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# Locational Value of Distributed Energy Resources

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# Acronyms and Abbreviations

| | |
|---|---|
| ACR | Annual Consolidation Report |
| AMI | advanced metering infrastructure |
| ARC | Alternative Resource Configuration |
| BCA | Benefit-cost analysis |
| BCAH | BCA Handbook |
| Berkeley Lab | Lawrence Berkeley National Laboratory |
| BPA | Bonneville Power Administration |
| BQDM | Brooklyn Queens Demand Management |
| BTM | behind-the-meter |
| C&I | commercial and industrial |
| CAISO | California Independent System Operator |
| CEE | Center for Energy and the Environment |
| CHP | combined heat and power |
| CMP | Central Maine Power |
| CPUC | California Public Utilities Commission |
| DC PSC | District of Columbia Public Service Commission |
| DDOR | distribution deferral opportunity report |
| DER | distributed energy resources |
| DER-CAM | Distributed Energy Resources-Customer Adoption Model |
| DG | Distributed Generation |
| DIDF | Distribution Investment Deferral Framework |
| DOEE | District of Columbia’s Department of Energy and Environment |
| DR | demand response |
| DRP | distributed resource plan |
| DRV | demand reduction value |
| DSIP | distributed system implementation plan |
| DSM | demand-side management |
| E3 | Energy and Environmental Economics, Inc. |
| EE | energy efficiency |
| EIA | Energy Information Administration |
| EPRI | Electric Power Research Institute |
| EV | electric vehicles |
| FERC | Federal Energy Regulatory Commission |
| GNA | grid needs assessment |
| HECO | Hawaiian Electric Companies |
| I&M | Indiana and Michigan Power |
| ICA | integration capacity analysis |
| ICAP | installed capacity |
| IDSM | integrated demand side management |
| IOU | investor-owned utility |
| IRP | integrated resource plan |
| ISO | independent system operator |
| kV | kilovolt |

| | |
|---|---|
| kW | kilowatt |
| kWh | kilowatt-hour |
| LBMP | location-based marginal price |
| LED | light-emitting diode |
| LIPA | Long Island Power Authority |
| LNBA | locational net benefits analysis |
| LSRV | locational system relief value |
| MCOS | marginal cost of service |
| MEDSIS | Modernizing the Energy Delivery System for Increased Sustainability |
| MI PSC | Michigan Public Service Commission |
| MISO | Midcontinent ISO |
| MN PUC | Minnesota Public Utilities Commission |
| MVA | megavolt-ampere |
| MVAR | mega volt amps reactive |
| MW | megawatt |
| NARUC | National Association of Regulatory Utility Commissioners |
| NEM | net energy metering |
| NERC | North American Electric Reliability Corporation |
| NES | Nashville Electric Service |
| NH PUC | New Hampshire Public Utilities Commission |
| NOC | notice of construction |
| NREL | National Renewable Energy Laboratory |
| NTA | non-transmission alternative |
| NV Energy | Nevada Energy |
| NWA | non-wires alternative |
| NYSERDA | New York State Research and Energy Development |
| NY DPS | New York Department of Public Service |
| NYPA | New York Power Authority |
| NY PSC | New York Public Service Commission |
| O&M | operation and maintenance |
| O&R | Orange and Rockland |
| OSHA | Occupational Safety & Health Administration |
| PCAF | peak capacity allocation factor |
| PECO | Philadelphia Electric Company |
| Pepco | Potomac Electric Power Company |
| PG&E | Pacific Gas and Electric Company |
| PGE | Portland General Electric |
| PSEG | Public Service Enterprise Group |
| PUC | Public Utilities Commission |
| PUCN | Public Utilities Commission of Nevada |
| PV | solar photovoltaic |
| PWRR | present worth of revenue requirements |
| REV | Reforming Energy Vision |
| RFO | request for offer |
| RFP | requests for proposal |
| RGGI | Regional Greenhouse Gas Initiative |

| | |
|---|---|
| RPS | Renewable Portfolio Standard |
| RTO | regional transmission organization |
| SCE | Southern California Edison |
| SDG&E | San Diego Gas & Electric |
| SEIA | Solar Electric Industries Association |
| SEPA | Smart Electric Power Alliance |
| SPP | Southwest Power Pool |
| SW LVAC | Southwest Low Voltage AC Network Group |
| T&D | transmission and distribution |
| TOU | time of use |
| TVA | Tennessee Valley Authority |
| WACC | weighted adjusted cost of capital |
| VDER | value of distributed energy resources |

# Executive Summary

Beginning in the 1990s, a limited number of utilities began assessing the locational value of distributed energy resources (DERs) in distribution or transmission system planning processes. They compared the cost and certainty of load relief associated with deploying a traditional grid solution to alternative DER solutions such as energy efficiency and demand response.

Today, state policies and higher levels of DER adoption are increasingly focused on evaluating DER cost-effectiveness and value. Yet few utilities and states consider their value at specific points on the electric system in planning, procurement, and design of DER programs and rates. That is due in part to barriers such as insufficient information on distribution systems, constraints on DER aggregation, challenges in monetizing all costs and benefits of DERs, and lack of direct experience in using DER solutions to defer or avoid grid investments.

This report focuses on the *locational value* of DERs, which is their value at a specific point on the electric system. *Focusing on distribution systems,* it explores economic valuation, planning, and regulatory considerations for assessing locational value primarily in their role as non-wires alternatives to defer, mitigate, or eliminate the need for some traditional system investments at locations where distribution capacity is insufficient to meet expected future needs. We aim to inform state and local policymakers, public utility commissions, state energy offices, utilities, state utility consumer representatives, and other stakeholders on approaches for assessing locational value. The report includes a sampling of case studies to illustrate how states and utilities are considering the locational value of DERs (Figure ES-1).

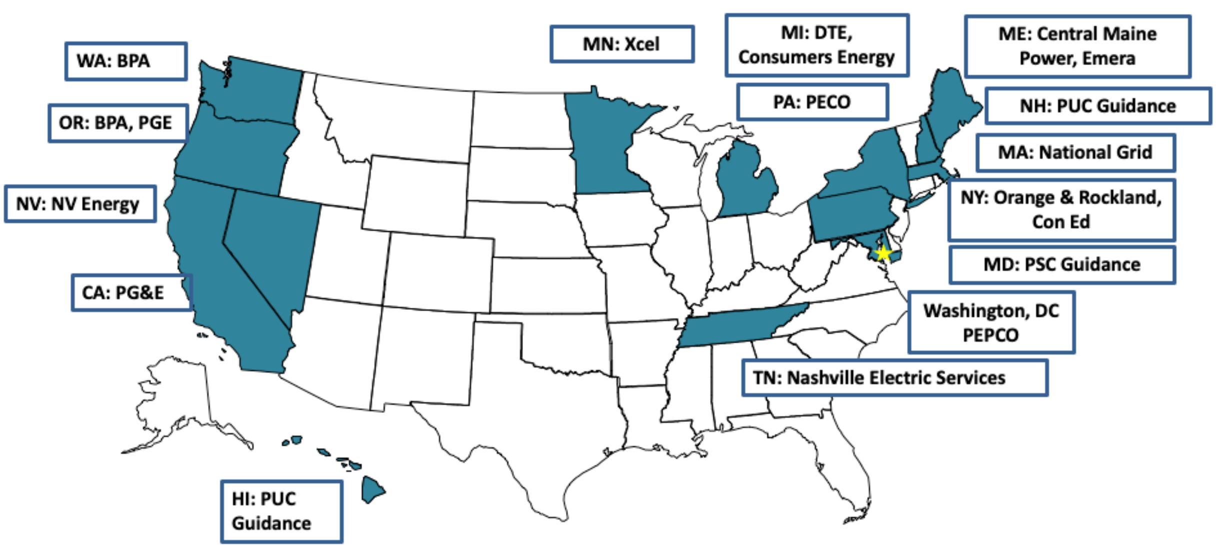



**Figure ES-1. State and Utility Locational Value Case Studies**

DERs can provide significant benefits to the grid by controlling or reducing electricity consumption or generating electricity, thereby avoiding some types of electricity system costs. The potential value of a

DER at a specific location on the grid is determined by the capability of the resource and the potential costs it can avoid in that location. The primary potential location-specific benefit of DERs for the distribution system is their deferral value. That value is tied to specific DER projects, operating at specific times and at specific locations where distribution capacity is insufficient to meet expected future needs. The potential to avoid distribution costs is highly concentrated in locations where loads are growing, components are highly loaded, and there is little or no capacity to accommodate additional growth.

We discuss two methods to assess value of DERs for distribution systems: (1) area-specific avoided distribution costs (also called the *present worth method*) and (2) *marginal cost of service* (MCOS) studies. Using the first method, future utility investment costs are tied to peak load in specific grid locations where there is the opportunity to defer or avoid specific upgrades. These estimates reflect the marginal avoided distribution costs of DERs in specific locations better than the MCOS method does, but they require greater effort and more granular distribution system data. In contrast, system-average MCOS studies are based on historical investments relative to historical growth. These studies indicate the value of avoided distribution capacity. Utilities estimate system-average marginal costs for several purposes, including ratemaking. Both approaches can be integrated into electricity system planning and used at all levels of the electricity system.

DER impacts at the distribution level also may have impacts at other levels of the system. For example, DERs that avoid distribution system losses when and where they are highest also reduce transmission system losses and generation capacity needs, including the planning reserve margin. Those reductions also can reduce air pollution emissions, including greenhouse gases. The estimated value of deferred or avoided distribution capacity, and the magnitude of marginal energy losses that could be avoided by DERs, are the foundation on which DER value to generation and transmission systems is built.

State guidance to utilities varies with respect to the method used to estimate locational value and the approach to procuring DERs to meet distribution system needs. For example, the Minnesota Public Utilities Commission requires utilities to consider the locational value of DERs as part of distribution system planning, but does not specify the approach. Public utility commissions in California, Hawaii, and New York require regulated utilities to solicit requests for proposals (RFPs) for DERs to meet certain types of distribution system needs identified in distribution system planning processes, and these commissions have provided guidance on methods to determine locational value.

Lessons learned from the utility case studies include the following:

- *Identify value.* The highest value opportunities are where low load growth is driving the utility toward a large capital investment, producing significant value per kilowatt of peak load relief. That is because low load growth means fewer utility sales (kilowatt-hours and kilowatts) to cover the cost of the investment. Lower value opportunities occur where DERs are competing with traditional distribution solutions that have greater economies of scale, particularly to serve high growth areas with significant capacity needs.
- *Plan well ahead.* The most successful projects began to evaluate DER alternatives years ahead

of the projected utility system need in order to have sufficient time to deploy DERs and verify that they are providing sufficient and reliable local peak load reductions. The lead time required for some types of major utility distribution system equipment varies.

# 1. Introduction

Distributed energy resources (DERs) offer several potential sources of utility system value. Primary electricity system benefits include deferred or avoided costs for distribution and transmission capacity, avoided distribution and transmission energy losses, deferred or avoided costs of power plant capacity, and avoided hourly and subhourly costs of electricity generation or wholesale electricity purchases. Examples of secondary benefits include avoided ancillary services costs, reduced wholesale market clearing prices, increased reliability and power quality, avoided risks associated with long lead-time investments, reduced environmental cost risk, and improved fuel diversity and energy security (SEE Action 2020a).

Several of these benefits require the value of DERs to be assessed at a specific point on the grid—the locational value. This report focuses on the locational value of DERs for *distribution systems*. According to one definition, "the economic metric for the locational capacity provided by DERs is the future cost of traditional distribution equipment (e.g., substation, transformer, feeder) that would otherwise be needed. The net locational capacity value of DERs is the avoided distribution cost minus the cost of the DER alternative" (Bode, Lemarchand, and Schellenberg 2016). This report also includes discussion and case studies of DER locational value for transmission systems.

**Definition of Distributed Energy Resources**

*A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. In this report, DERs include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).*

Source: National Association of Regulatory Utility Commissioners (2016).

## 1.1 Locational Value Significance and Uses

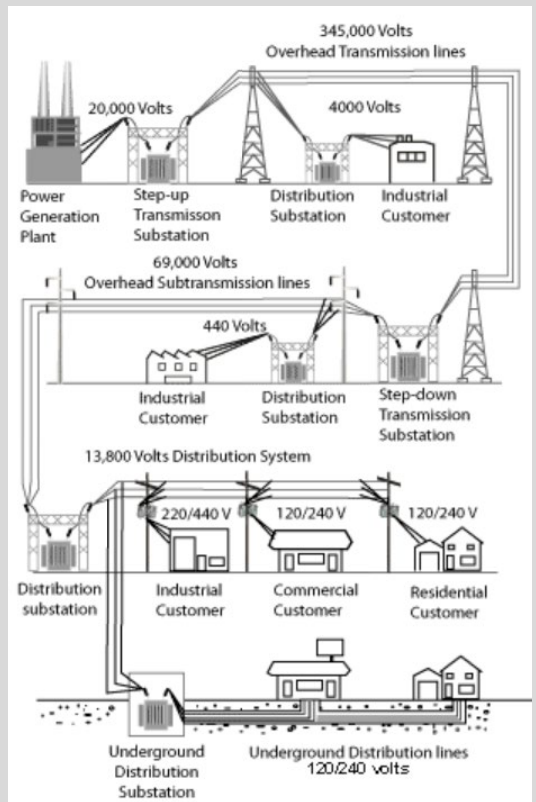
Locational value of DERs is important in large part because utility investments in electricity distribution systems account for the largest portion of capital expenditures for U.S. investor-owned utilities—29% in 2019 ($39 billion), according to Edison Electric Institute.[1] Further, that share is increasing, up from 22% in 2013. The U.S. Energy Information Administration (EIA) estimated that distribution system capital investments for major electric utilities, including investor-owned, municipal, and rural electric cooperatives, nearly doubled over the last two decades (EIA 2018).

[1] See EEI. Industry Capital Expenditures.
https://www.eei.org/issuesandpolicy/Finance%20and%20Tax/EEI_Industry_Capex_Functional_2019.10.16.pdf.

Utility distribution system planners have long developed least-cost plans that minimize lifecycle revenue requirements and meet defined reliability criteria (often N-1 for distribution systems[2]). To ensure that electricity affordability and a reliable, low-cost electricity system are maintained, utilities can consider all value streams associated with electricity resources when making investment decisions. Targeted DERs—energy efficiency, demand response, distributed generation, and storage—are tools for planning and engineering processes that may result in lower cost solutions.

Utilities can conduct *systematic* studies of the locational value of DERs to better understand where to target DERs, reduce load growth for specific areas of the distribution system, and reduce the need for system upgrades. These studies can become a routine and transparent part of the utility's distribution planning process. Information can be used for distribution capacity auctions and DER rate designs.

**Bulk Power System and Distribution System**




The bulk power system includes both power generation and the high-voltage transmission system. Specifically, the bulk power system includes power producing resources that aggregate to a total capacity greater than 75 MVA (megavolt-ampere, gross nameplate rating) and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kilovolts (kV) or above. This does not include facilities used in the local distribution of electric energy (NERC n.d.).

The *transmission system* is comprised of "an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which is transformed for delivery to customers or is delivered to other electric systems" (Markel et al. 2019). The main characteristics that distinguish transmission lines from distribution lines are that transmission lines are high voltage and transmit power over long distances.

*Distribution system* refers to medium-voltage system (typically up to 35 kV) substations, feeders, lines, and other equipment that distribute electricity to and from customers. It begins at a "distribution substation and includes the lines and equipment needed to deliver electric power to [end-use] customers ... at the required voltage" (OSHA).

[2] *N-1* means the system is sufficiently robust to withstand the loss of an element (typically a substation transformer) and continue to serve load reliably.

Utilities also can target DERs to meet narrowly identified requirements through solicitations for non-wires alternatives (NWAs)—also called *non-wires solutions*—to defer, mitigate, or eliminate the need for a subset of traditional distribution (and transmission) investments. To be effective as NWAs, DERs must avoid both the otherwise needed utility distribution investment and the introduction of any other problems based on engineering analysis. Depending on market structure, DERs deployed as NWAs also may be able to provide the utility or centrally organized wholesale electricity market with other grid services—energy, bulk power system capacity, and ancillary services (see Appendix B).

The prospect of future load-growth driven investments in the distribution system due to electric vehicles, coupled with high penetration of other DER technologies in some regions, increases the importance of making well-informed decisions by accurately valuing all potential distribution system solutions, including consideration of the locational value of DERs.

Siting challenges are another driver for consideration of DER locational value. In some cases, siting and acquiring rights of way for traditional grid options, such as a new distribution substation or new transmission line, are difficult. DERs may be a faster and less costly solution, particularly in these instances.

Table 1 describes three primary use cases[3] for employing the locational value of DERs: NWAs procurement, tariff design, and program design.[4] Longer term, locational value can be used to provide locational price signals for DERs using advanced DER control strategies. In terms of timing, NWA procurement occurs when needs are relatively soon—for example, within three years—and clearly defined in terms of magnitude of resources needed by year and hour of day. Tariffs and programs typically target needs that are further in the future, providing a price signal to attract DER projects that may defer, reduce, or avoid grid costs.

**Table 1. Use Cases for Assessing DER Locational Value**

| Use Case | Objective | Capability | Challenges |
|---|---|---|---|
| **NWAs Procurement** | Enable market-based provision of DER services | Procure NWAs to defer transmission and distribution (T&D) investment | Quantification of costs and benefits; risk management |
| **Tariff Design** | Provide price signals for DER locations | Link locational value analysis to tariff design | Efficient, transparent price mechanisms for benefits or costs |
| **Program Design** | Enhance system value of programs | Target program customer acquisition and/or incentives | Customer acquisition; risk management; coordination |

Source: ICF 2018

[3] "Use cases provide a lens through which to understand the value propositions that hosting capacity analysis and locational value assessment provide and to see how these capabilities can help meet utility and stakeholder objectives." ICF 2018.
[4] Distribution markets to enable real-time transactions for grid services is a fourth, and theoretical, use case.

Incorporating the locational value in assessment of DERs began in the late 1980s. Pacific Gas and Electric Company (PG&E), in collaboration with the Electric Power Research Institute (EPRI), evaluated and deployed large amounts of DERs based on the high value of local capacity relief in a few hours of the year in specific locations on the grid. The first project was a 500 kilowatt (kW) solar photovoltaic (PV) installation near the Kerman substation in California's Central Valley, deployed to defer a distribution system upgrade. The second project was in the Delta district in the San Francisco Bay Area, targeting deployment of air conditioner energy efficiency to avoid a subtransmission upgrade.

From the early 1990s through the electric industry restructuring wave in the late 1990s, several electric industry publications described how to decompose the avoided distribution capacity value by location and time for DER evaluation (see Appendix A). In addition, a number of utility case studies tested the ability to target DERs in specific locations and deploy resources based in part on the locational value (see the utility case studies in Chapter 6).

The approaches identified are still used today to assess the locational value of DER in a specific area, primarily the "differential revenue requirement method." This method calculates the difference in a utility's revenue requirement between a distribution project built on its planned schedule versus one that is deferred in time through deployment of DERs. This method also factors in the necessary timing and certainty of load reduction provided by DERs in the constrained location to avoid the investment, as well as a comparison of the cost to utility customers of deploying and operating DERs relative to their deferral value.

## 1.2 Study Approach and Report Structure

This report draws upon the experience and expertise of a team of authors at Lawrence Berkeley National Laboratory (Berkeley Lab), Energy and Environmental Economics, Inc. (E3), and Synapse Energy Economics, Inc. We identified reports for our literature review on the locational value of DERs, including academic publications, utility reports, and regulatory filings and orders. We built on Berkeley Lab's research to identify the value streams and grid services that DERs can offer to the utility system and valuation methodologies and applications (e.g., Frick and Schwartz 2019; Mims, Eckman, and Schwartz 2018; Mims et al. 2017; Mims, Schwartz, and Taylor-Anyikire 2018; SEE Action 2020a and 2020b). Leveraging our distribution system planning research (e.g., Homer et al. 2017; Cooke et al. 2018; Schwartz 2020a and 2020b), we identified practices, metrics, tools, and approaches states and utilities are using to assess the locational value of DERs. We also relied on E3's extensive experience regarding technical requirements for DERs to provide grid services and methods for estimating the locational value of DERs.

