when they file a new PSR; the answers will determine the degree in which utilities will share revenues with customers and shareholders. Utilities may file PSRs with the Commission outside of rate case proceedings.

The Value of DER Proceeding seeks to value the contribution DERs make to the grid for appropriate compensation. To that end, it is a successor to NEM.[32] On October 27, 2016, the PSC staff issued its Report and Recommendations in the Value of DER Proceeding. The report, which is the

30 REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p.53

31 REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p.40

32 Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources (Value of D Proceeding)*, Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference (issued December 23, 2015).

Scorecards[33] provide a way of tracking specific metrics reflecting the progress of REV implementation initiatives. While not currently monetized, utilities will track these metrics, which leaves the potential for monetization open. Utilities and their stakeholders continue to collaborate on scorecard metrics, and they currently include:

- System utilization and efficiency
- DER penetration
- TOU rate efficacy
- Market development
- Market-based revenues
- Carbon reduction
- Conversion of fossil-fueled end uses
- Customer satisfaction
- Customer enhancement

result of a stakeholder process initiated in early 2016, defines a proposed compensation methodology for DERs. It also lays out how the first phase of that methodology should apply to various categories of DERs in the near term and be implemented through tranches and triggers based on DER penetration specific to each utility. The recommendations contained in the report are a first step in moving beyond retail rate net-metering and toward an accurate valuation of all the benefits DERs provide. The report proposes a Phase One compensation methodology utilizing a value stack comprised of an Energy Value, Installed Capacity Value, Environmental Value, and Demand Reduction/Locational System Relief Values. The PSC is expected to issue the Phase One Order in January 2017.

CALIFORNIA

The CPUC has focused on modifying NEM with the goal of creating an environment for sustainable growth of customer-site renewable DG.

As part of the changes to NEM, California required utilities to move from four residential pricing tiers to two tiers by 2019. Under the four-tier structure, the Tier 4 rates ranged from 223% to 275% of the Tier 1 rates, depending on the utility.[34] In the two-tier structure created by the 2015 residential rate reform decision (D.15-07-001), the price ratio between the high-tier and low-tier rate is consistent across utilities and is reduced to 125% of each utility's Tier 1 rate. This flattening of tiers increases the price of energy for lower-tier customers and reduces the price for higher-tier customers.

Further changes have been introduced in the successor tariff to NEM introduced in January 2016—"NEM 2.0"—though it will not take effect until on or before July 2017.[35] First, NEM 2.0 requires customer-generators to cover the costs for the services they obtain from the utility. These costs are collected in three ways:

1. Through a required, one-time interconnection fee, which for systems under 1 MW is estimated to be $75–$150
2. Through non-bypass charges that are levied on each kilowatt hour consumed from the grid
3. Through the continuation of a minimum monthly bill of $5–$10

The interconnection fee is a new charge levied on new NEM customer-generators that is equal to the cost incurred by the utility to connect the customer-generator to the distribution network. The non-bypass charges are not new; however, until NEM 2.0, customers only incurred charges on the net kilowatt hours consumed. Now, the customer-generators will incur the non-bypass charges on all kilowatt hours consumed, regardless

33 REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p.93

34 Percentages based on January 2014 California utility rates

35 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

of how much power they return to the grid. The minimum monthly bill is an existing requirement stemming from the CPUC's residential rate reform decision (Decision D.15-07-001)[36] in 2015, and its application to NEM customer-generators is reinforced by NEM 2.0.

The second change in the successor tariff is that it will require customer-generators participating in NEM 2.0 to participate in a TOU program. Under this program, the compensation that customer-generators will receive for the power they provide to the grid will align with the condition of the grid when the power is provided. As the hours of peak solar production generally align with non-peak load hours of the day, under NEM 2.0, many DER customer-generators will receive reduced value for the power they provide to the grid during non-peak load hours.[37] Through the flattening of tiers, the additional fees imposed on NEM 2.0 customer-generators, and the implementation of a TOU program, the economics that have played a key role in driving customer-sited DG in California have weakened. Despite the reduced economic benefits provided under these provisions, the successor tariff does provide a path forward for continued integration of DERs in California.