The remainder of the report discusses utility system benefits of DERs that provide locational value, technical approaches and tools to estimate DER locational value, factors affecting locational value, and case studies. The case studies provide a range of examples representative of ways that geographically diverse states and utilities have considered the locational value of DERs and how such valuation is considered today. The report concludes by identifying areas for potential future research.

# 2. Utility System Benefits of DERs that Provide Locational Value

DERs can provide significant benefits to the grid by controlling or reducing electricity consumption or generating electricity, avoiding some types of electricity system costs.

DERs can provide grid services to support the generation and delivery of electricity from the utility to the consumer and provide value through avoided electricity system costs (including consumers who provide electricity to the grid)—the cost of acquiring the next least expensive alternative resource that provides comparable services (SEE Action 2020a). Table 2 lists grid services that DERs can provide, grouped into three categories (SEE Action 2020b):

- *Generation*—energy and capacity
- *Ancillary services*[5]—contingency reserves, ramping, and frequency regulation
- *Delivery*—non-wires solutions and voltage support

**Table 2. Examples of Grid Services and Potential Value that DERs Can Provide**

| Grid Service | Potential Value (Avoided Cost) |
|---|---|
| **Generation Services** | |
| **Generation: Energy** | Power plant fuel, operation, maintenance, and startup and shutdown costs |
| **Generation: Capacity** | Capital costs for new generating facilities and associated fixed operation and maintenance costs |
| **Ancillary Services** | |
| **Contingency Reserves** | Power plant fuel, operation & maintenance, and associated opportunity costs |
| **Frequency Regulation** | Power plant fuel, operation & maintenance |
| **Ramping** | Power plant fuel, operation, maintenance, and startup and shutdown costs |
| **Delivery Services** | |
| **Non-wires alternatives** | Capital costs for transmission and distribution equipment upgrades |
| **Voltage Support** | Capital costs for voltage control equipment (e.g., capacitor banks, transformers, smart inverters) |

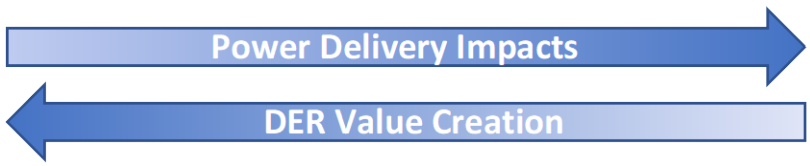
Source: Neukomm et al. 2019

The potential value of a DER at a specific location on the grid is determined by the capability of the resource and the potential costs it can avoid in that location, expressed over a defined period of time. For example, the same type of solar PV plus storage project in two locations may have very different values if, in one location, the resource is able to defer a costly distribution capacity project by providing the necessary energy and capacity locally. In addition, dispatchable DERs—resources that can be turned

[5] "Those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system…." See https://www.ferc.gov/market-oversight/guide/glossary.asp.

on or off, or up or down—have the additional benefit to the utility system of providing operational benefits (SEE Action 2020a).

Figure 1 provides examples of DER value by category in generation, transmission, and distribution systems. Because DERs have location-specific value, value creation begins at the distribution system level. DER impacts also extend to the bulk power system—generation and transmission. For example, by reducing line losses, DERs save energy on the transmission system (as well as on the distribution system) and can reduce congestion. On the generation system, the primary energy value of DERs is through reducing fuel needs for generating power or reducing electricity procurement needs.




| Value Category | Generation (System Values) | Transmission | Distribution (Locational Values) |
|---|---|---|---|
| Energy | Fuel combustion, Power purchase agreement costs | Transmission losses | Distribution losses |
| Capacity | New power plants & storage resources | New transmission facilities | New distribution facilities |
| Operations | Ancillary services | Ancillary services, Volt-var control | Voltage and var control |
| Environment | Air emissions, land use, water, waste | Land and right-of-way procurement | Land and right-of-way procurement |

**Figure 1. DER Value Across the Power Delivery Supply Chain Comes from Avoided Costs**

## 2.1 DERs and System Peak Demand Coincidence

The EIA defines peak demand as "The maximum load during a specified period of time."[6] In practice, utilities and grid operators use a wide range of definitions for peak demand. The time period for measuring peak demand may be a day, month, season, or year. Definitions vary significantly across utilities, states, and regions (Frick et al. 2019).

If load reductions or generation from DERs are aligned with the distribution system peak, they are more valuable to the utility system. For example, if peak loads occur in the mid-afternoon or in summer, in the early evening, distributed PV generation can provide benefits, given the timing of the solar output. If peak loads occur later in the evening, PV may not be able to provide meaningful contributions to meeting peak demand without storage or load flexibility. Additionally, if the transmission and

[6] U.S. Energy Information Administration. Glossary. www.eia.gov/tools/glossary/index.php.

distribution systems peak at the same time, and DER savings or generation are aligned with that peak period, the DER can provide value to both systems.

Figure 2 illustrates how distributed PV with energy storage systems can reduce distribution system peak loads when peaks are coincident. In the figure, a 2,000 kW PV system and 1,500 kW four-hour battery are co-located on the distribution system in the area of need. The battery charges to full capacity from solar in the morning. During a two-hour system peak during the hours ending 15–16, the battery discharges at full capacity and provides 1,500 kW of system peak load reductions. The bulk power system peak overlaps partially with the distribution peak, which occurs during the hours ending 16–19. The combination of PV and storage provides 2,500 kW of distribution peak load reduction.

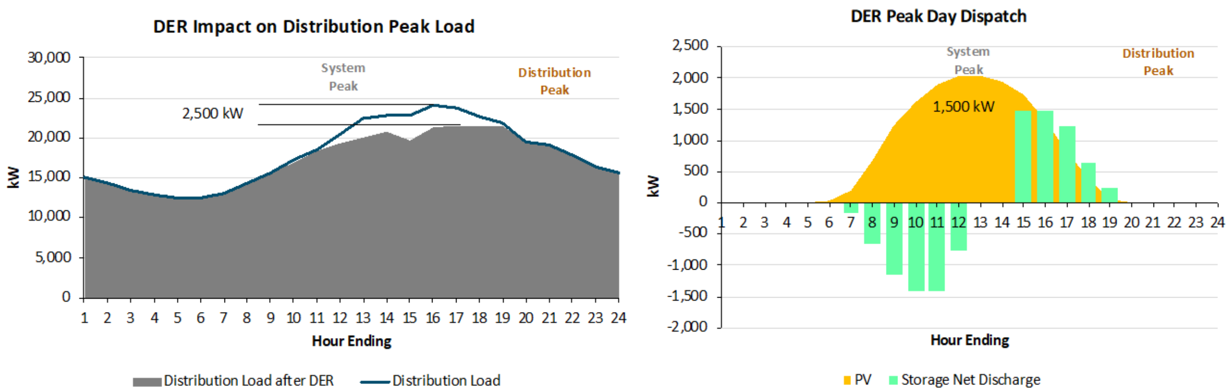



**Figure 2. Peak Load Reductions from PV with Storage when Distribution and Bulk Power System Peaks Are Coincident**

In contrast, Figure 3 illustrates a distribution peak load that occurs later in the evening and does not overlap with the system peak or with significant PV generation. In this example, the first priority for the battery owner is to reduce peak load during peak load hours for the distribution system. (In this illustrative example, the utility's retail rates or programs provide an incentive to do so through time-of-use rates.) With less PV generation that occurs during the distribution system peak, the PV and storage system provide only 1,718 kW of distribution peak load as compared to 2,500 kW in Figure 2, above. After maximizing distribution peak load reductions, the energy remaining in the battery can discharge only 615 kW during the bulk power system peak, as compared to the full discharge capacity of 1,500 kW in Figure 2.

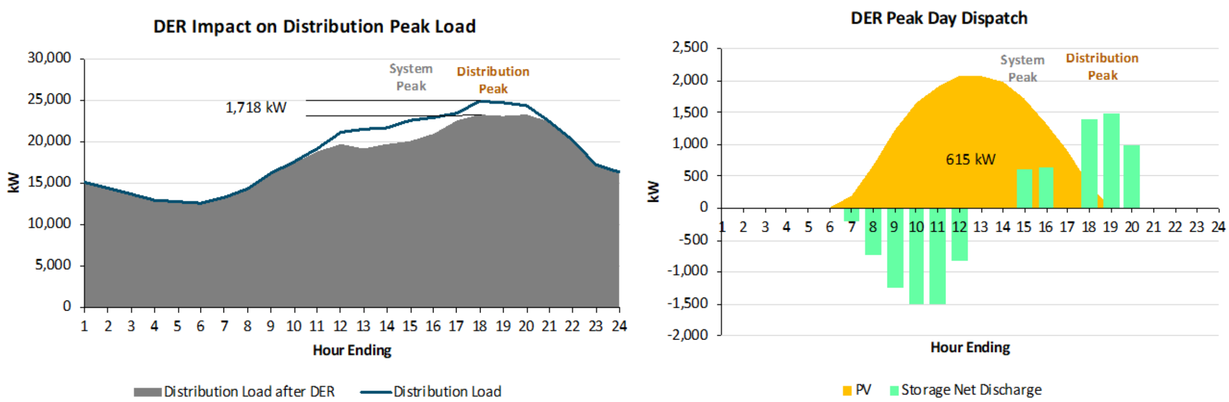



**Figure 3. Reduced PV and Storage Peak Load Reductions when System and Distribution Peaks Are Not Coincident**

Importantly, load growth estimates should be location-specific and reflect growth rates absent incremental DERs (i.e., gross load growth rates). Otherwise, the load forecast assumes resources that have yet to be built. Using such a load forecast in locational value analysis will undervalue the DERs.

## 2.2 Changes in DER Value by Feeder

The vast majority of distribution systems in the United States are configured in a radial, rather than network, format. Figure 4 illustrates the voltage profile along a feeder in a radial distribution system and describes major interactions of DERs with respect to primary engineering considerations. The two significant constraints for feeder designs are voltage and current. Voltage must be kept within a range, while current must be lower than the rating of the equipment available.

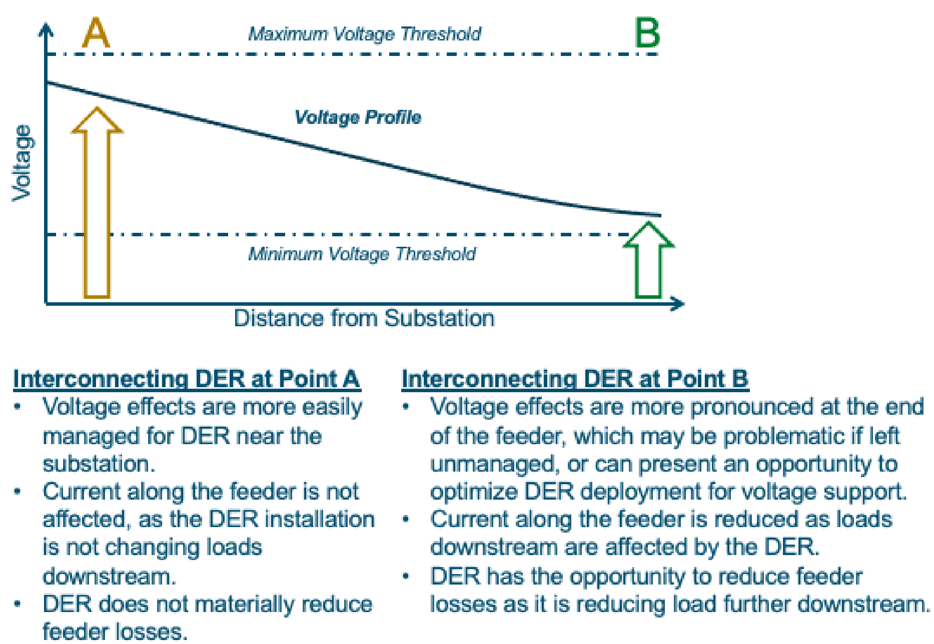



**Figure 4. Voltage Profile on Feeder in a Radial Distribution System**

DERs located near the substation have a smaller impact on voltage because the amount of connected load is high relative to the size of the installed DER. Further along the feeder—at increasing distance from the substation—the same size DER will have a larger impact relative to the connected load at that point in the distribution system and will therefore have a larger impact on voltage. For example, 1 megawatt (MW) of DER installed near the substation, where load might be 10 MW, is a relatively small change to that load. However, the same 1 MW of DER installed further along the feeder, at a point where the load is only 2 MW, would represent a much larger proportion of that load, corresponding with a larger impact on voltage.

With respect to current, DERs installed close to the substation will have little or no effect because downstream loads are not affected, while installations further along the feeder will reduce current. Losses have the opposite relationship with distance from substation. Reducing load at the end of the feeder can reduce losses along the entire length of the feeder, and the impact will therefore be larger than loss reduction associated with a DER installed closer to the substation.

# 3. Approaches and Tools for Economic Analysis of the Locational Value of DERs

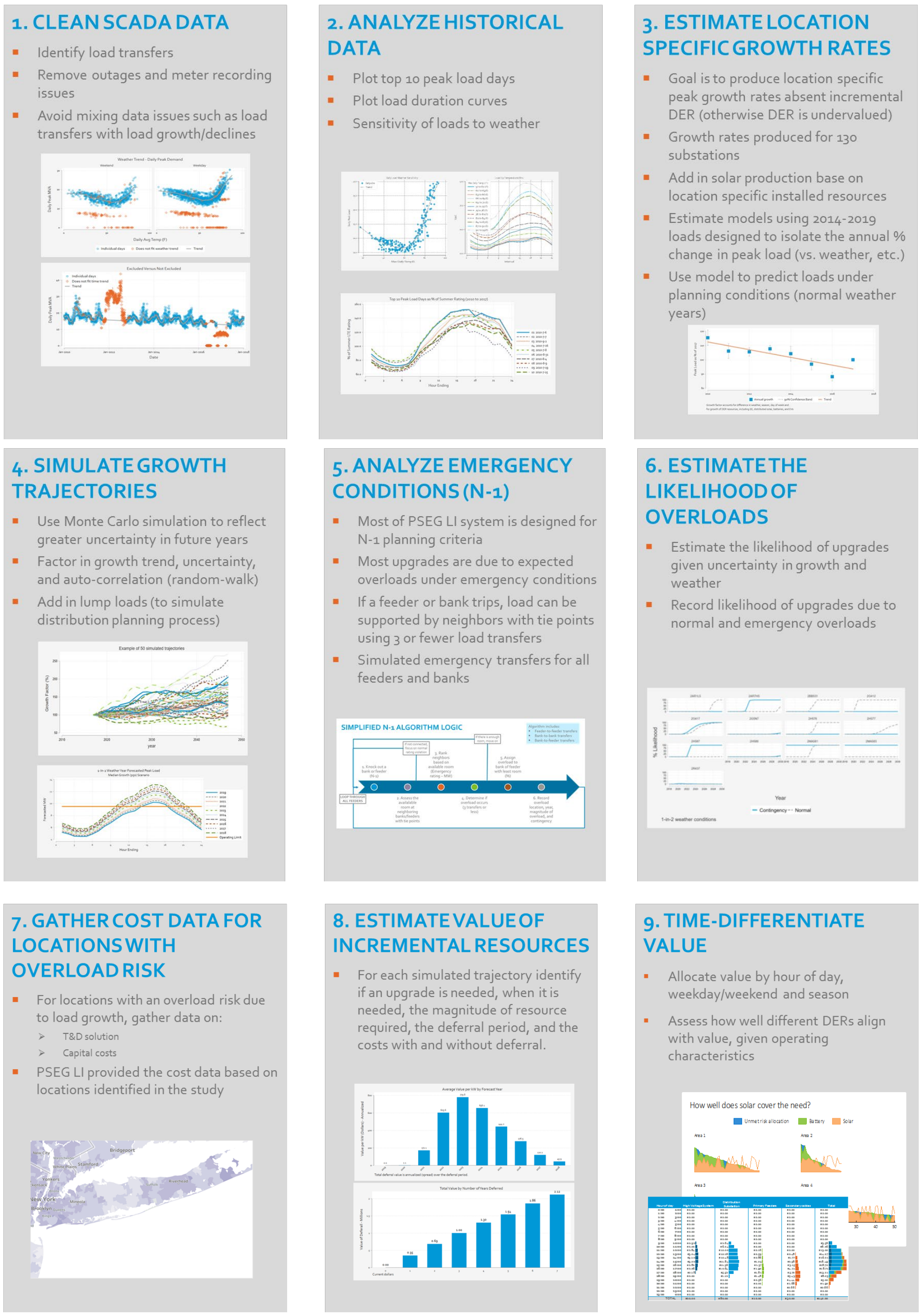



**Figure 5**. **Planning Process for Systematic Locational Value Studies**[7]

[7] Source: Demand Side Analytics. Also see Bode et al. 2015.

Utilities can conduct *systematic* studies of the locational value of DERs (Figure 5, above) to better understand where to target DERs, calibrate incentive levels, reduce load growth for specific areas of the distribution system, and reduce the need for traditional distribution system upgrades or NWA solicitations to meet narrowly identified requirements. New information may need to be gathered for these studies, including hourly load cycles, weather-normalized data, and location-specific growth rates. The information must be in a form that can scale for various levels of analysis, such as at the feeder or substation level. These studies can become a routine and transparent part of the utility's distribution planning process. Information also can be used for distribution capacity auctions (see Consolidated Edison's Brooklyn Queens Demand Management (BQDM) program as an example) and DER rate designs (such as New York's Value of Distributed Energy Resources tariff), discussed in Chapter 5.

## 3.1 Prerequisite Engineering Considerations

Before estimating the locational value of DERs, distribution system planners must first consider if DERs—energy efficiency, demand response, distributed generation, or storage—are an appropriate solution to meet their grid need from an engineering perspective.

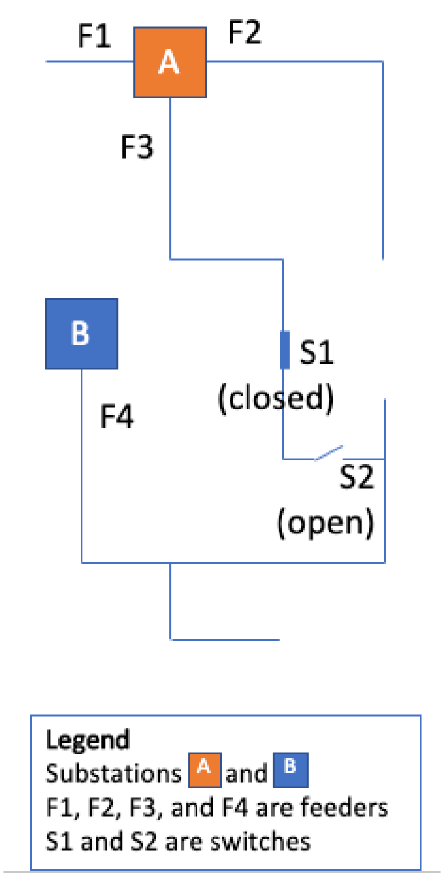



Figure 6 illustrates a distribution planning area comprised of two substations (Substation A and B) with four feeders (F1, F2, F3, and F4) and two switches (S1 and S2). Consider a typical distribution planning problem: the transformer at Substation A is projected to be overloaded in future years and will need upgrades to maintain reliable electricity supply.

First, planners must assess the configuration of the distribution area to assure that the projected overload problem cannot be fixed with reconfiguration—switching the load to a transformer with available capacity. In this example, planners could consider switching load to feeder F4 by opening switch S1 and closing switch S2.

If the load cannot be reconfigured and because Substation B does not have available capacity, the second step is to consider location of the DERs in the planning area. In this example, to help solve the constraint, DERs must be located on a feeder served by Substation A. Therefore, DERs must be located on F1, F2, and F3. Depending on the substation design, there may be more or less ability to balance load across the feeders.

**Figure 6. Example Distribution Planning Area**

If DERs (including energy efficiency) can be located on F1, F2, or F3, the third step is to determine if the DER output profile is naturally coincident with, or could be controlled to be coincident with, the timing of the projected overload. For example, if the overload is projected on hot summer days at midday, then solar generation should be expected to align well with the peak. Figure 7 shows how dispatching DERs, such as solar plus storage or direct load control of water heating and air-conditioning, prevents a reliability problem because the output profile of the DERs is aligned with the grid need by hour of day and forecast year, based on the N-1 emergency rating or another operating limit.

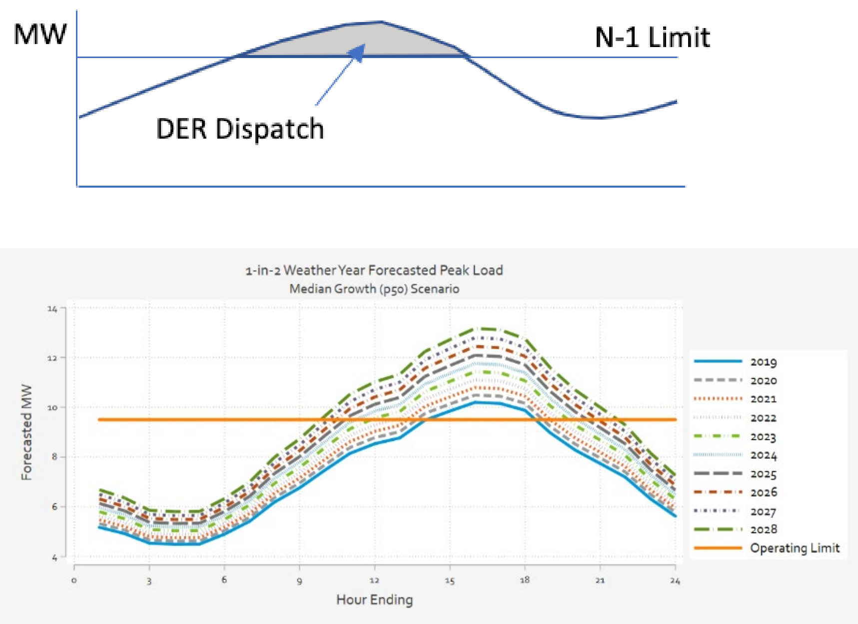



**Figure 7. Timing of DER Output Profile Must Align with Grid Need**

Planners must ensure that the DER solution can avoid the otherwise needed utility distribution investment and that NWAs do not introduce any other problems based on engineering analysis. Typical engineering assessment includes estimating the peak load on the transformer, voltage levels with and without the DER online (in case of DER failure), current levels along the feeder with and without the DER online (in case of DER failure), and protection scheme (fuse and breaker operations) with the DER-based delivery system.

To defer a distribution system upgrade, load reduction must be delivered not only at the right location but at the right time. Engineers use substation load profiles to allocate the value of planned utility investments to specific hours, based on historic peak load hours, thereby creating hourly distribution costs. Figure 8 provides an example of how avoided distribution costs at one location vary over time, across years (top versus bottom panel), hours (y axis), and days (x axis). In this example, the emergency limit is 2,850 megavolt-ampere (MVA). The projected loads in MVA are depicted in boxes to the right of the figure. The red and orange sections of this heat map indicate greater avoided distribution value at this location in 2010 than in 2004, that this value is concentrated primarily in late December, and that midday and evening hours represent the most avoided distribution value. The assessment of avoided distribution value should be revisited regularly to ensure accurate attribution of upgrade deferral value for DERs. Many utilities plan on an annual cycle, presenting a routine opportunity for analyzing this value.

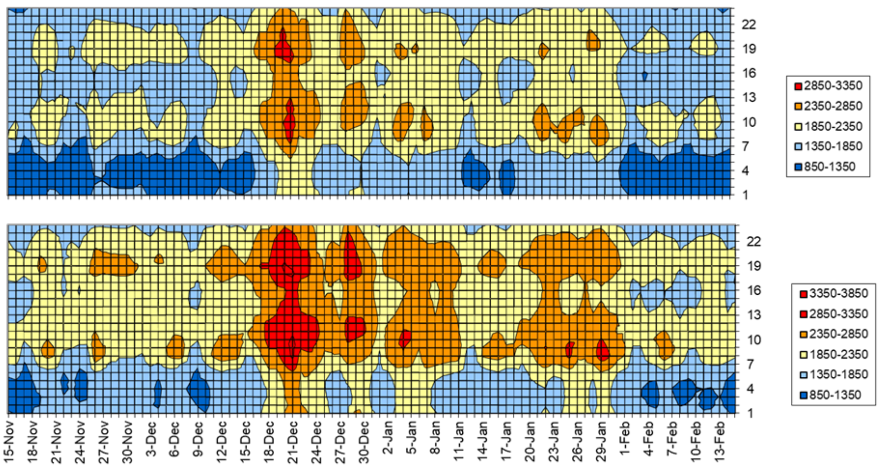



**Figure 8. Varying Value of Local Distribution Costs over Time in California: 2004 (top) and 2010 (bottom)**

As a further illustration of the time-dependency of distribution values, the top graph in Figure 9 depicts the load duration curve for the local area. The curve demonstrates very strong peak loads for a relatively small number of hours, typical for both distribution and transmission systems. The figure shows that targeting DERs with output that can reduce area-specific peak loads when they occur for short periods presents high-value NWA opportunities. The bottom set of graphs is for an illustrative load duration forecast by year, with weather-normalized forecast years.

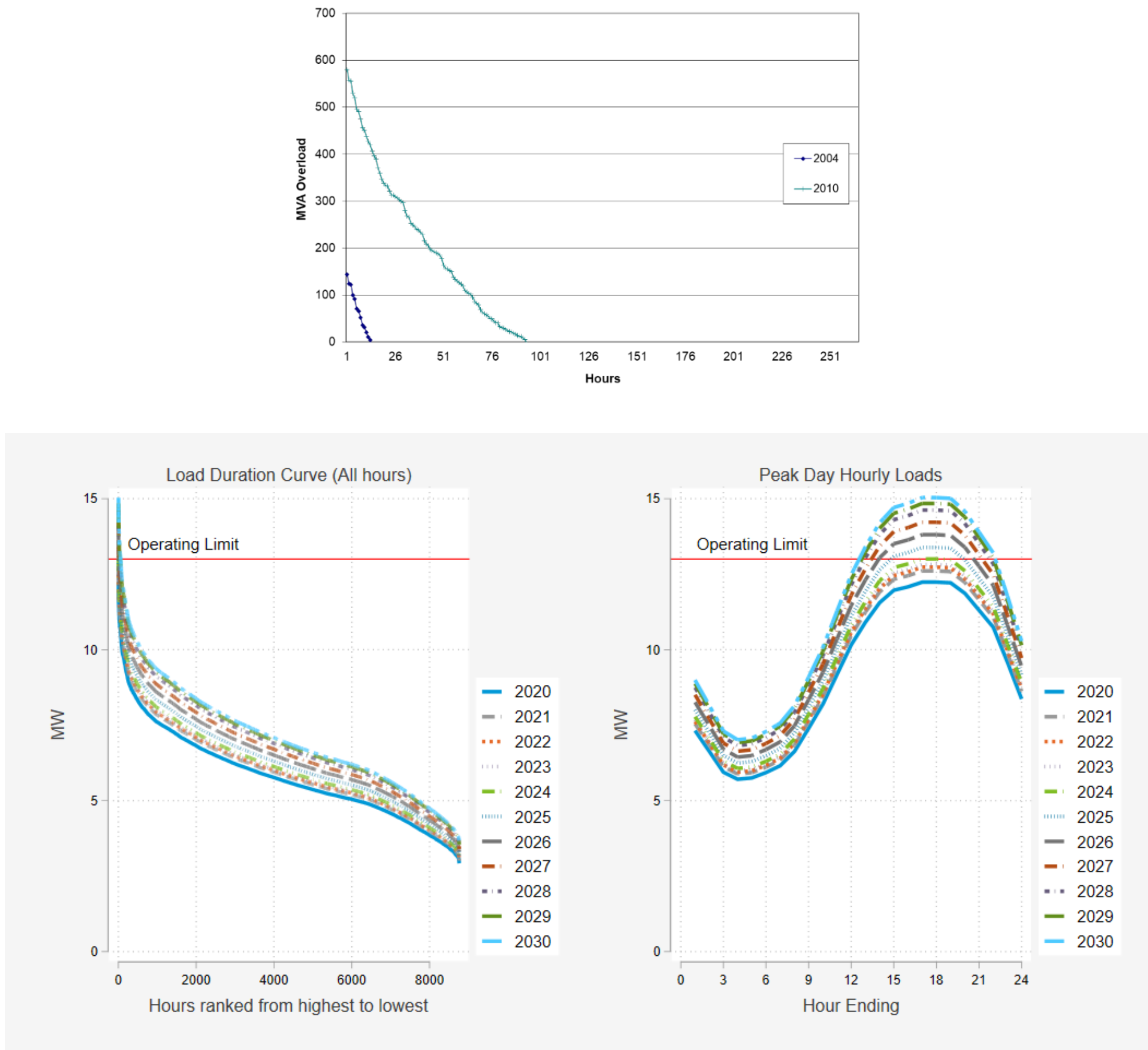



**Figure 9. Example Load Duration Curve for a Local Distribution Area in 2004 and 2010 and for Weather-Normalized Forecast Years (2019–2030)**[8]

Finally, DERs must provide sufficiently reliable load reductions in order to provide enough certainty so that distribution engineers responsible for the local area reliability can confidently defer the traditional investment that would typically address the peak load need. Figure 10 provides an example from a Consolidated Edison study, highlighting results of a combined distributed generation and transmission and distribution system reliability assessment (see Section 6.5 for the full case study). The figure shows that the available capacity to serve the area is greater than the load for three scenarios: (1) no upgrades (magenta dashed line), (2) DER added to the existing system (solid blue line), and (3) the proposed traditional upgrade (dashed green line). The figure shows that at load levels below about 650 MW, the

[8] Forecast graphs from Demand Side Analytics.

probability that the system can serve load is greater than 99.99% in all scenarios. As the peak load grows, DERs can extend the load levels that can be served at about this level of reliability to about 680 MW. The planned upgrade pushes the probability of reliable capacity to serve load above 720 MW.

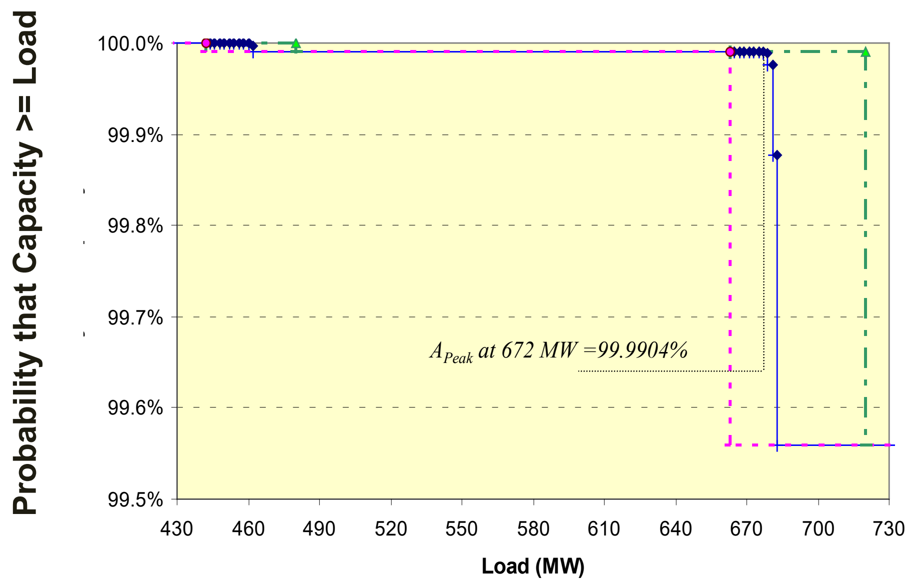



**Figure 10. Availability to Meet Load for the Combined Distributed Generation (DG) and T&D System**

## 3.2 Approaches to Estimating Locational Value

After evaluating if DERs are a potential solution to meet a grid need, two primary approaches are used to estimate the locational value of DERs: (1) area-specific avoided distribution costs calculated using the present worth method, and (2) distribution marginal cost of service (MCOS) studies. Table 3 provides a summary of these approaches, and each is discussed more below.

**Table 3. Two Approaches to Assessing the Locational Value of DERs**

| | How Value Is Assessed | Typical Use Case |
|---|---|---|
| **Area-specific Avoided Distribution Costs** | **Forward-looking value of local capacity deferral** using the present worth method | Evaluation of hourly distribution value of **specific DERs at specific locations** |
| **Distribution Marginal Cost of Service Studies** | Long-run **system average marginal distribution cost** based on the historical relationship between distribution investment and peak load | Evaluation of costs and benefits of **systemwide deployment of DERs** |

While both of these approaches result in a distribution capacity value and have the same units (e.g., $/kW or $/kW-year), they are different and have different applications. Evaluation of area-specific avoided distribution costs using the present worth method results in estimates of marginal avoidable distribution capacity costs based on specific DERs at specific locations. Alternatively, distribution MCOS produce marginal distribution capacity cost estimates that show the general relationship between peak loads and distribution costs, but are not necessarily directly avoidable by DERs. The MCOS results are typically an historical average; the value of a specific DER in a specific place may be higher or lower. Although MCOS does not provide area-specific avoided costs, results from these studies typically are the only information available on distribution value beyond the planning horizon for distribution systems. Distribution system plans provide information on area-specific investments just over the next two, five, or ten years, depending on the utility.

### 3.2.1 Area-specific avoided distribution costs

Economically meaningful estimates of the avoided costs of distribution capacity require a method that captures the area- and time-specific nature of lumpy distribution investments.[9] In the late 1980s and early 1990s, a technique to estimate area-specific and forward-looking marginal distribution costs—the *present worth method*—was developed, and it entered the academic literature and common industry practice. In the present worth method, future investment costs are tied to peak load in specific locations where there are opportunities to defer specific upgrades. These estimates better reflect the marginal avoided distribution costs of DERs than estimates of system marginal cost.

The present worth method determines the value of deferring a local expansion plan for a specific period of time. Using the present worth method, a one-year deferral value equals the difference between the present value of the expansion plan and the present value of the same plan deferred by one year, adjusted for inflation and technological progress. By retaining the expansion plan, the present worth method maintains the effect of investment timing on the marginal cost estimate. Moreover, this method makes no assumptions regarding replacement of equipment. In practice, this means the analyst only uses equipment replacement costs to determine the value of deferring those costs.

The value of deferring capacity in year 1 for $\Delta t$ years is:

$$Present\ Worth\ Deferral\ Value = \sum_{t=1}^{n} \frac{K_t}{(1+r)^t}\left[1 - \left(\frac{1+i}{1+r}\right)^{\Delta t}\right]$$

**where:**

$n$ = finite planning horizon in years,
$t$ = base year the investment or upgrade would be put in service without DERs,
$K_t$ = deferrable portion of distribution investment in year $t$,
$i$ = inflation rate net of technological progress,
$r$ = a utility's cost of capital (discount rate), and
$\Delta t$ = deferral time,[10] which is the peak load reduction divided by annual load growth.

The present worth deferral value can be divided by the associated incremental load change that produced the deferral to obtain a $/kW estimate of the marginal distribution capacity cost:

[9] *Lumpiness* occurs because transformers, for example, do not come in an unlimited number of capacity sizes. A distribution planner typically chooses a 10, 25, 37.5, 100, 167, 250, 333, or 500 kVA single-phase transformer.

[10] The deferral length need not be restricted to integer years. As $\Delta t$ approaches zero, the result of the formula approaches a marginal cost.

$$\$/kW\ Marginal\ Cost = \frac{Present\ Worth\ Deferral\ Value}{Deferral\ kW}$$

The marginal distribution capacity cost estimate varies by *location* because the present worth method is applied to area-specific distribution supply plans. It also varies by *time* because the present worth value in year $t$ is based on the investment stream from year $t$ to year $n$. For example, the present worth value of a given deferral opportunity in year 1 differs from the present worth value in year 2 because the year 1 investment is sunk in year 2, and it is therefore not used in computing the present worth value in year 2. This is most apparent when comparing the present worth value before and after a major capacity investment. Immediately before a major investment takes place, the present worth value is high, mirroring the economic fact that marginal capacity costs should be high when a capacity shortage is imminent. Once the investment is in place, the presence of excess capacity reduces the marginal capacity cost to almost zero, and therefore the following year's present worth deferral value is considerably lower.

Allocation of the marginal distribution capacity cost estimate to specific hours creates the *hourly* marginal distribution capacity costs. This can be useful for a number of purposes, including designing retail rate options, evaluating demand-side management (DSM) programs, determining the operating pattern for dispatch devices, and calculating the cost to serve specific utility customers.

To create hourly marginal distribution capacity costs, the marginal distribution capacity cost estimate is first annualized to form a \$/kW-year estimate, and then allocated across hours of the year using local area load to determine which hours represent the highest distribution capacity needs. This results in hourly marginal distribution capacity cost estimates in \$/kWh. The hourly allocation of the marginal distribution capacity cost estimate introduces additional time variance into marginal distribution capacity costs.

The hourly marginal distribution capacity cost estimate is often determined using the peak capacity allocation factor. Here, marginal distribution capacity costs are allocated to hours in proportion to the likelihood that the hour will contain the peak load. Absent a probabilistic model of ability to serve load,[11] costs can be allocated to hours of the year proportionally based on how high historical load was in any hour for the local planning area.[12] This approach leverages the simple assumption that the distribution of peak loads in the past is indicative of the distribution of likely future peak loads. Peak

[11] Most distribution planning is done based on a forecast of peak load at a planning temperature and not on an assessment of distribution reliability. Linear forecasts assume precise knowledge. Thus, no value is assigned to the years before the linear forecast exceeds the risk tolerance. In reality, no one knows precisely when loads will exceed design ratings or by how much. Probabilistic methods can be used to reflect that infrastructure needs could be triggered earlier or later than expected and that DERs have value in a location that is highly loaded, even if loads are currently flat or declining. This report includes some examples, such as Consolidated Edison, that introduce probabilistic assessment of distribution reliability.

[12] Modeling scenarios and planning judgment also can be used for future projections of loads at various points in the distribution system. For example, scenarios can include increasing levels of distributed solar with, and without, storage.

capacity allocation factors are calculated as the share of incremental load in the peak period divided by the total incremental load in the peak period, as in the following equation:

$$Peak\ Capacity\ Allocation\ Factor_h = \frac{(Load_h - Threshold)}{\sum_{h=1}^{8760}(Load_h - Threshold)}$$

where:
$Threshold$ = the distribution load value below which distribution engineers assume there is no probability that the hour would contain the peak load, given that past loads in that hour (or lower load hours) have never been close to maximum equipment ratings. No distribution capacity value is allocated to loads below the threshold value.

The *threshold value* is typically defined as the load level that is one standard deviation below the historical single-hour peak. The planning criteria followed by each utility dictates the load level used.

**Reliability and the Present Worth Method**

The present worth method makes two assumptions regarding reliability:

(1) If transmission or distribution capacity expansion is deferred by DSM, through energy efficiency and demand flexibility (a subset of DERs), the post-DSM service reliability remains unchanged. This assumption is valid when the kW load reduction from DSM is the same as the kW capacity addition the utility otherwise would build. The assumption may be invalid if the estimated DSM impact is highly uncertain or is overestimated. In that case, the value of DSM can be derated. This deration would be analogous to the reduction in expected generator output due to forced outage rates.
(2) New T&D capacity is added to maintain a predetermined target of service reliability. This assumption could be invalid in the case where an equipment addition would significantly reduce expected customer outages. In this case, the utility could consider reducing the value of deferring investments by the cost to *customers* of higher expected outage-related costs. If the utility is only considering its costs, however, no reduction in deferral value would be needed (other than a small adjustment for some potentially higher maintenance costs).

### 3.2.2 Distribution marginal cost of service studies

The most commonly available source of marginal distribution capacity costs is utility MCOS studies. These studies are used to support a fair allocation of costs between utility customer classes (e.g., residential, small nonresidential, large nonresidential) in rate design in general rate cases. The calculation is based on systemwide analysis of historical (and sometimes planned) investments in distribution capacity and their correlation with peak load.