Other proceedings discussed above include language concerning aligning incentives for utilities to invest in more DERs, which may ultimately result in additional tariff changes.

IN SUMMARY

The two states are taking different approaches, though both are moving beyond NEM to value the benefits provided by DERs. New York has been explicit in its goals to reshape the utility business model, and this is reflected in its Track Two Order. Its approved orders on NWAs to date also provide guidance to utilities on incentives to integrate DERs. California has been less pointed in describing changes to the utility business model; however, the IDER proceeding and the pilot program launched this year are important moves toward changing utility incentives and aligning them with new behaviors.

KEY SIMILARITIES	KEY DIFFERENCES
▪ States are moving to successors to NEM ▪ There is a focus on TOU rates, though California is clearly ahead of New York in implementation ▪ Both are developing incentive structures for NWAs	▪ New York's Track Two has articulated modifications to ratemaking needed to change the utility business model; California has not ▪ Step-down mechanisms from NEM are different (NEM 2.0 in California and Value of DER in New York)

36 http://www.cpuc.ca.gov/General.aspx?id=12154

37 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

ISO Interface

The New York and California Independent System Operators (ISOs) are key to the integration of greater amounts of DERs. Both provide markets within which DERs are valued today.

NEW YORK

The NYISO has programs today that facilitate the participation of select behind-the-meter DERs in the wholesale market. There have been discussions on the appropriate expansion of DER services, and NYISO recently issued a draft roadmap[38] that outlines its approach to integrating DERs into the wholesale market. It proposes that DSPs and ESCOs serve as aggregators of dispatchable DERs that can then be bid into the wholesale market. The NYISO proposal is going through the stakeholder process now.

CALIFORNIA

In California, FERC approved the Distributed Energy Resource Provider (DERP) role in June 2016 (ER16-1085)[39] that allows a third party to aggregate DERs and bid them into the CAISO wholesale market. This rule requires the following:

- Aggregated resources must be at least a half-megawatt in capacity in order to participate in CAISO's wholesale market.
- DERs may be at one pricing node or may span multiple-pricing nodes.
- DERs aggregated across different pricing nodes can be no larger than 20 MW.

Importantly, the California approach enables the aggregation of both dispatchable and non-dispatchable behind-the-meter DERs.

CAISO has since introduced another initiative called Energy Storage and DER (ESDER). ESDER would allow developers to use storage to offset load behind the meter. That storage could then bid demand response services into the wholesale market.

The coordination of the utilities in each state with their respective ISOs will need to continue on several levels. First, all parties need to share forecasted and operational data about the behavior of DERs, and the data must become more granular as these resources proliferate. This information sharing already exists, as it pertains to energy efficiency and demand response programs. Second, the use of the existing wholesale market structures for procurement and sale of DERs as grid resources and services will likely expand. This provides a market mechanism to value and procure DERs even before the implementation of the distribution-level markets currently envisioned in both jurisdictions. Lastly, the ongoing operational coordination between the ISO and utilities to safely and reliably manage the real-time operation of the grid as more DERs appear will be critical.

Conclusion

New York and California are leading the country in DER integration. From a technical perspective, their approaches are similar as they try to resolve barriers to entry for DERs and their developers. Both states are proposing and implementing enhancements to interconnection, hosting capacity, and data sharing. All parties appear to recognize the need for enhanced distribution system planning, and utilities are defining the changes they will make to those processes. They are working to

38 http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/DRAFT%20Distributed%20Energy%20Resources%20Roadmap%20-NYISO%208-17.pdf