Practitioners have for many years used ratemaking methods to evaluate the systemwide marginal distribution capacity cost (Parmesano and Bridgman 1992). While these methods are appropriate for systemwide rate-setting and reflect a marginal cost of distribution, they are distinct from area-specific avoided distribution costs. Approaches for distribution MCOS studies reflect a long-run system average marginal cost based on the historical relationship between distribution investment and historical peak load.[13] Since they are based on a regression of investments that already have been made, expenditures underlying these studies are sunk costs and can no longer be avoided. This is significant because MCOS study values do not directly represent costs that can be deferred, and thus are not as helpful for evaluating NWAs as area-specific avoided distribution costs. Additionally, estimated costs in distribution MCOS studies are systemwide averages and are inherently not location-specific. Many areas will have lower distribution value, several will have higher value, and the actual value for utility customers depends on the specific locations where DERs are deployed and how the distribution planning process responds to a resulting change in projected loads for the area.

MCOS studies also are used in value of solar studies in many jurisdictions. Figure 11 illustrates the various value streams included. Several of the categories are broadly accepted categories, such as energy, generation capacity, and T&D capacity, although the estimated values for these categories vary widely. Other value categories are less widely accepted because values are difficult to quantify or there is disagreement (or legal prohibitions in some cases) about whether to include a value, such as for economic development.

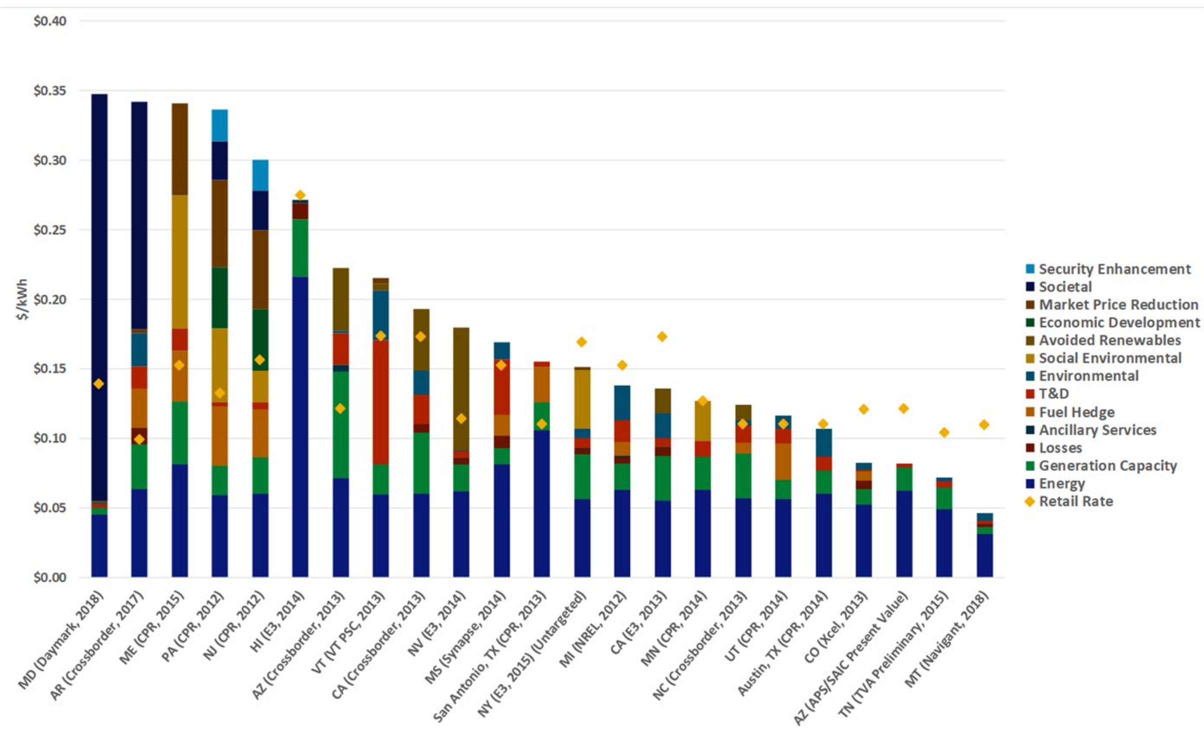



**Figure 11. Value of Solar Estimated Across Various Projects and Jurisdictions**

Examples of current uses of systemwide marginal distribution capacity costs from the MCOS study approach include the “Demand Reduction Value” component of New York’s Value of Distributed Energy Resources tariff, and the distribution capacity component of the California Avoided Cost Calculator used for evaluation of systemwide deployment of DERs. In general, these systemwide marginal distribution

[13] For example, see Knapp et al. 2000.

capacity costs are not intended to reflect the value of a targeted distributed resource. Instead, they are used to attribute a long-run savings level to DERs deployed across the system. New York's tariff also includes a "Location-specific Resource Value," while California's Distribution Resource Planning process for investor-owned utilities is designed to target DER deployment in the highest value areas.

## 3.3 Tools for Calculating the Locational Value of DERs

A variety of tools have been developed to evaluate cost-effectiveness of DER investments by location. Table 4 lists several DER tools that are available today. Some are publicly available on public utility commission and utility websites; some require a subscription to access. These tools vary in their level of analysis scopes (including which DERs can be evaluated using the tool), geographic granularity, and technological focuses. For more information on these tools, including links, see Appendix D.

**Table 4. Tools to Calculate the Locational Value of DERs**

| | Utility/Developer | Publicly Available? |
|---|---|---|
| **Single DER Solutions** | | |
| **Brooklyn-Queens Demand Management Program Cost-Benefit Model** | Consolidated Edison | Y |
| **Avoided Cost Calculator** | E3 | Y |
| **Long Island's Public Service Enterprise Group Value of Distributed Energy Resources Value Stack Calculator** | PSEG | Y |
| **New York Solar Value Stack Calculator** | NYSERDA | Y |
| **Portfolio of DER Solutions** | | |
| **Locational Net Benefit Analysis Tool** | E3 | Y |
| **Integrated Demand Side Management Model** | E3 | N |
| **Solar + Storage Optimization Tool** | E3 | Y |
| **Distributed Energy Resources-Customer Adoption Model (building/microgrid level)** | Berkeley Lab | Y |
| **Integrated Modeling Tool** | Berkeley Lab | Y |
| **REOpt: Renewable Energy Integration & Optimization** | NREL | Y (REOpt Lite only) |
| **Load Relief Needs and T&D Deferral Value Tool** | Demand Side Analytics | N |
| **DER Micro-potential and Non-Wires Optimization Tool** | Demand Side Analytics[14] | N |
| **Battery Storage** | | |
| **bSTORE** | Brattle | N |
| **RESTORE Model** | E3 | N |
| **Storage Value Estimation Tool (StorageVET®)** | EPRI | Y |
| **Electricity Storage Valuation Tool** | Navigant/TenneT | Y |
| **QuESt** | Sandia National Lab | Y |

[14] Many utilities do not produce location-specific growth estimates, and some do not produce weather-normalized loads or annual forecasts. Demand Side Analytics' Granular Load Growth and Forecasting Tool addresses that gap. It uses as inputs multiple years of substation, bank, and/or feeder data; applies data cleaning algorithms to identify load transfer, outages, and data anomalies; estimates location-specific growth rates; weather-normalizes loads; produces 8,760 hourly forecasts; and identifies the timing, risk, and magnitude of overloads for each location.

# 4. Market, Policy, and Regulatory Considerations

Many factors influence assessment of the locational value of DERs. Chapter 2 discussed technical factors, such as the capability of a DER to meet a grid need and the correlation between DER output and peak load for a specific distribution area. Chapter 3 discussed economic factors that serve as the basis for deriving locational value. This chapter discusses market, policy, and regulatory considerations that affect the assessment of locational value of DERs.

## 4.1 Electricity Market Structure

In centrally organized wholesale electricity markets ("restructured markets"), independent system operators (ISOs) and regional transmission organizations (RTOs) facilitate open access to the transmission system and operate markets to determine which resources—including DERs where these resources are permitted to participate—will be dispatched (operated on the system) during each hour of the day.[15] These grid operators rely on competitive bidding to establish the value of grid services (e.g., for day-ahead energy markets). PJM, New York ISO, and ISO New England also operate forward capacity markets to establish prices for capacity services for future years. California ISO, the Electric Reliability Council of Texas, the Midcontinent ISO (MISO), and the Southwest Power Pool (SPP) rely only on energy markets to establish prices for capacity services. Specific market rules differ.

In mixed markets where vertically integrated investor-owned utilities can participate in centrally organized wholesale electricity markets, as well as directly develop or acquire resources, market auctions and utility administrative methods (e.g., integrated resource planning, avoided cost filings) can be used to establish the value of grid services. In regions without organized wholesale markets, resource purchases are available only through bilateral contracts. Vertically integrated utilities in these regions rely primarily, but not exclusively, on administrative methods to determine the value of DERs for providing grid services.[16]

These wholesale market and utility processes were largely designed for supply-side resources and often exclude consideration of DERs for the services they can provide. Often, markets and utilities do not fully recognize the inherent value that well-located and fast-response DERs can provide.[17] For example, FERC-approved tariffs for system capacity may not allow resources compensated under wholesale rates to provide distribution system services to utilities, which would entail compensation under a state-

[15] ISOs and RTOs operate the transmission system independently of, and foster competition for, electricity generation among wholesale market participants. Each of the regional grid operators operate bid-based energy and ancillary services markets to determine economic dispatch. Two-thirds of the nation's electricity load is in ISO or RTO regions.

[16] Traditional wholesale markets (i.e., markets that are not centrally organized) exist primarily in the Southeast, Southwest, and Northwest, where utilities are responsible for system operations and management and, typically, providing power to retail consumers. Utilities in these markets are primarily vertically integrated—they own the generation and T&D systems used to serve electricity consumers. These regions also include federal power marketing agencies, such as Tennessee Valley Authority, Western Area Power Administration, and Bonneville Power Administration.

[17] Fast response resources can provide services that require rapid adjustment to changing grid conditions to maintain stability, such as fast responding frequency regulation (both reg-up and reg-down).

regulator approved tariff (for regulated utilities) or as approved by a municipal utility or rural electric cooperative.[18] Similarly, market or utility requirements may hinder DERs from maximizing their value streams.

### 4.1.1 Dual market participation

To be economically viable, many DERs rely on capturing both locational value—for example, from utility programs—and other value streams such as bulk power system capacity, energy, and ancillary services, which fall within the domain of federally regulated RTOs and ISOs. Dual market participation requires alignment of different markets to capture multiple, or stacked, value streams. In turn, that requires defining how markets will work together to provide as much value as possible from local capacity resources and likely establishing a priority for participation in the case that local and systemwide participation result in conflicting operational needs. Two of the largest barriers to dual market participation are (1) current restrictions on DERs receiving compensation for services and benefits they can provide and (2) costs of aggregation and telemetry to enable monetizing multiple stacked services (Gundlach and Webb 2018; Shenot et al. 2019; FERC 2019; Fisher et al. 2017. This limits the value and therefore the economics and feasibility of financing DERs in today's electricity markets. FERC Order 2222 enables participation of DERs in centrally organized markets through aggregation.[19]

Dual market participation also requires utilities and RTOs/ISOs to understand which grid services can be provided simultaneously and which require a choice by the resource operator. Such grid operator requirements are included in filed tariffs and rules. For energy storage in particular, which has limited energy available, the choice of priority is critical, since a dispatch to provide one grid service may preclude it from being available for another later in the day.

**Valuation versus Compensation**

Chapter 3 discusses two approaches to determining the locational value of DERs to the distribution system. Both approaches rely on avoided distribution system costs. A separate issue is how much DER aggregators or owners should be compensated for the value their resource provides to the electricity grid.

Compensation for the value of DERs is the topic of many publications (e.g., Hledik, Lazar, and Schwartz 2016; NARUC 2016; SEIA 2018; Orrell, Homer, and Tang 2018; Shenot et al. 2019; Darghouth, Barbose, and Satchwell 2019; Satchwell, Cappers, and Barbose 2019) and regulatory proceedings (e.g., Arkansas, Connecticut, Florida, Hawaii, New Hampshire, New York).[20] Chapter 5 includes a description of New York's Value of Distributed Energy Resources approach to compensating DERs for their locational value.

[18] FERC Order 841 (February 2018) requires ISOs and RTOs to revise their tariffs to facilitate the participation of electricity storage resources in wholesale markets. However, compliance filings submitted by market operators under this order highlight that considerations around dual participation in wholesale and retail markets still need to be addressed.

[19] See https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf. The minimum size threshold for the aggregated resources cannot exceed 100 kW. Compliant RTO/ISO tariffs must address several technical considerations, including locational requirements for DER aggregations and metering and telemetry requirements.

[20] Arkansas Docket No. 16-028-U, Connecticut Docket No. 18-08-33, Florida Docket No. 20190176, Hawaii Docket No. 2019-0323, New Hampshire Docket No. DE 16-576, and New York Docket No.15-E-0751.

### 4.1.2 Operation of DERs in nested areas

A related question is the operation of DERs in “nested” areas. An example of a nested area is a DER that is located within a constrained distribution system that also is located within a constrained local transmission zone. To maximize the value of DERs that can be deployed in the nested area and reduce the costs of NWAs, the design of the NWA procurement or utility DER program should encourage DER operations to relieve both constraints when possible. If the timing of the two constraints perfectly overlaps, there should not be an issue in actually achieving the reductions at both locations since a single operation can relieve peak loads on the nested distribution and transmission systems. However, the availability of DERs that meet demand for both distribution and transmission system peaks will be reduced, raising important questions:

- If there is partial coincidence of timing of the constraints, will the DER be available for both peaks, or will it create a shortage for either the distribution or transmission system?
- Should the resource be paid for capacity for both purposes?

If the timing of the peaks does not align, then dispatching the DER to support one constraint may preclude operating the DER for the other constraint, requiring the establishment of dispatch priorities.

Other choices also limit value-stacking. For example, providing ancillary services with a DER requires holding its output at less than maximum level to provide headroom for regulation up services. In addition, battery storage resources must be recharged. Using them to provide reliability services may require maintaining the storage resource nearly full at all times in case of an outage, therefore limiting its operations for other purposes. Bulk power system generation resources face many of these choices. DER owners and aggregators looking to maximize value as they participate in markets for grid services will increasingly face these choices, as well.

It is not possible to capture all of the value in dual markets or nested areas with energy-limited resources such as battery storage (or smart electric vehicle charging and smart thermostats). Still, allowing DERs to participate in markets, coordinating between utility DER programs and ISO/RTO markets, and establishing priority for cases of conflicting signals can improve the value proposition.

## 4.2 State Energy Policies and Regulatory Context

State energy policy related to electricity resources plays a role in determining the value of DERs. For example, utility regulators in California[21] and New York[22] have recognized DER benefits, including the distribution locational value and reduction in specific transmission and distribution costs. Figure 12 depicts DER value streams identified in different jurisdictions. Some of these value streams are locational (e.g., avoided distribution investments), while others are not (e.g., avoided renewable energy procurement). The inclusion and calculation of value components varies across jurisdictions based on state policies, utility definitions, regulatory compliance mandates, and existing markets (Woolf et al. 2017; Woolf et al. 2020).

[21] Pacific Gas and Electric Company. *Demonstration Projects A and B Final Reports*. December 27, 2016.

[22] Consolidated Edison. *Distributed System Implementation Plan.* June 30, 2016.

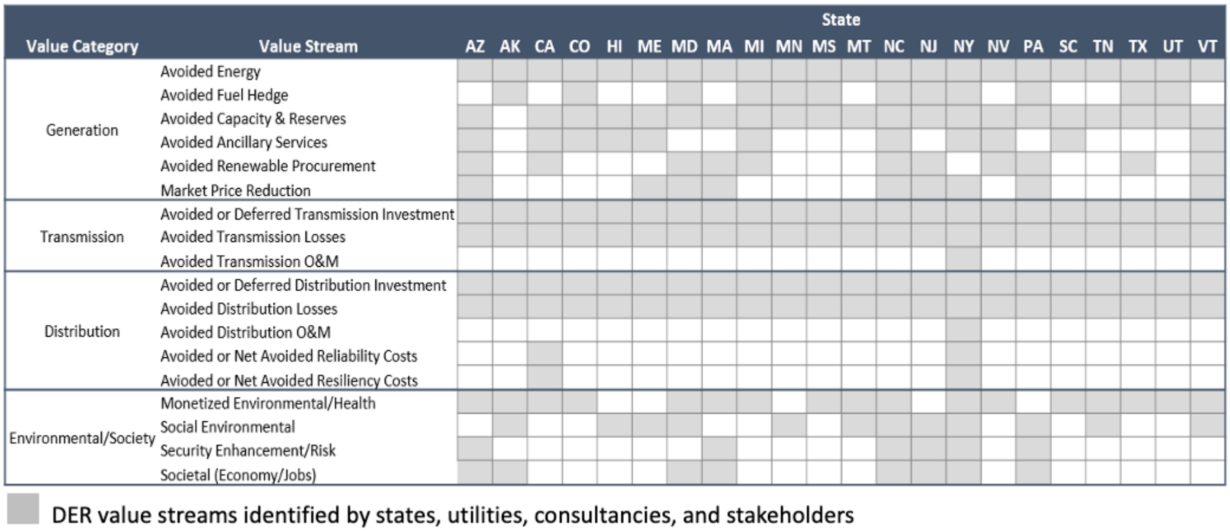



**Figure 12. Value Streams for DERs by Jurisdiction**

Source: Adapted by E3 from Shenot et al. 2019 and DOE 2018.

Additional benefits—and thus value—may be included in valuation analysis, depending on the perspectives considered. The *participant* perspective includes costs and benefits that accrue to consumers who implement DERs. In addition to utility system costs, participant costs may include the customer portion of the installed DER cost and financing costs, transaction costs, increased operation and maintenance costs, other fuel consumption (e.g., natural gas, oil, propane), and water consumption. Benefits may include reduced electricity bills and operation and maintenance costs; increased productivity, comfort, health and safety, and aesthetics; resilience to outages; and reduction in other fuel use and water consumption. For low-income customers, benefits of particular importance are reduced energy burden, medical costs, and home foreclosures, as well as avoiding the need to move due to unpaid utility bills (Woolf et al. 2017).

The *societal* perspective includes consideration of costs and benefits that accrue to society as a whole. In addition to utility system costs, societal costs may include the participant costs listed above. Benefits may include participant benefits and reduced water consumption and wastewater costs from efficiency technologies; reduced water consumption from electricity generation from power plants; reduced air pollutant emissions (if not included in utility system benefits); reduced liquid and solid waste from electricity generation; reduced water consumption for cooling electric generation units and natural gas extraction; reduced land impacts from new generation facilities; reduced land, air, and water impacts from mining or extraction; increased energy security from reduced reliance on imported fuels; increased economic development and job creation relative to supply-side resources; and improved public health impacts including indoor and outdoor air quality. Benefits of particular importance to low-income customers include alleviating poverty, improving community strength and resiliency, and reducing home foreclosures.[23]

[23] Community engagement can help identify costs and benefits that may disproportionately affect some communities.

In addition to specifying benefits that will be considered, state policies and regulations can reduce or restrict DER value and compensation. Many DERs must be aggregated to provide a substantive resource for utilities and markets. Often, third-party aggregators are needed to facilitate DER participation. Some state laws or regulations impede third-party aggregation services for utility customers. In addition, traditional cost-of-service regulation inherently provides a financial incentive for utilities to prefer capital investments for which they earn a rate of return over customer- or third party-owned DERs that could defer or avoid capital investments and provide net benefits to utility ratepayers (Lazar et al. 2016).

### 4.2.1 Advanced distribution system planning and equipment

Several states require consideration of the locational value of DERs as NWAs, often as part of distribution system planning. However, the sophistication and resolution of distribution planning and operations varies widely by utility, and there may be limited visibility of distribution system operations. Lack of sufficient distribution system data impedes efforts to identify potential customers for DER deployment and to site DERs for maximum utility system benefit.

Advanced metering infrastructure (AMI),[24] which improves utility data collection capabilities and allows for bidirectional communication with customers, may help overcome this challenge by providing data to maintain and improve the operation of the distribution system (E9 Insight and Plugged in Strategies 2020). Installation of AMI has been increasing across the country, although not uniformly.[25] As of 2019 about 60% of all meters in the United States were advanced (EIA 2020a).

Another way to increase visibility into the distribution system is through distributed energy resource management systems, which can form part of an advanced distribution management system. Both of these systems improve situational awareness. However, such systems are nascent, and systemwide rollout may take several years.

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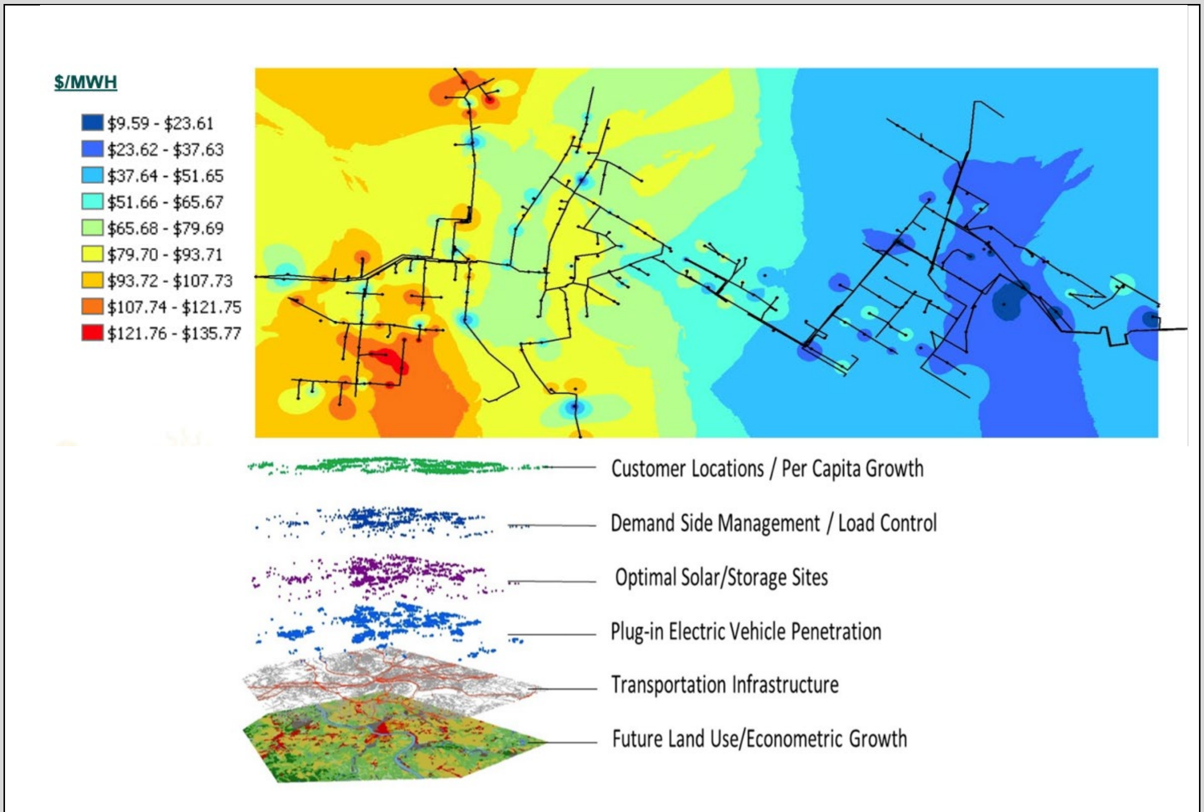
[24] *AMI* is defined by the U.S. Energy Information Agency as "Meters that measure and record usage data at a minimum, in hourly intervals and provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data." See Form 861 Instructions for Schedule 6, Part D. https://www.eia.gov/survey/form/eia_861/instructions.pdf.

[25] FERC 2019. Also see Cooper and Shuster 2019.

**Access to More Granular Data and Geographical Information System (GIS) Overlays**

Utilities are able to access more granular data with AMI and other advanced distribution system technologies. For example, utilities can overlay their distribution system topology with individual distribution circuit or utility customer data. Public utility commissions in California and New York require regulated utilities to make maps of distribution system topology and available hosting capacity available to DER providers.[26] This transparency lets potential providers of peak load solutions identify where they can provide value and also where connecting some types of DERs to the grid (e.g., solar PV) is particularly costly or difficult.

The figure below shows an analysis of load growth for Southern California Edison, highlighting in red circuits that have very high marginal avoided cost, highlighting the most cost-effective locations for DERs. Source: Martinez et al. 2020. Load growth is projected using multiple GIS layers incorporating land use, transportation, customer demographics, and DER adoption.




[26] New York Hosting Capacity Maps: https://www3.dps.ny.gov/W/PSCWeb.nsf/All/6143542BD0775DEC85257FF10056479C?OpenDocument; SCE DRP External Portal: https://ltmdrpep.sce.com/drpep/.

Distribution system planning requirements may also hinder the use of DERs. Distribution system protection and coordination rules are intended to ensure safe operation of the distribution system and minimize power disruptions, primarily by disconnecting local areas experiencing an electrical fault. These rules may be at odds with the use of DERs to provide distribution system benefits, as the rules have historically been designed largely for unidirectional power flows. For example, rules may require solar PV to trip offline when tolerance limits are exceeded, exactly the time when injecting power into the local system could be helpful from systems that can continue to operate safely.

Similarly, DER projects may not be as straightforward to evaluate using conventional planning criteria as traditional capacity investments are. For example, it is difficult to assess DERs' contribution to reliability requirements when using N-1 contingency planning, which focuses on the reliability provided by individual, larger assets. This framework is not directly transferrable to assessment of modular DER alternatives. Also, the diversity and relative nascency of different types of DER technologies, products, applications, and use cases may complicate understanding and confidence among potential customers, utilities, and grid operators.

Public utility commissions and state policymakers have taken a variety of actions to overcome these and other barriers:

- Assessing the locational value of DERs and NWAs through pilots, including understanding the value proposition, testing procurement and program designs, and acquiring performance data
- Developing retail rate structures aligned with the time and locational value of DERs, including time-varying rates or incentive payments for distribution areas with identified constraints
- Decoupling utility retail sales from profits, as well as providing metrics, targets, and positive financial incentives for utilities to consider and implement cost-effective NWAs
- Identifying enhanced methods and practices for valuing DERs in planning on a par with traditional options for meeting distribution system and bulk power system needs (SEE Action 2020a)
- Addressing barriers to third-party aggregation of DERs to enable participation in utility procurements and programs and centrally organized wholesale electricity markets
- Adopting the new IEEE 1547 standard, which allows solar PV to ride-through certain distribution system disturbances
- Requiring utilities to assess and make publicly available hosting capacity analysis (see text box below)

### Hosting Capacity Analysis

*Hosting capacity* is the amount of DERs (e.g., solar PV) that can be interconnected to the distribution system without adversely impacting power quality or reliability under existing control and protection systems and without infrastructure upgrades. Hosting capacity analysis considers several power system criteria, including voltage violations, thermal overloads, power quality, and reliability and safety. Hosting capacity analysis has important location-related implications for DERs, but does not itself assess the locational economic value of DERs.

Primary methodologies include stochastic analysis using iterative power flow simulations (such as different DER project sizes in different locations) at each node until violations occur to provide a range of uncertainty. Streamlined approaches use algorithms for each power system limitation to estimate when violations occur. EPRI’s DRIVE tool is a hybrid of the streamlined and stochastic methods.

The most common use case today for hosting capacity analysis is to guide DER development by providing “heat maps” that indicate harder or easier locations on the distribution system for installing solar PV. The figure below shows a heat map for the Denver area, indicating areas where only limited (orange) or no (red) solar PV can be installed without infrastructure upgrades. Utilities also may provide spreadsheets showing daytime minimum loads, a fundamental limit on distribution system hosting capacity. Thus, hosting capacity analysis can help enable DER development by providing information on locations where interconnection costs may be lower.

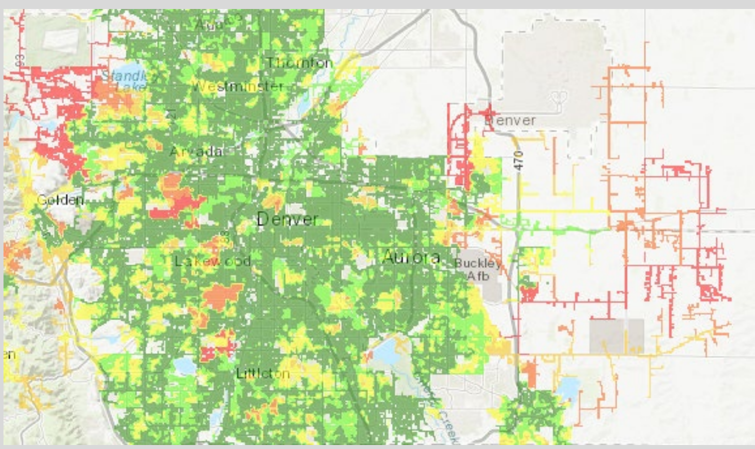



Figure source: https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map

Another use case is to streamline interconnection technical screening. Results from hosting capacity analysis can replace existing rules of thumb for determining whether the proposed DER interconnection requires detailed technical studies. Hosting capacity also can inform distribution system planning, including how much DER the system can accommodate in future years and locations where proactive utility upgrades can be considered (ICF 2018). In the future, hosting capacity analysis may be performed in real time to inform system operations.

The frequency of updating the analysis, and the types of data and granularity provided, affect the usefulness of the information for project developers and utility customers. In addition, most utilities to date do not include DERs beyond solar, such as EVs.

# 5. State Guidance on the Locational Value of DERs

Several jurisdictions have provided legislative or regulatory guidance, or both, related to the locational value of DERs. This chapter describes jurisdictions that have provided guidance to date on using locational value in tariff design, program design, and compensation for DERs. The next chapter provides utility case studies in these and other states (Figure 13).

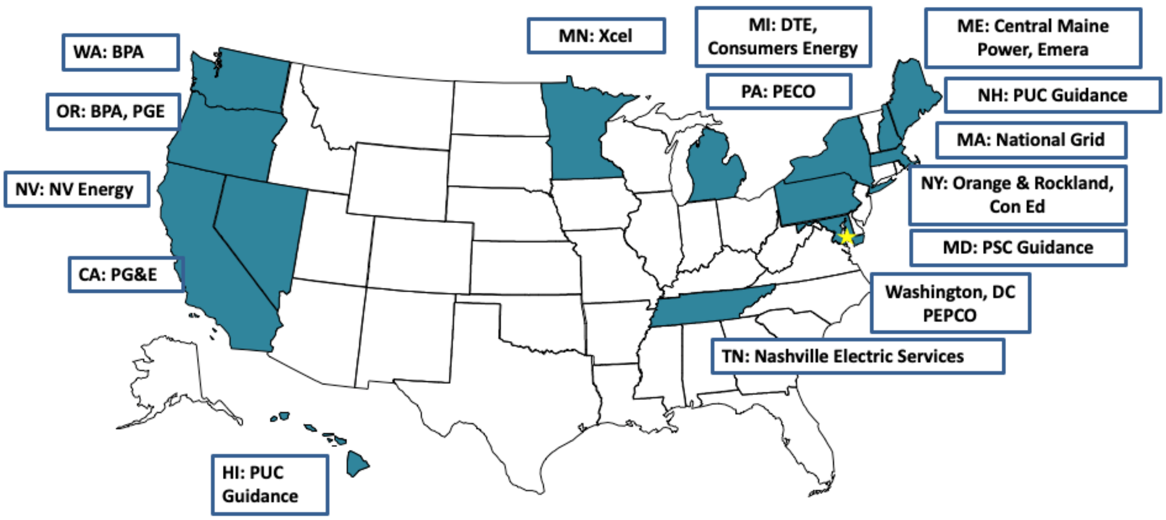



**Figure 13. States and Utilities Represented in This Study**

Jurisdictions provide varying levels of guidance with regard to the method regulated utilities use to estimate the locational value of DERs and whether and how to procure DERs to meet T&D system needs. For example, California, Nevada, and New York have specified criteria, and in some cases methods, for such analysis for distribution system planning. These and other states have prescribed or approved utility criteria for NWA analysis, which values DERs in the context of a particular grid need (e.g., load relief or reliability) at a specific location (point on the distribution or transmission system). Some states, such as California, Hawaii, and New York, require regulated utilities to issue requests for proposals (RFPs) or request for offers (RFOs) to reveal the locational value of DERs. Table 5 summarizes approaches to estimate the locational value of DERs in distribution system planning (and in some states in other applications) and requirements (if any) to procure DERs for regulated utilities.

**Table 5. Approaches to Estimate the Locational Value of DERs for Regulated Utilities**

| | |
|---|---|
| **California** | Use Avoided Cost Calculator and LNBA tool in distribution system planning (see Appendix D). |
| **District of Columbia** | Ad hoc location-specific BCA; Pepco is expected to propose a "locational marginal value" approach. |
| **Hawaii** | Utility issues solicitations for grid services from customer-sited DERs. Solutions are evaluated through RFPs. |
| **Maine** | Office of Public Advocate coordinates NWA analysis using utility cost test and avoided costs that are consistent with those used by the Efficiency Maine Trust. |
| **Massachusetts** | Calculations may occur in grid modernization plans but are not required. |
| **Michigan** | Public Service Commission staff recommended that the Commission define locational value in a future order. |
| **Minnesota** | For distribution upgrade projects >$2 million, analyze how NWAs compare with traditional grid solutions at specific locations in terms of viability, price, and long-term value. |
| **Nevada** | Use locational net benefit analysis in distribution system planning. |
| **New York** | Use Consolidated Edison, LIPA, and NYSERDA tools (see Appendix D). |

*LNBA - locational net benefit analysis; BCA - benefit-cost analysis*

In addition, several states have provided guidance to utilities on hosting capacity analysis. While such analysis does not assess economic value of DERs, it has important location-related implications.

**Example State Requirements for Hosting Capacity Analysis**

**California:** The three large investor-owned utilities must use an iterative process for "integration capacity analysis" using the 576 hours of the year that represent the actual 24-hour load profile of the peak and minimum load day for each month of the year. The goal is to streamline the technical interconnection process. Analysis includes multiple types of DERs. Maps are updated regularly. Refinements to data validation and online map functionality are currently under consideration.

**Hawaii:** The utilities update "Locational Value Maps" online in real time to provide an approximate indication of available interconnection capacity for solar installations. Maps show the percentage of space currently available on the higher voltage primary system but not on secondary neighborhood circuits embedded within the primary system. Maps also show total output capacity available in the area, plus distributed generation currently on each circuit compared to peak demand on each circuit.

**Minnesota:** State law (Minn. Stat. 216B.2425, Subd. 8, 2015) requires utilities operating under multiyear rate plans (Xcel Energy) to conduct a distribution study to identify interconnection points for small-scale distributed generation, as well as system upgrades to support its development. The Public Utilities Commission defined this threshold as distributed generation resources 1 MW or smaller (Docket No. E002/M-15-962, June 28, 2016, Order). Among the Commission's requirements:

- Reliable estimates and maps of available hosting capacity at the feeder level
- Details to inform distribution planning and upgrades for efficient distributed generation integration
- Detailed information on data, modeling assumptions, and methodologies

Xcel Energy uses the EPRI Drive tool. Smaller utilities perform spreadsheet analysis by feeder and post daytime minimum load data. The Commission's most recent order in part adopts a long-term goal for Xcel Energy to use hosting capacity analysis in fast-track screens for the interconnection process. For the next analysis, submitted November 1, 2020, the Commission required Xcel Energy to provide cost estimates for more frequent updates and include an evaluation of costs and benefits for more advanced use cases: (1) replacing or augmenting initial review screens and supplemental review in the interconnection process and (2) automating interconnection studies. The Commission also required Xcel Energy to include as part of this filing a discussion of information and resources required for a *load* hosting analysis and how such analysis could help achieve state energy policy goals related to beneficial electrification.

**New York:** Hosting capacity maps are required for all circuits ≥12 kV. Utilities post maps to a central website. The primary use case is to guide DER development to areas with lower expected interconnection costs. The utilities use EPRI's Drive tool.

**Nevada:** The PUC requires hosting capacity analysis using a load flow analysis and forecasted distribution facilities at the substation, feeder, and primary node levels. Scenario analyses must be performed under normal conditions and planned and unplanned contingency conditions. "Real-time" hosting capacity data must be publicly available. NV Energy used the Synergi tool for the analysis, included as part of its first Distributed Resource Plan.

## 5.1 California

California is a pioneer in quantifying the locational valuation of DERs. Utilities in the state began to consider the locational value of DERs through local integrated resource plans in the late 1980s, which resulted in the first DER projects installed as alternatives to traditional capacity investments (see, for example, the PG&E Kerman and Delta case studies in Chapter 6). These plans evaluated specific projects—often high profile or those with public opposition— to determine if a portfolio of DERs could cost-effectively defer or avoid the planned distribution system upgrades.

Table 6 summarizes four key areas where the state's regulated utilities are required to integrate the locational value of DERs in California today: (1) DER program cost-effectiveness testing that incorporates a value of T&D capacity, (2) local area (distribution) planning for NWAs to reduce utility capital expenditures, (3) rate-setting with a dynamic distribution customer charge or dynamic DER compensation rate, and (4) hosting capacity analysis that provides information on how much DER can be interconnected to various parts of the system.

**Table 6. Regulatory Framework for Location-Specific DER Valuation in California**

| | |
|---|---|
| **Program Cost-Effectiveness** | The California Public Utilities Commission (CPUC) publishes the Avoided Cost Calculator annually. It includes the climate zone-specific value of distribution capacity based on utility marginal cost of service studies. |
| **Locational Net Benefits Analysis** | The Distribution Resource Planning (DRP) process results in non-wire RFOs for distribution capacity in place of specific capital upgrades. The value of deferral is based on the present worth method in the Locational Net-Benefits Analysis Tool. |
| **Rates and Tariffs** | San Diego Gas & Electric implemented two retail rates for smart EV charging that included a dynamic distribution value (Vehicle Grid Integration Rate, Grid Integration Rate). Utilities also have deployed some demand response resources to support local distribution needs. |
| **Hosting Capacity Analyses** | The CPUC requires DRPs to include an Integration Capacity Analysis (ICA). The IOUs submitted ICA reports in 2016 that summarize demonstration project results, lessons learned, and utility recommendations on the methodology. An ICA working group proposed refinements and improvements that are under consideration at the CPUC. The utilities were required to post available hosting capacity in publicly accessible online maps in December 2018. |

### Program Cost-Effectiveness

In 2004, the CPUC introduced area- and time-specific avoided costs to evaluate the costs and benefits of energy efficiency by climate zone. Among other categories, avoided costs include a T&D capacity value for load growth-related costs that DERs can avoid. Each of the large regulated electric utilities calculates marginal T&D avoided costs for general rate case filings. Southern California Edison (SCE) and SDG&E calculate systemwide avoided costs for subtransmission, substation, and local distribution (Table 7). PG&E calculates transmission, primary distribution capacity, and secondary distribution capacity avoided costs for each of 18 distribution planning areas (Table 8).

Annual $/kW-year T&D avoided costs for the three utilities are allocated to the hours of the year during which the system is most likely to be constrained and require upgrades—the hours of highest local load using a peak capacity allocation factor (PCAF) method.[27] Because local distribution loads are highly weather dependent, the PCAF is calculated individually for each of 16 climate zones in California.[28]

**Table 7. T&D Capacity Costs for SCE and SDG&E (SCE 2017 and SDG&E 2016)**

| | SCE | SDG&E |
|---|---|---|
| ***Marginal cost year*** | *2018* | *2016* |
| **Subtransmission ($/kW-yr)** | 40.00 | 0.00 |
| **Substation ($/kW-yr)** | 25.00 | 22.05 |
| **Local Distribution ($/kW-yr)** | 102.90 | 77.97 |

**Table 8. Range of T&D Capacity Costs for PG&E across 18 Distribution Planning Areas (2017 base year) (PG&E 2017)**

| Transmission $/ kW-yr | Primary Capacity $/ kW-yr | Secondary $/kW-yr |
|---|---|---|
| 7.71 | 13.63–73.97 | 0.97–1.75 |

**Avoided Cost Calculator**

The Avoided Cost Calculator is used in CPUC cost-effectiveness proceedings for demand-side resources (CPUC 2019a). The tool includes a system average distribution marginal cost value from the general rate case marginal cost of service filing for each California regulated utility. The calculator is used to value all DERs on a consistent basis and largely focuses on utility systemwide values. The tool produces an hourly set of values over a 30-year horizon that represent costs the utility would avoid if demand-side resources[29] produce energy in those hours.