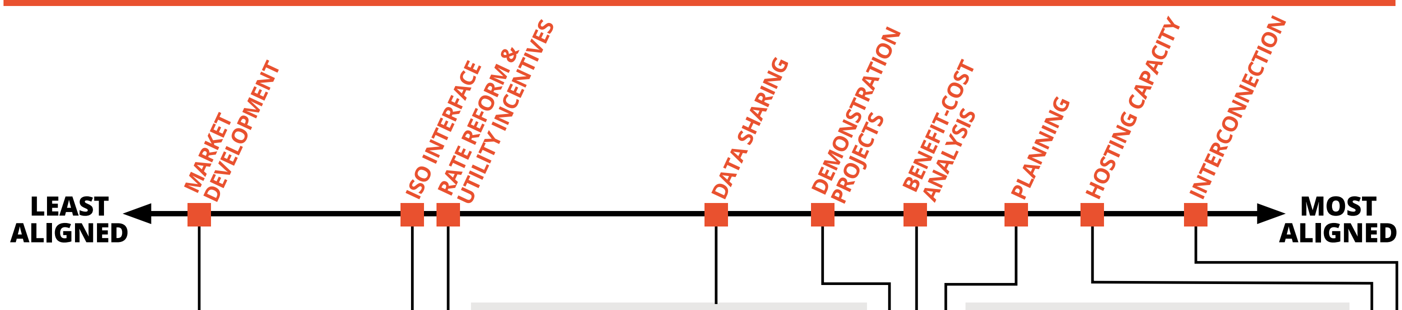
39 https://www.ferc.gov/CalendarFiles/20160602164336-ER16-1085-000.pdf

assess the true value of DERs to the grid and the degree and methods by which they may replace traditional capex. Demonstration projects are filling an important need in piloting technical solutions to what may become grid-wide challenges.

While similar in their approaches to resolve technical questions, the legislative and regulatory approaches differ significantly despite seemingly similar goals. New York is attempting to guide overarching regulatory reform through the Track Two and Value of DER proceedings as the primary drivers. However, many details remain to be implemented through other proceedings and utility rate cases. As mentioned before, there are many interlocking pieces to REV. In California, there is no single overarching proceeding that guides the reforms underway. Instead, those reforms are appearing in myriad proceedings from NEM 2.0, to storage mandates, to the pilot programs being implemented to test incentives related to NWAs. Each approach has merit. New York attempts to "put it all in one place," while California has created a set of building blocks all moving toward reducing GHGs and making a cleaner environment.

The coming years and the experiences of the various entities participating in these two states will determine which process yielded better results. In the interim, the industry can take important lessons and findings from the developments underway in both jurisdictions.

FIGURE 3: CALIFORNIA AND NEW YORK DER INTEGRATION: A CONTINUUM OF APPROACHES



MARKET DEVELOPMENT
NY has an explicit goal of "market animation." CA does not.

ISO INTERFACE
NYISO's DER roadmap focuses on integration of dispatchable resources only. CAISO has implemented the aggregation of dispatchable and non-dispatchable DERs.

RATE REFORM & UTILITY INCENTIVES
NY's Track Two is more focused on Earning Adjustment Mechanisms and Platform Service Revenues than residential rate design. CA has initiated an entire proceeding regarding residential rate design.

DATA SHARING
Both states focused on providing customer and system data. CA is ahead in both.

USE OF DEMONSTRATION PROJECTS
Demos in NY test both business model changes and technical integration of DERs; in CA, the focus is on testing out concepts in Distribution Resources Plans (mainly technical integration).

BENEFIT-COST ANALYSIS
NY has adopted the Societal Cost Test; CA is considering the SCT. CA is focusing on valuing benefits with locational granularity. In NY, the focus will first be on analyzing hosting capacity. CA is doing both concurrently.

PLANNING
Comprehensive plans for the integration of DERs, including hosting capacity and identifying beneficial locations for DER deployment. Both looking at DERs to offset utility Capex. DER penetration rates, particularly solar PV, is a notable difference.

HOSTING CAPACITY
Similar efforts to assess hosting capacity and make it available to DER providers.

INTERCONNECTION
Focus on speeding up the process and automating technical screening.