The CPUC updates the calculator annually to improve accuracy of DER cost-effectiveness evaluations. The most recent update was completed in June 2020; it focused on aligning avoided cost calculations more directly with the CPUC Integrated Resource Planning process, including a transition to using production simulation modeling as the primary method of estimating future electricity system costs (E3 2020). These avoided costs are the benefits used in determining the cost-effectiveness of demand-side resources.

The calculator's avoided cost outputs are used as the benefit inputs for various DER program evaluation tools. For instance, energy efficiency programs are evaluated with the Cost-Effectiveness Tool, demand response programs are evaluated with the Demand Response Screening Template, and storage programs are evaluated using RESOLVE, a proprietary resource investment model, in the Self-Generation Incentive Program (CPUC 2019b; CPUC 2019c; E3 2019c; CPUC 2019d).

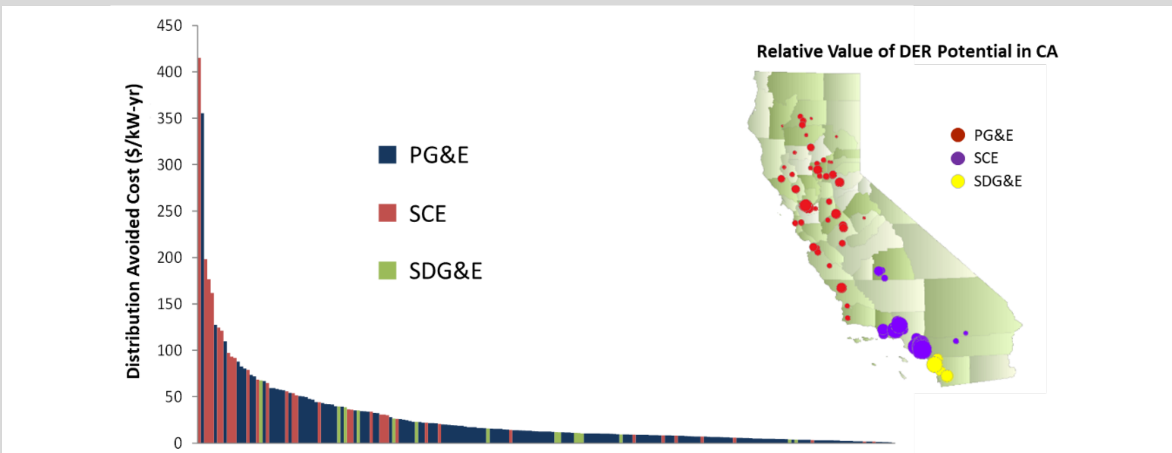
[27] The PCAF method assigns capacity value to the top load hours of the year (e.g., the 100 or 150 hours with highest annual loads) proportional to the load in those hours.
[28] See 2019 CPUC Avoided Cost Update documentation below.
[29] Energy efficiency, demand response, distributed generation (e.g., solar PV and fuel cells), and energy storage programs.

**Locational Net Benefit Analysis**

Nearly a decade later, in 2013, the California Legislature required utilities to propose a new distribution planning framework to "integrate cost-effective distributed energy resources" and "identify optimal locations for the deployment of distributed resources."[30]

**Area-Specific Avoided Distribution Costs**

Estimating area-specific avoided distribution costs requires granular data such as utility investment plans at the planning area level and hourly load profiles at the substation level. The figure below shows the range of annualized local distribution avoided costs by area using California utility distribution planning information. This research demonstrates that there are high value locations across the state, but that DERs must be targeted to capture the highest value. Results from other studies show a similar pattern when a utility's full set of distribution capital expansion plans are analyzed.




Distribution Avoided Costs Vary: California Example (E3 2011a)

In 2014, the CPUC instituted a rulemaking (R.14-08-013) to develop DRPs (CPUC 2014a), resulting in a requirement for regulated utilities to file DRPs that systematically evaluate potential distribution system investments and issue RFOs for local capacity resources that could competitively provide the necessary distribution system support. The DRP is the primary vehicle for advancing locational net benefits analysis (LNBA) in California. The CPUC sought to use the DRP proceeding to gain consensus on a consistent LNBA methodology to be used in distribution system planning and three other areas: integration of DER proceedings, development of a net-energy metering tariff successor, and integrated resource planning (CPUC 2014b).

The CPUC set forth a series of working groups, white papers, and tool development activities related to identifying and valuing opportunities for DERs to cost-effectively defer or avoid traditional utility

[30] Perea, H. 2013. AB 327.

investments planned to mitigate forecasted distribution system deficiencies. In the DRP working group, the utilities developed an Excel spreadsheet tool and methodology for LNBA using the present worth method to quantify DER distribution deferral value. For each location with a deferral opportunity, the load growth, load shape, and system need are defined, and the cost, size, and type of traditional distribution upgrade required are specified. The LNBA tool uses these inputs, as well as CPUC-approved avoided costs, to calculate the $/kW-year value of the deferral that could be achieved with DER deployment.

Using stakeholder input from the DRP proceeding, in 2017 CPUC staff developed the Distribution Investment Deferral Framework (DIDF), which formalizes the approach for the utilities to incorporate DERs in distribution system planning (CPUC 2017). The central objective of the DIDF is to identify and capture opportunities for DERs to cost-effectively defer or avoid utility investments planned to mitigate forecasted distribution system deficiencies.

**Sufficient Time Needed to Plan Non-Wires Alternatives**

The lead time required for new transformers or other major distribution system equipment can exceed one or two years. Based on utility experience to date, it may take one to three years from concept to operation to put NWAs in place. Thus, utilities are considering NWAs from 18 months to 60 months in advance of need, depending on the project size (EPRI 2019).

Case studies in this report on New York, California, and Nevada provide examples of suitability criteria for NWAs that take these time frames into account.

The DIDF requires the utilities to file annually a grid needs assessment (GNA) and distribution deferral opportunity report (DDOR).[31] Each utility performs a GNA that provides the available capacity, projected baseline DER deployment, and forecasted load growth for the next five years at every distribution feeder and substation bank. The DDOR summarizes all the planned investments needed to address deficiencies identified in the GNA. Together, the studies evaluate distribution capital deferral opportunities through a systematic process with stakeholder involvement.

The LNBA tool (see text box below) is used to calculate a $/kW-year value for each proposed investment in the DDOR. The utilities use an approved set of deferral screening criteria to identify a subset of those planned investments that are potentially deferrable with DERs. A technical screen identifies upgrades associated with four key distribution services that DERs can provide: distribution capacity, voltage support, reliability, and resiliency (CPUC 2016). In addition, a timing screen is applied to ensure that cost-effective DER solutions can be procured with sufficient time to fully deploy and begin commercial operation in advance of the forecast need date. Distribution upgrades that pass the

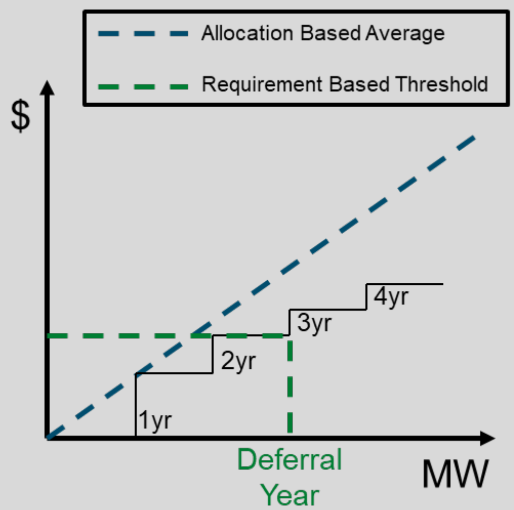
[31] D.18-02-004 initially directed the IOUs to file annual GNAs and DDORs by June 1 and September 1, respectively. This was modified in May 2019 (in response to IOU motions), consolidating the requirement into a combined annual GNA/DDOR filing to be submitted by August 15 each year. See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M288/K311/288311944.PDF.

screening process are identified as candidate deferral opportunities, each listed with a $/kW-year value calculated with the LNBA methodology.

**California's Locational Net-Benefit Analysis Tool**

California's LNBA tool estimates the avoided cost of distribution capital upgrades for assessment of targeted DERs. The tool uses the present worth method described in detail in Section 3.2 to compare the value of DERs to a specific utility investment. That is in contrast to the systemwide marginal cost of service method used in the Avoided Cost Calculator for assessment of systemwide DER programs. In addition to locational value, the LNBA tool includes the other components of avoided costs from the Avoided Cost Calculator (e.g., energy, system generation capacity).

The tool enables portfolio analysis for a suite of DER technologies targeted to a local distribution area. The figure below illustrates two options for performing the peak reduction and deferral valuation. The blue line illustrates the method used to derive an allocation based average, and the green line illustrates the method used to derive a requirement-based threshold.




LNBA Methodologies for Determining Peak Reduction and Deferral Valuation

The allocation-based average method quantifies the peak load reduction from a DER project and multiplies it by the utility's system average distribution avoided costs (in $/kW-yr), essentially taking a point along the blue dashed line in the figure. There are many ways to arrive at the unit cost. Common approaches include using values published in the utility's most recent general rate case or using average distribution project upgrade costs assuming a particular deferral year.

The requirement-based threshold method is more detailed. It compares peak load before and after a potential DER project to determine the deferral upgrade year for the specific project, which is then used to calculate the project's deferral value (green dashed line).

For example, in 2019 PG&E evaluated 4,269 circuits in its GNA and found 6,994 "needs" for upgrades (PG&E 2019a). With respect to projects to meet these needs, 797 were related to distribution capacity, 6,153 to voltage support, and 44 to reliability. The utility's GNA includes the impact of future planned load transfers and switching operations that mitigate the identified need without additional upgrades. After load transfers, PG&E identified 215 planned investments for substation, feeder, and distribution line sections to mitigate the remaining needs (one project can mitigate multiple needs) (PG&E 2019b). Of those projects, 18 passed PG&E's technical and timing screens and are candidate deferral opportunities. These are prioritized in three tiers with total capacity as follows:

- Tier 1 (most likely to be deferred): three projects, totaling 18.5 MW
- Tier 2 (closely monitored for future deferral potential): three projects, totaling 2.9 MW
- Tier 3 (not likely deferrable with a DER solution): 12 projects, totaling 66.9 MW

In addition to filing annually a combined grid needs assessment and distribution deferral opportunity report (DDOR), each utility presents recommended projects for NWA solicitations to the Distribution Planning Advisory Group for consideration. Table 9 lists several examples of potential NWA opportunities identified by the utilities in their 2018–2019 DDOR. After identifying deferral opportunities, the utilities issue RFOs for NWAs. The RFOs include project and location specific value that is based on the present worth method in the LNBA tool. The LNBA tool is used to evaluate all NWA proposals submitted in response to the RFOs.

**Table 9. Example California NWA Opportunities (PG&E 2018; PG&E 2019b; SCE 2018, SDG&E 2018a)**

| Utility | Project Name | Size of Need | Need | Year Needed | LNBA Value ($/kW-Yr) |
|---|---|---|---|---|---|
| **PG&E** | El Nido Bank 1 Replacement | 1.69 MW | Capacity | 2020 | 115 |
| | Oceano 1106 | 1.2 MW | Replace underground cable Reliability/other | 2022 | 64 |
| | Gonzales | 2 MW | Capacity | 2021 | 100–500 |
| **SCE** | Sun City 115/12 kV Substation #1 and #2 | Install a 12 kV circuit at each substation | Increase substation capacity due to demand growth | 2022 | 0–100 |
| | Mira Loma-Jefferson Line Licensing | Install two 12 kV circuits | Underground cable temperature limits expected to be exceeded | 2021 | >500 |
| **SDG&E** | Cannon C783 | 21 amp | New conduit, sectionalizing thermal backtie | 2019 | 0–100 |
| | Jamacha B30 | 1.4 MW | New substation bank transformer | 2020 | 0–100 |

The CPUC approved a utility regulatory incentive mechanism pilot for PG&E, SCE, and SDG&E (Decision D.16-12-036, CPUC 2016). Each utility selects one to four projects to validate the ability of DERs to defer or avoid investments in traditional distribution infrastructure and achieve net ratepayer benefits, as estimated by the LNBA. Each IOU held a competitive solicitation for NWAs, evaluated the proposed DER projects, obtained CPUC approval for the selected project(s), and provided status reports (CPUC 2016). Utilities were eligible for a 4% pre-tax incentive, applied to the annual payment for DERs. The incentive was recoverable if the procured DERs successfully avoided or deferred an otherwise planned utility expenditure. Incentives ended when the deferral period ended and the utility made a traditional investment (CPUC 2016).

PG&E and SDG&E reported that they did not receive any cost-competitive bids in their Incentive Pilot solicitation.[32] Therefore, neither PG&E nor SDG&E completed an Incentive Pilot project (CPUC 2018a; CPUC 2018b). SCE pursued an Incentive Pilot project to demonstrate that smart inverters in residential solar PV systems could regulate voltage by providing reactive power, but unknowingly implemented the pilot on a distribution system that did not need voltage regulation support and was unable to complete the analysis (SCE 2019).

PG&E did conduct an Integrated DER Incentive Pilot Candidate Project at its Gonzales Substation, which has a projected 2 MW deficiency in 2021 (PG&E 2018). PG&E issued an RFO and selected 1 MW and 1.75 MW storage projects (PG&E 2019c). PG&E reported several major lessons learned so far in the development of the pilot to date, such as the uncertainty that exists in load forecasts and the importance of both direct and indirect impacts of changes to loads for assessing the validity of DERs to defer distribution upgrade projects (PG&E 2018).

**Rates**

There are two examples of location-specific charges in retail rates in California—one for vehicle grid integration and one for public grid integration. Both are from SDG&E. The SDG&E Vehicle Grid Integration rate (also known as the "Power Your Drive" pilot) is an ongoing pilot program that began in April 2017; SDG&E submitted an application for additional funding in October 2019. SDG&E's separate Public Grid Integration rate became effective in December 2018 (SDG&E 2017, SDG&E 2018b). The rates are similar in their design; both have a base rate established for all hours of the year and three additional components (e.g., adders). An hourly energy adder is established one day in advance based on CAISO day-ahead energy prices. SDG&E also sets each of two capacity adders one day in advance. A distribution capacity cost adder is added for up to 200 local peak demand hours—providing a location-specific component to the rate—and a system capacity adder is added for up to 250 system peak demand hours.

[32] A recent Wood Mackenzie study found that NWA projects only go forward 40% of the time, primarily due to cost and reliability. See GTM. 2020. "US non-wires alternatives H1 2020: Battery storage seizes top spot as utilities' preferred non-wires resource." Broad disclosure of NWA opportunities provides useful information for interested third parties, such as DER providers, utilities, and regulators. At the same time, this broad disclosure dilutes the share of NWA projects progressing toward implementation.

**Hosting Capacity Analysis**

In 2017, a CPUC working group identified two primary use cases for hosting capacity analysis, called *integrated capacity analysis.* The first and most developed use case is to improve interconnection, which includes a more automated and transparent interconnection process and publication of data that helps customers design systems that do not exceed grid limitations. The second, and currently less developed, use case is to *inform distribution planning processes* by helping to identify how to better integrate DERs into electricity systems. Working group-proposed refinements and improvements to the analysis are under consideration at the CPUC.

## 5.2 District of Columbia[33]

The District of Columbia (DC) PSC opened its "Modernizing the Energy Delivery System for Increased Sustainability" (MEDSIS) proceeding in 2015 and developed a vision statement in 2018. The Commission required utilities to "develop detailed, data-driven Distribution and Integrated Resource Plans that, among other things make infrastructure planning cost-effective; enable the optimal combination of distributed energy resources (DERs) with traditional capital investment by exploring non-wires alternatives; comply with legislatively mandated deployment of DER in the District; permit rational participation of consumers and distribution service providers; and plan for, track, and monitor DER penetration rates on the grid" (DC PSC 2018).

The vision statement informed subsequent working groups for the proceeding, including one focused on NWAs. The NWA working group scope included addressing questions relevant to locational value:[34]

- What are the consistent and verified processes, tools, and information requirements for planning NWAs to grid investments in the District?
- What are the existing methodologies and frameworks that best assign and evaluate the benefits and costs of DERs for NWAs?

The NWA working group process ended in 2019 with the preparation of a report containing learnings and recommendations to the DC PSC (SEPA 2019) (Figure 14). Regarding tools for NWA analysis and valuation, the working group agreed that benefit-cost analysis is critical and that the DC PSC and stakeholders require further work to develop a methodology for valuation of NWAs, including their location-specific value (SEPA 2019).

[33] Asa Hopkins, Synapse Energy Economics, Inc., prepared this case study.
[34] The MEDSIS NWA Working Group website: https://dcgridmod.com/?page_id=40.

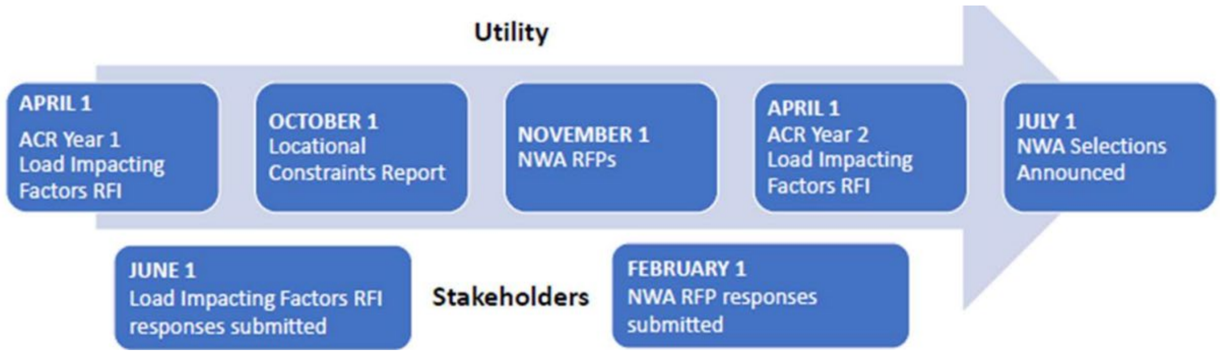



**Figure 14. Proposed DSP and NWA Process**

Note: ACR - Annual Consolidation Report.[35]
Source: Pepco, in SEPA (2019).

To date, the District has not developed or adopted a consistent approach to locational value or NWA assessment. The MEDSIS NWA working group devoted most of its effort to higher-level questions and did not reach consensus about which of the tools and methods it examined were the best for the District. The working group's report demonstrates both the interest in and need for further work to develop a consistent benefit-cost approach.

On July 1, 2020, Pepco filed a draft outline of a benefit-costs analysis handbook for NWAs with DC PUC and made the handbook available to stakeholders in November (PEPCO 2020a, PEPCO 2020b). However, until or unless Pepco's BCA handbook is adopted as an official methodology, *ad hoc* analyses will remain the primary option for valuing DERs as grid assets.

## 5.3 Hawaii

Hawaii began investigating DER policies and grid modernization in 2014 when the Public Utilities Commission opened Docket 2014-0192[36] and issued the *Commission's Inclinations on the Future of Hawaii's Electric Utilities.* This document provided goals to guide the electric utilities in Hawaii, including:

- Lower, more stable electric bills
- Expanding customer energy options
- Maintaining reliable energy service in a rapidly changing system operating environment

The document also offered three pillars for the utilities' strategy, energy resource planning, and project review:

- Creating a 21st Century Generation System

[35] The ACR includes the Comprehensive Plan for the Planning, Design, and Operation of the Distribution System, the Productivity Improvement Plan, and the annual Manhole Event Report. For example, see Pepco's 2020 report: https://edocket.dcpsc.org/apis/api/filing/download?attachId=103174&guidFileName=bbeb6037-5efa-4f2a-bf1f-dd5de5dd7f75.pdf.
[36] For more information on Hawaii's grid modernization strategy and policy background see Homer et al. (2017) and Cooke, Homer, and Schwartz (2018).

- Creating Modern Transmission and Distribution Grids
- Policy and Regulatory Reforms to Achieve Hawaii's Clean Energy Future

As part of implementing these strategies, in 2017 the Commission required the Hawaiian Electric Companies (HECO) to file a holistic, scenario-based Grid Modernization Strategy.[37] In 2018, the Commission accepted HECO's Integrated Grid Plan.[38] Following the order, HECO submitted an Integrated Grid Planning Workplan which was accepted by the Commission in 2019. One of the workplan's products was a soft launch to allow the companies to "demonstrate the sourcing processes and evaluation methods for distribution NWAs" through a request for proposals.[39] The RFP was closed in January 2020 (see the HECO case study in Chapter 6). The soft launch allowed HECO to work with the Integrated Grid Planning Distribution Working Group to "document the NWA Opportunity evaluation process, criteria and rationale" and "document related NWA information requirements incorporating stakeholder feedback."[40]

Rather than develop planning estimates of the locational value of NWAs to meet grid service needs, HECO simply issues solicitations for grid services from customer-sited DERs.[41] For the soft launch in HECO's integrated grid planning process, only non-wires solutions were considered through the RFP. Both Wires Solutions and Non-Wires Solutions are evaluated through RFPs for additional identified grid needs. That also is the case for future resource selection in the integrated grid planning process, which will consider pricing, program, and procurement solutions (Figure 15).

[37] Docket No. 2017-0226. https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/dkt_2016_0087_20170104_order_34281.pdf.

[38] Hawaiian Electric. What is Integrated Grid Planning? https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning.

[39] Hawaiian Electric Company Request for Proposals for Non Wires Alternatives to Provide Reliability (Back-Tie) Services Island of O'ahu East Kapolei Area. Docket 2018-1065. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/20191108_igp_soft_launch_rfp_with_appx_a-j.pdf.

[40] Hawaiian Electric. 2019. Distribution Planning Working Group Deliverables and Hosting Capacity Improvements. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20191204_dpwg_meeting_presentation_materials.pdf.

[41] Hawaiian Electric. Demand Response. https://www.hawaiianelectric.com/products-and-services/demand-response/rfp-for-grid-services-from-customer-sited-distributed-energy-resources.

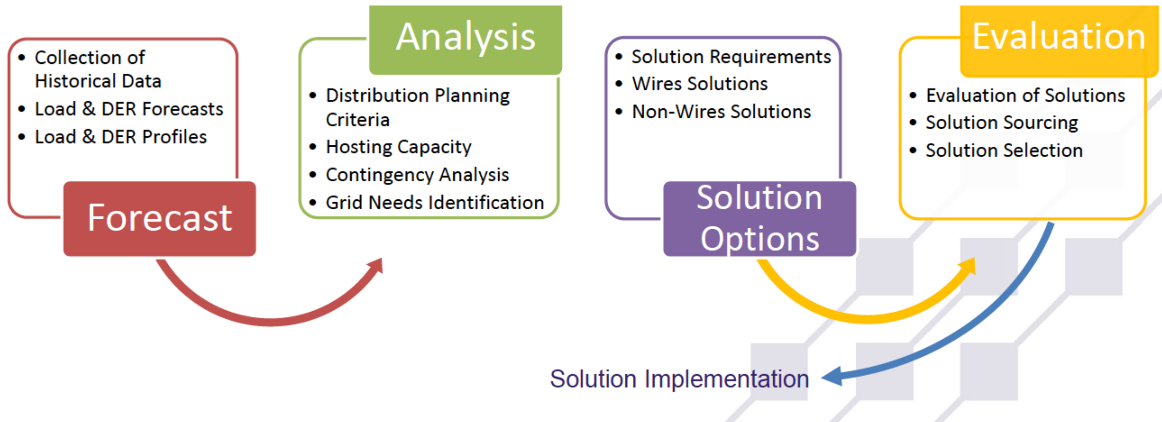



**Figure 15. Integrated Grid Planning in Hawaii**
Source: HECO presentation to Puerto Rico Energy Bureau, January 10, 2020

The company uses a competitive RFP process to procure grid services including capacity and ancillary services, such as services to support contingency reserves.[42] HECO evaluates the competitive bids, ranking and scoring all proposals with a 50/50 weighting for price and non-price criteria. The price criteria consist of a $/kW cost for each grid service on each island. The three most important non-price criteria are: (1) conformance with the utility's Code of Conduct standards, (2) conformance with information assurance policies, and (3) participant acquisition strategy. HECO selects a short list of the highest ranked proposals, then solicits best and final offers from proposers.[43]

## 5.4 Maine[44]

Three pieces of legislation and corresponding regulatory proceedings have influenced how the locational value of DERs is considered in Maine.

In 2010, the Maine Legislature passed the *Smart Grid Policy Act*, which directed Maine's Public Utilities Commission (PUC) to investigate creating the role of a smart grid coordinator.[45] One potential responsibility of the smart grid coordinator was exploring non-transmission alternatives. [46]

In 2013, the legislature passed a wide-ranging energy bill that included amended and new provisions related to the consideration of non-transmission alternatives in the approval requirements for transmission projects (Maine 2013). The new law required an investigation by an independent third party (either the PUC itself or a contractor to the PUC) on considering demand-side alternatives for this purpose. The new law also established a preference for non-transmission alternatives "able to address

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[42] Hawaiian Electric Companies' Phase 2 Draft Requests for Proposals. 2019. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/producing_clean_energy/competitive_bidding/20190401_phase_2_draft_rfp_book_3.pdf.
[43] Ibid.
[44] Melissa Whited, Synapse Energy Economics, Inc., prepared this case study and associated text in Appendix E.
[45] A *smart grid coordinator* is defined as an entity "that manages access to smart grid functions and associated infrastructure, technology and applications within the service territory of a transmission and distribution utility" (35-A M.R.S.A. § 3143(1)(B)).
[46] Maine processes originally referred to NWAs as "non-transmission alternatives" or NTAs. This changed to NWAs beginning around 2017 and was codified in the 2019 law that explicitly addresses distribution investments and adopts the more general NWA language.

the identified need for the proposed transmission line at lower total cost to ratepayers in this State" and a requirement for "specific findings" by the PUC with regard to non-transmission alternatives (Maine 2013).

In 2019, the Legislature gave the state's Office of the Public Advocate a new responsibility: coordinating analysis of NWAs. The law (Maine 2019) essentially overturned a previous PUC ruling that the utilities should be responsible for non-transmission alternatives (Maine PUC 2017) and instead gave the Office of the Public Advocate the authority and responsibility to contract with an entity to act as the "nonwires alternative coordinator." This role includes:

- Reviewing transmission and distribution project planning studies
- Investigating and making recommendations regarding NWAs in lieu of utility capital investments in the transmission and distribution system
- Conducting benefit-cost analyses of NWAs and making recommendations regarding NWAs and their procurement
- Tracking implementation of NWAs

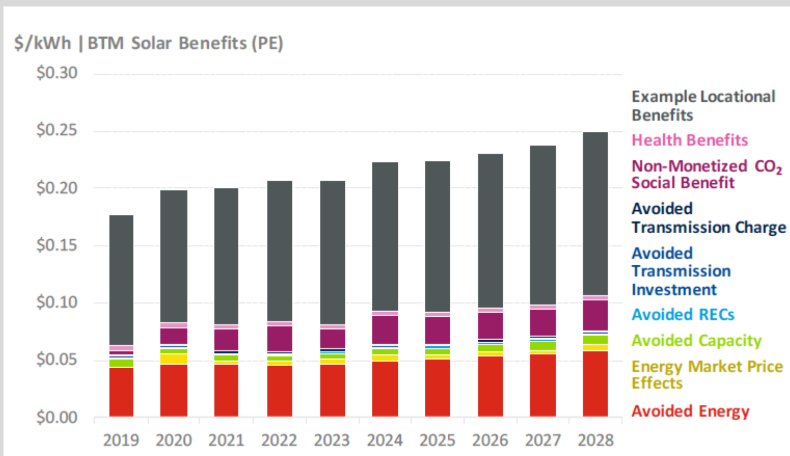
When a utility proposes a traditional investment, the law requires that the PUC weigh the cost-effectiveness of the wires and non-wires options presented, and then give preference to NWAs that are the most cost-effective. The law specifies that cost-effectiveness be evaluated using a Utility Cost Test (including any value from deferral of the wires investment), and not include any participant contributions to the cost of the alternative. The NWA coordinator uses avoided costs that are generally consistent with those used by the Efficiency Maine Trust for efficiency cost-effectiveness screening. The law also establishes that once the PUC determines any front-of-meter NWA is appropriate, the utility must procure it. Efficiency Maine Trust, the third-party administrator for energy efficiency programs in the state, acquires the behind-the-meter NWAs. Either the utility or a third party may deliver grid-side solutions, such as storage or generation connected directly to the utility system. There is no provision for financial or performance incentives for the utility. Chapter 6 includes Maine utility case studies.[47]

[47] Also see MPUC dockets 2019-00309 and 2011-00138 for recent filings on current analyses by the NWA coordinator.

**Value of Solar Tariffs and Studies**

Some states have developed Value of Solar tariffs as an alternative to net energy metering for distributed solar. These tariffs may consider locational value, based on studies conducted for the utility's service area.

For example, the Maryland Public Service Commission initiated a proceeding in 2016 (PC44) to review electric distribution systems, targeting issues that maximize benefits and choice to the state's electric customers. As part of the proceeding, a Commission consultant identified the state-specific benefits and costs of distributed solar resources for customers, including consideration of geographic and grid location. The study defined locational benefits as "the savings benefits would be realized on that circuit or feeder experiencing the savings but not throughout the entire distribution system uniformly" (Daymark Energy Advisors 2018). The graph below, from the final report on the study, illustrates the increasing value of locational benefits by year. According to the report, a 2 MW project that avoids a $2 million distribution investment could provide $0.11/kWh in additional locational benefits.




Value of Behind-the-Meter Solar Including Locational Benefits:
Potomac Edison Service Area

## 5.5 Massachusetts

Massachusetts requires each electric distribution company to develop and implement grid modernization plans. Prescriptive requirements include feeder characteristics; the number, ownership, type, and capacity of DERs for each feeder; the percent of DER capacity to feeder peak load; and estimated energy output by DER type and ownership (e.g., utility, customer, third party) (Massachusetts DPU 2013). Currently, grid modernization plans do not have a locational value calculation requirement. However, House Bill 4857 (2018) allows electric distribution companies to hold competitive solicitations to procure NWAs from third party developers for transmission or distribution system solutions (Massachusetts General Law 2018). In evaluating bids, electric distribution companies must consider monetary and non-monetary factors. National Grid has one upcoming RFP opportunity for an NWA project in Massachusetts.[48]

[48] See National Grid. https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/Opportunities.

## 5.6 Michigan

In general rates cases for three regulated electric utilities, the Michigan Public Service Commission ordered filing of initial five-year distribution investment and maintenance plans to increase visibility system needs and acquire a more thorough understanding of anticipated needs, priorities, and spending. Consumers Energy and DTE file their first distribution system plans in 2018. In a subsequent order, the Commission required the utilities to perform hosting capacity studies and participate in a technical conference to develop a common cost-benefit methodology, which included a discussion on criteria for NWA analysis (MI PSC 2020). Indiana and Michigan Power (I&M) filed its first distribution system plan in 2019. The Commission consolidated all of these filings into a distribution system planning docket.[49]

PSC staff held several stakeholder meetings on Electric Distribution Investment and Maintenance Plans. Two of the meetings discussed NWAs. The first meeting had presentations from experts on NWAs, and in the second meeting, utilities discussed hosting capacity analysis and NWA plans (MI PSC 2020). Following all of the stakeholder meetings, staff filed a report in April 2020 with recommendations to the Commission (MI PSC 2020).[50]

Another report by PSC staff, the *Michigan Statewide Energy Assessment*, includes the following recommendations for utilities:[51]

- "better align electric distribution plans with integrated resource plans to develop a cohesive, holistic plan and optimize investments considering cost, reliability, resiliency, and risk. As part of this effort, Staff, utilities, and other stakeholders should identify refinements to IRP modeling parameters related to forecasts of distributed energy resources (e.g., electric vehicles, on-site solar), reliability needs with increased adoption of intermittent resources, and the value of fuel security and diversity of resources in IRPs. A framework should also be developed to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans."
- "work with Staff and stakeholders to propose a methodology to quantify the value of resilience, particularly related to DERs. In addition, the value of resilience should be considered in future investment decisions related to energy infrastructure in future cases."

Utilities must file their next distribution system plans in final form by September 30, 2021, consistent with updated Commission guidance.[52] The plans will articulate the utilities' decision criteria to screen

[49] Case No. U-20147; https://mi-psc.force.com/s/case/500t0000009gHerAAE/in-the-matter-on-the-commissions-own-motion-to-open-a-docket-for-certain-regulated-electric-utilities-to-file-their-distribution-investment-and-maintenance-plans-and-for-other-related-uncontested-matters.
[50] For more information, see Michigan PSC's website on distribution planning: https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93320_94544-508710--,00.html.
[51] *Michigan Statewide Energy Assessment.* 2019. https://www.michigan.gov/documents/mpsc/2019-09-11_SEA_Final_Report_with_Appendices_665546_7.pdf.
[52] August 20, 2020, order in Case No. U-20147: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000DcfWRAAZ.

projects for NWA analysis and consider pilots for DERs beyond energy efficiency and demand response. (Chapter 6 includes Michigan utility case studies to date.) Specifically, the Commission expects the plans to include such information as NWA costs and savings, impacts on customer consumption patterns and offsetting the need for traditional investments, implementation timing, and assumptions used, including minimum customer participation levels for NWA solutions. In addition, the Commission confirmed the proposed definition of *locational value assessment*: "intended to quantify the benefits and costs of DER, which are often locational in nature" (ICF 2018).[53] Based on discussion in a staff-led stakeholder group on the integration of resource, distribution, and transmission planning, staff will file by May 27, 2021, findings and recommendations relating to methodologies or frameworks for evaluating NWAs.[54]

## 5.7 Minnesota

State law requires the state's largest utility, Xcel Energy, to submit biennial T&D plans to the Public Utilities Commission (PUC) to "identify…investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies." The utility also must analyze hosting capacity for small-scale distributed generation resources to "identify necessary distribution upgrades to support [their] continued development." [55]

The PUC requires Xcel Energy to file Integrated Distribution Plans annually and smaller utilities to file every two years (MN PUC 2018 and 2019). Among the requirements are projecting distribution system spending for five years into the future, itemizing any non-traditional distribution projects (which includes NWA analysis).

Utilities also must provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years anticipated to cost more than $2 million and an analysis comparing NWAs to these projects in terms of viability, price, and long-term value. Other required NWA-related information includes:

- Suitability criteria, including project type (such as load relief or reliability), timeline needed to consider NWAs, and minimum project cost
- A proposed screening process to determine that NWAs are considered prior to the utility making distribution system investments

Xcel Energy filed its second integrated distribution plan in November 2019, indicating that in future analysis the utility would consider locational net benefits analysis. In its 2019 plan, Xcel Energy

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[53] ICF 2018.
[54] August 20, 2020, order in Case No. U-20633: https://mi-psc.force.com/sfc/servlet.shepherd/document/download/069t000000CqeOoAAJ?operationContext=S1.
[55] Minn. Stat. §216B.2425 (2015). https://www.revisor.mn.gov/statutes/cite/216B.2425.

reviewed the viability of using a portfolio of demand response, storage, and solar as NWAs for nine distribution system projects. The utility's analysis found that using traditional wired solutions cost significantly less than estimated costs for NWAs for all nine projects (Xcel Energy 2019).

## 5.8 Nevada

In 2017, the Nevada Legislature passed legislation requiring utilities to submit a Distributed Resource Plan (DRP) to the Public Utilities Commission of Nevada (PUCN) by July 2019, and every three years thereafter, as part of its resource plan.[56] Among other provisions, the legislation requires that DRPs evaluate locational benefits and costs of distributed resources (distributed generation systems, energy efficiency, energy storage, electric vehicles, and demand response technologies).

In 2019, the PUCN approved final regulations (Docket 17-08022) specifying DRP requirements for, among other things, NWA analysis, and locational net benefit analysis. The forecast and hosting capacity analyses inform a grid needs assessment that forms the basis for "recommendations for the deployment of utility infrastructure upgrade solutions and non-wires alternative solutions to identified constraints." The regulations specify that utilities may recover all prudently and reasonably incurred costs of carrying out an approved DRP, in a separate rate proceeding.[57]

**Locational Net Benefit Analysis**

The LNBA is defined as "a cost-benefit analysis of distributed resources that incorporates location-specific net benefits to the electric grid."[58] The LNBA is used to: (1) evaluate the economics of deploying distributed resources at different locations on the electric system, (2) evaluate the potential of distributed resources to defer traditional infrastructure upgrades, (3) understand the impact of distributed resources on long-term system needs related to load growth and reliability, and (4) inform the procurement process for non-wires solutions (NV Energy 2019).

PUCN requirements require that the following factors be considered when conducting an evaluation of locational costs and benefits:

- "Reductions or increases in local generation capacity needs
- Avoided or increased localized investments in distribution infrastructure
- Reductions to or increases in safety benefits of the electric grid
- Reductions to or increases in the reliability benefits of the electric grid
- Other localized savings that distributed resources provide to the electric grid
- Other costs that distributed resources impose on customers of the electric utilities."[59]

[56] SB 146: https://www.leg.state.nv.us/App/NELIS/REL/79th2017/Bill/4982/Overview.
[57] Docket 17-08022. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2017-8/41440.pdf.
[58] "Locational net benefit analysis" defined. https://www.leg.state.nv.us/nac/NAC-704.html#NAC704Sec9109.
[59] NAC 704.9237. Requirements and contents of distributed resources plan. https://www.leg.state.nv.us/nac/NAC-704.html#NAC704Sec9237

**Value of Distributed Generation – New Hampshire**

In 2019, the New Hampshire Public Utilities Commission approved a scope and timeline for a locational value of distributed generation study and directed Commission staff to issue an RFP to perform the study (NH PUC 2019). The scope of work was awarded to a consultant. The report will "consider the value of avoided or deferred distribution investment costs due to capacity constraint elimination at a number of locations on the New Hampshire electrical distribution grid." Resources that are not eligible for net metering, such as efficiency and demand response, are excluded from the scope of the study, as are "potential avoided or deferred distribution costs related to power quality and lower distribution elements, including distribution transformers and capacitor banks."

## 5.9 New York

New York was an early proponent of quantifying the locational value of DERs for NWA evaluation, and more recently for use in compensating DERs and tariff design. The New York Public Service Commission (NY PSC) has required electric utilities to evaluate DERs as an alternative to transmission and distribution capital projects since industry restructuring in the late 1990s.

The NY PSC elevated locational value analysis as part of the Reforming Energy Vision (REV) proceeding launched in 2014.[60] The proceeding established mechanisms to transform the state's energy grid into a more dynamic and integrated distributed system platform, with greater transparency and visibility into how utilities operate the grid, plan for system needs, and compensate DERs. The state is working to use markets and prices to encourage investment in DERs and to compensate DERs for the services that are provided, including through granular, location-based price signals and avoided cost methodologies. The REV proceedings are organized into two tracks, discussed in the text box below.

Table 10 summarizes four key areas where load-serving entities in New York are required to integrate the locational value of DERs: (1) DER program cost-effectiveness analysis that incorporates a value for avoided transmission and distribution capacity, (2) local area planning for NWAs to reduce utility capital expenditures, (3) rate-setting with either a dynamic distribution customer charge or dynamic DER compensation, and (4) hosting capacity analyses that provide information about the quantity of DERs that can be interconnected to various parts of the system without additional infrastructure investment.