Source: SEPA & ScottMadden, 2016

Appendix

SUMMARY TABLE OF ACRONYMS

ACRONYM	DESCRIPTION
AMI	Advanced Metering Infrastructure
BCA	Benefit-Cost Analysis
CAISO	California Independent System Operator
CEAC	Clean Energy Advisory Council
CEC	California Energy Commission
CEJP	Clean Energy Jobs Plan
CEMP	Customer Engagement and Marketplace Platform
CEP	Clean Energy Plan
CES	Clean Energy Standard
CPUC	California Public Utilities Commission
C&I	Commercial and Industrial
DER	Distributed Energy Resources
DERP	Distributed Energy Resource Provider
DG	Distributed Generation
DPA	Distribution Planning Areas
DPSS	Department of Public Service Staff

ACRONYM	DESCRIPTION
DRP	Distribution Resources Plan
DSIP	Distributed System Implementation Plan
DSP	Distribution System Platform
EAM	Earning Adjustment Mechanism
ESCO	Energy Service Company
ESDER	Energy Storage and DER
FICS	Avangrid's Flexible Interconnect Capacity Solution
GRC	General Rate Case
IOAP	Interconnection Online Application Portal
IC	Integration Capacity
IDER	Integrated Distributed Energy Resources
IDSR	Integrated Demand-Side Resource
IOU	Investor-Owned Utilities
ISO	Independent System Operator
JU	Joint Utilities
LNBA	Locational Net Benefits Analysis

ACRONYM	DESCRIPTION
NEM	Net Energy Metering
NWA	Non-Wires Alternatives
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PAC	Program Administration Cost
PCT	Participant Cost Test
PSC	Public Service Commission
PSR	Platform Service Revenue
PUC	Public Utility Commission
PV	Photovoltaic power system (solar)
RAM	Renewable Auction Mechanism

ACRONYM	DESCRIPTION
REV	Reforming the Energy Vision
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
SCT	Societal Cost Test
SDSIP	Supplemental Distributed System Implementation Plans
SEP	State Energy Plan
SIR	Standardized Interconnection Requirements
T&D	Transmission and Distribution
TOU	Time of Use [rates]
TRC	Total Resource Cost
UCT	Utility Cost Test

Note: Not captured above are titles of legislation, utility names, specific project names, and units of measurement.

SUMMARY TABLE OF COMMON ELEMENTS OF BENEFIT-COST EVALUATION FRAMEWORKS IN NEW YORK AND CALIFORNIA

NEW YORK'S BCA	CALIFORNIA'S LNBA

Benefits
▪ Bulk
  ▪ Avoided Generation Capacity Costs, including Reserve Margin
  ▪ Avoided Energy
  ▪ Avoided Transmission Capacity
▪ Infrastructure and O&M
  ▪ Avoided Transmission Losses
  ▪ Avoided Ancillary Services
▪ Distribution System
  ▪ Avoiding Distribution Capacity Infrastructure
  ▪ Avoided O&M Costs
  ▪ Avoided Distribution Losses
▪ Reliability/Resiliency
  ▪ Net Avoided Restoration Costs
  ▪ Net Avoided Outage Costs
▪ External
  ▪ Net Avoided Greenhouse Gases
  ▪ Net Avoided Criteria Air Pollutants
  ▪ Avoided Water Impacts
  ▪ Avoided Land Impacts
  ▪ Net Non-Energy Benefits related to utility or grid operations (e.g., avoided service terminations, avoided uncollectible bills, avoided noise and odor impacts, to the extent not already included above)
	▪ Avoided T&D
	  ▪ Sub-Transmission/Substation/Feeder
	  ▪ Distribution Voltage/Power Quality
	  ▪ Distribution Reliability/Resiliency
	  ▪ Transmission
	▪ Avoided Generation Capacity
	  ▪ System and Local Resource Adequacy
	  ▪ Flexible Resource Adequacy
	▪ Avoided Energy
	▪ Avoided GHG
	▪ Avoided RPS
	▪ Avoided Ancillary Services
	▪ Renewable Integration Costs
	▪ Societal Avoided Costs
	▪ Public Safety Costs

Costs ▪ Program Administration Costs ▪ Added Ancillary Service Costs ▪ Incremental T&D and DSP Costs ▪ Participant DER Costs ▪ Net Non-Energy Costs (Not included directly in the methodology but calculated elsewhere for consideration: Wholesale Market Price Impacts in benefits and Lost Utility Revenues and Shareholder Incentives in costs)	**Note:** LNBA addresses locational components. System-level costs potentially addressed in the SCT under consideration.

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