[60] Reforming the Energy Vision (REV) establishes an overarching energy framework and strategy for New York state agencies, including the NY PSC. The objectives of REV are to develop a "clean, resilient, and more affordable energy system … while actively spurring energy innovation, bringing new investments into the State, and improving consumer choice." See https://www3.dps.ny.gov/w/pscweb.nsf/all/cc4f2efa3a23551585257dea007dcfe2.

**Table 10. Regulatory Framework for Location-Specific DER Valuation in New York**

| | |
|---|---|
| **Program Cost-Effectiveness** | The NY PSC publishes cost-effectiveness guidelines (NY PSC 2016a), and each utility produces a benefit-cost analysis handbook that details how DER procurements and programs will be evaluated. The handbook includes methodologies for locational values (e.g., translating marginal cost of service studies into local subtransmission and distribution values). |
| **Non-wires Alternatives** | Each utility files a Distributed System Implementation Plan (DSIP) biennially, including how they plan to integrate NWAs. For high opportunity areas identified in the DSIP process, the utilities issue non-wires requests for offers to procure distribution capacity. |
| **Rates and Tariffs** | The VDER tariff compensates DERs based on the value they provide to the grid, including the locational system relief value. New York utilities also have ongoing pilots of dynamic rates, including a distribution price in the Smart Home Rate Pilots. |
| **Hosting Capacity Analyses** | The Joint Utilities of New York developed a four-stage Hosting Capacity Implementation roadmap. To date, the utilities have developed Stage 2 hosting capacity maps focused on feeder-level analysis of large-scale solar PV systems interconnecting to distribution circuits 12 kV and above. |

**Reforming the Energy Vision**

New York PSC's REV Track 1 proceeding established a requirement for regulated electric utilities to file Distributed System Implementation Plans (DSIPs) every two years (NY PSC 2015). The plans provide a comprehensive and holistic view of each utility's distribution system and strategies to improve planning processes and decision-making. Utilities publicly post their plans, processes, and capabilities for evaluating T&D capital costs and identifying NWA opportunities.

The plans integrate locational attributes in two ways: (1) they require each utility to identify locations on its distribution system where DERs would be most valuable, and (2) they must identify where DERs could help alleviate distribution constraints, and where they have value for avoiding distribution infrastructure upgrades.

The REV Track 2 proceeding focused on a transition away from net energy metering through a new mechanism called the Value of Distributed Energy Resources (VDER) (NY PSC 2016b). A goal of the proceeding is providing meaningful price signals for DER investment and operation. The VDER tariff uses the utilities' marginal cost of service studies to define a *non-location-specific* demand reduction value and a higher *location-specific* reduction value. The location-specific value is added to the demand reduction value in utility-identified locally constrained areas. The NY PSC defined a process to update and refine the methodology for these values as more information is developed, including a methodology to calculate more spatially and temporally granular MCOS estimates.

## Benefit-Cost Analysis

In January 2016, the NY PSC established a benefit-cost analysis framework for utilities to evaluate the cost-effectiveness and joint economic and environmental consequences of resource proposals within the scope of the REV proceeding (NY PSC 2016a). The NY PSC requires utilities to apply the framework each time they “propose to make an investment that could instead be met through DER alternatives…. [I]t is anticipated that these projects will be solicited through a competitive procurement process” (NY PSC 2016a.

Specifically, the benefit-cost analysis is applied to five categories of utility expenditures: (1) investments in distributed system platform capabilities, (2) procurement of DERs through competitive selection, (3) procurement of DERs through tariffs, (4) energy efficiency programs, and (5) local transmission projects and distribution system upgrades. The benefit-cost framework requires that analyses “list all benefits and costs including those that are localized and more granular” (NY PSC 2016a).

The framework provides guidance for the sources of each category of benefits and costs. For example, the framework states that utilities should rely on their marginal cost of service studies to identify the costs of traditional local subtransmission and distribution projects that DERs can avoid or offset (i.e., methodologies for locational value). Each utility has developed and filed a benefit-cost analysis handbook that details its methodology for evaluating benefits and costs of DER investments, for the utility system and to society as whole.

**Non-Wires Alternative Solicitations**

New York utilities identify NWA opportunities in their DSIPs. The utilities’ initial DSIPs in early 2016 served as a source of public information regarding how utilities responded to and met emerging REV requirements. The DSIPs included information on the first NWAs to occur outside the rate filing process and plans to incorporate DER technologies. DSIPs submitted in 2018 provided more detail on each utility’s progress and next steps for implementation, particularly for NWA identification and procurement.

The New York utilities developed NWA Suitability Criteria in 2016 (along with other stakeholders) to identify viable opportunities for DER projects to defer or replace traditional solutions. The criteria are intended to screen projects for NWA suitability, as well as to help direct DER project developers to the opportunities that have the highest potential for success. Figure 16 shows an indicative NWA solicitation process used by the New York utilities. The process begins with the identification and quantification of system needs driving specific capital project plans, inclusive of timing and location. Traditional infrastructure projects which pass the suitability screening are considered candidates for NWA solutions, which are then shared with developers through a notification process (generally via posting on utility or New York state websites). Data for inclusion in project solicitations for these opportunities (e.g., RFPs) is then developed, including more precise definition of system needs. This process also prioritizes the NWA opportunities, using criteria such as timing of system needs. Finally, procurement of NWA solutions takes place through issuance of project solicitations, utility review of proposals, project negotiation, and awarding of contracts.

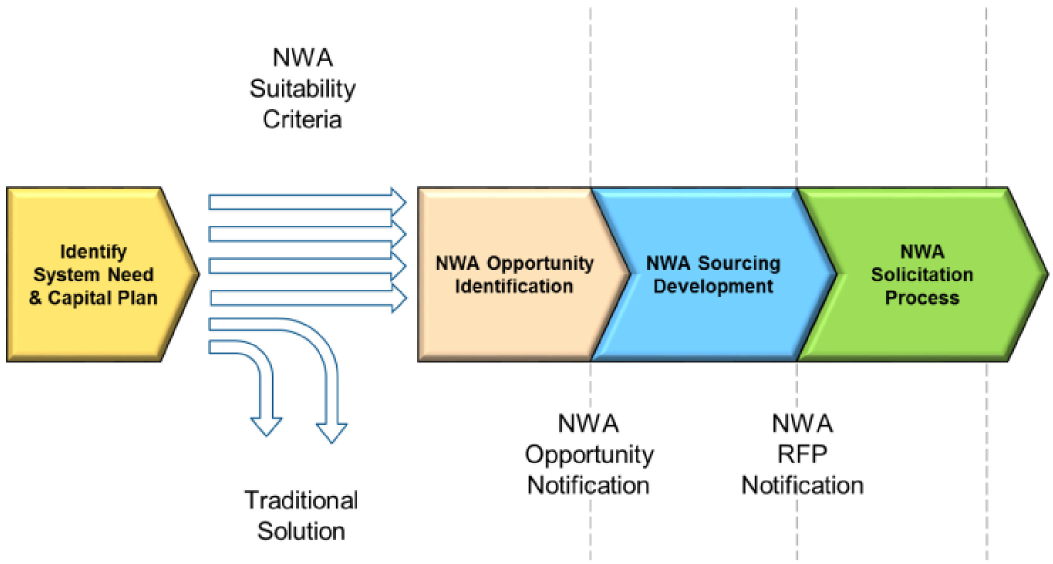



**Figure 16. New York's NWA Process**

Once the utility has received NWA proposals through competitive solicitations, the most promising portfolio of projects must be evaluated through the benefit-cost analysis framework to assess if a non-wires or traditional solution is best for the utility's customers. The framework uses the Societal Cost Test to evaluate portfolios. The Utility Cost test and Rate Impact Measure test can provide added information on utility costs and ratepayer bills.

The most recent DSIPs were submitted in June 2020. Table E-3 in Appendix E provides details on NWA procurement opportunities identified by each utility since 2016 (REV Connect 2019). These opportunities include using NWAs to alleviate overloaded feeders, substations, and transmission lines.

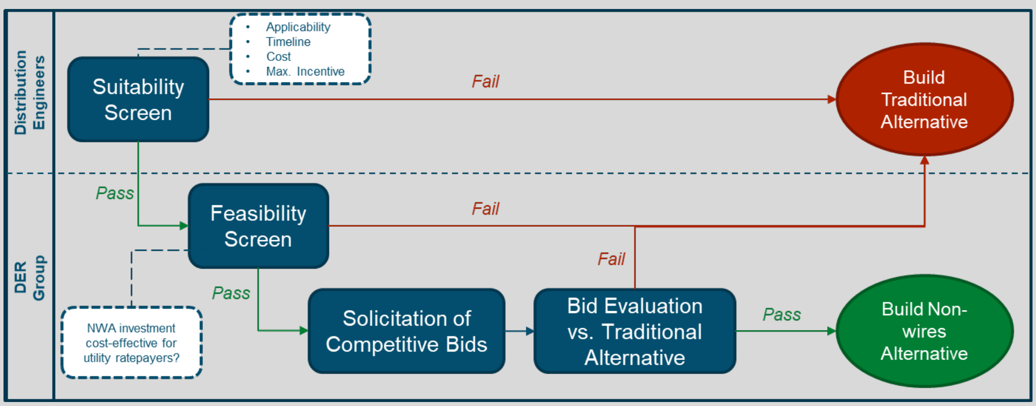
Utilities treat NWA expenditures as if they were capital expenditures, earning a return on spending. Utilities may also earn incentives for successfully completing NWA projects based on a share of the societal net benefits of implementing an NWA project instead of traditional utility capital expenditures.

**Competitive Procurement for Non-wires Alternatives**

Some utilities use a competitive procurement process for DERs to meet certain types of distribution needs to defer or potentially avoid a traditional utility solution.[61] Respondents may include demand response aggregators, energy storage project developers, and other energy services companies.

Utilities typically use a screening tool (see Appendix C) to work through key questions in an organized manner to determine which identified grid needs are suitable for NWAs (suitability screening criteria) at the beginning of the process. If the identified grid needs pass this suitability screen, the utility runs them through a feasibility screen to assess whether an NWA is likely to be cost-effective for utility customers. Historically, a separate DER group in the utility has been responsible for feasibility screening, rather than distribution engineers responsible for traditional distribution capacity projects; however, these tasks are increasingly integrated into regular planning processes.

As the figure below shows for New York utilities, the screening process allows distribution system planning staff to focus their analysis on areas with the greatest likelihood of success. This approach, combined with the broader set of integrated DER assessment tools described below, can identify areas that are good candidates for competitive procurement of non-wires solutions.




As detailed in Table E-3 in Appendix E, NWA projects proposed since the launch of REV have had mixed success. The majority of projects are still in the proposal evaluation/cost-benefit analysis stage. Some proposed projects have been canceled due to changing forecasts or a failure to pass cost-effectiveness tests. A handful of NWA projects are in active implementation or the final stages of contracting.

In the spring of 2019, the Joint Utilities of New York [62] held a stakeholder webinar to provide updates on project solicitation and share challenges and lessons learned in soliciting and implementing

[61] See, for example, New York utility RFPs for NWAs at https://nyrevconnect.com/non-wires-alternatives/ and PG&E's 2019 Request for Offers at https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2019-didf-rfo.page?WT.mc_id=Vanity_rfo-didf&ctx=large-business.

[62] Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., 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.

NWAs. Common solicitation and evaluation challenges include poor proposal development, with insufficient information or unproven technologies, minimal modeled load relief during periods of greatest need, uncertain deal structure for potential developers (e.g., first right of dispatch versus utility ownership), timing of siting and permitting allowances, and simply navigating the new process (e.g., no tried and true templates for NWA contracts).[63]

Consolidated Edison's Brooklyn Queens Demand Management program uses targeted energy efficiency projects and distributed generation—combined heat and power (CHP), fuel cells, and battery energy storage—to provide load relief in specific networks in Brooklyn and Queens. Upwards of 52 MW of load relief have already been achieved, with ~11 MW of additional relief planned by 2021. Energy efficiency projects have focused primarily on lighting, with incentive amounts and installation support varying by customer class.[64] For CHP, the utility offered up to $1,800 per kW, with a cap at $1.5 million per project. For fuel cells, the utility matched New York State Research and Energy Development (NYSERDA) incentives up to $1,000 per kW, with an aggregate project cap of $1 million. This matching program remained active through NYSERDA through the end of 2019. For both CHP and fuel cells, Consolidated Edison identified target zones and years to guide development, and offered an additional 25% incentive bonus on top of $1,000 per kW for projects that alleviated constraints by meeting locational and temporal criteria.[65] For battery energy storage, the utility offered $2,100/kW for selected customers in designated neighborhoods in Brooklyn and Queens whose systems could meet a minimum four-hour consecutive dispatch and who could be in operation by June 1, 2020.[66]

[63] Joint Utilities of New York. 2019. Stakeholder Engagement Webinar DER Sourcing / Non-Wires RFP Process. https://jointutilitiesofny.org/sites/default/files/Joint-Utilities-of-New-York-DER-Sourcing-Stakeholder-Webinar-5.29.19.pdf.
[64] Consolidated Edison. 2019. Non-Wires Solutions. https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-wires/con-edison-non-wires-webinar.pdf.
[65] NYSERDA. 2019. Clean Energy Fund. Stationary Fuel Cell Program. Summary of Revisions. https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt000000CrRMSEA3.
[66] Designated neighborhoods and additional program details available here: https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/brooklyn-and-queens-energy-storage-incentive.

## Rate Structures

The NY PSC, through REV, incorporates locational value into new rate structures in two primary ways: (1) through the VDER tariff and (2) by encouraging utilities to pilot dynamic rates that contain time-based and locational price signals, including a price signal that captures avoidable distribution system costs.[67]

As part of the VDER proceeding (REV Track 2), the NY PSC specified that eligible DERs[68] receive compensation for location-specific attributes they provide when injecting generation into the utility system. This compensation mechanism has been developed using a tariff structure known as the "Value Stack." The Value Stack is calculated based on five categories of utility costs that DERs offset (Figure 17): (1) energy value, (2) capacity value, (3) environmental value, (4) demand reduction value (DRV), and (5) locational system relief value (LSRV).

The energy value that DERs receive is based on the hourly day-ahead location-based marginal prices (LBMPs) from the NYISO energy market, in the zone in which the DER is located. Similarly, the capacity value that DERs receive is based on region-specific clearing prices in the NYISO installed capacity (ICAP) market, with the value allocated to summer afternoons to reflect times of peak demand when DER injections would be most valuable in offsetting future capacity needs. The environmental ("E") value is allocated to all DER generation equally and is based on statewide Renewable Energy Credit prices or the Social Cost of Carbon less the RGGI value,[69] whichever is higher.

The demand reduction (or "Avoided D") value is intended to represent the subtransmission and distribution costs that the utility avoids as a result of the DER. In this way, DERs that qualify for the Value Stack tariff are eligible to receive DRV compensation for their contribution to local system needs. The LSRV adder is available in locations that the utility has identified as having investment needs that can be addressed by DERs. Similar to NWA solicitations, compensation for this additional value is intended to target highly constrained areas which would very likely require upgrades or other new investments in the absence of increased capacity contributions from DERs.

[67] See https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources.

[68] DER projects that qualify for Value Stack are: (1) those that are not eligible for Phase One Net Energy Metering (NEM, although those projects can opt into the Value Stack) and (2) those that have advanced utility meters capable of measuring hourly electricity exports and imports. Phase One NEM-qualifying projects were installed between 3/9/2017 and 1/1/2020, are non-commercial, and fall within the megawatt limits set by the utility. Additionally, projects under 750 kW AC that exclusively serve a host load can choose the Value Stack or Phase One NEM. All other projects under 5 MW are eligible for the Value Stack. For more information, see https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources.

[69] A portion of carbon impacts is already internalized in the markets through the Regional Greenhouse Gas Initiative (RGGI). The environmental value seeks to capture the remaining societal greenhouse gas costs.

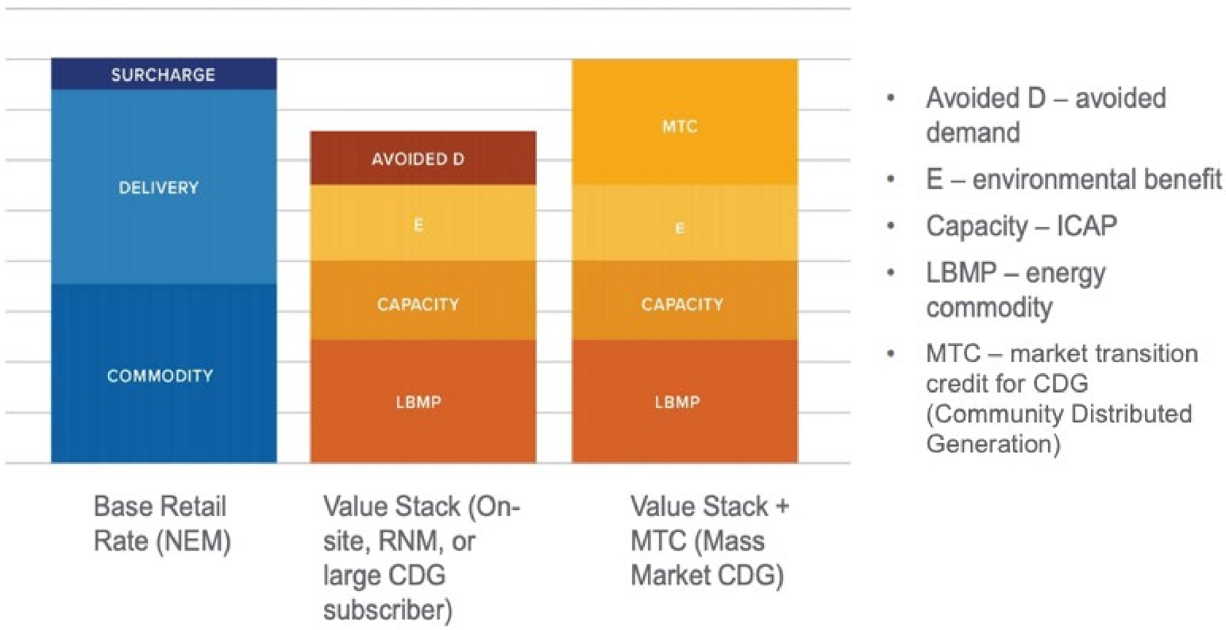



**Figure 17. VDER Phase I Value Stack Compensation**
Source: NYSERDA 2019. *CDG - community distributed generation; RNM - remote net metering*.

**Long Island's Value Stack for Distributed Energy Resources**

The Long Island Power Authority, a state-owned utility, initiated a VDER proceeding and has developed a Value Stack tariff that is similar to such existing tariffs for the state's regulated utilities. There are two important differences (PSEG 2019):

(1) Mass market participants (residential and commercial customers without demand charges) in community distributed generation projects receive volumetric (kWh) credits rather than monetary credits.
(2) Compensation for projects receiving Installed Capacity (ICAP) Alternative 3 is based on grid injections for the top 10 hours of annual peak utility demand, rather than the single top hour.

Each utility files a monthly statement that includes actual monthly ICAP rates, its current DRV and LSRV rates, and the LSRV capacity remaining per substation.[70] Discussion continues on how these rates should be calculated. For example, currently DRV and LSRV rates—both important locational stack components—are determined based on each utility's calculated marginal cost of service for the year. Marginal cost of service methodologies can vary significantly across utilities. Some have argued that variation in what each study includes is part of the driver behind the significant discrepancies in

[70] NYSERDA. The Value Stack. Link to previous monthly filings: https://www.nyserda.ny.gov/All%20Programs/Programs/NY%20Sun/Contractors/Value%20of%20Distributed%20Energy%20Resources.

marginal cost of service values—and the corresponding discrepancies in DRV and LSRV rates. To address this, the PSC is examining the marginal cost of service studies and their relationship to the Value Stack (NY PSC 2019). Utilities, PSC staff, and stakeholders are working to address key challenges and areas of improvement for these studies, as well as interactions between these studies and DER compensation (through the DRV and LSRV components of the Value Stack):

- Greater uniformity of the method and approach in developing the marginal cost of service studies, across New York utilities
- Balance between changing the compensation signal dynamically based on system conditions and changing capacity needs, and a longer-term price signal for DER revenue that reduces uncertainty and makes projects easier to finance
- Balance between an "average" systemwide DRV available in all locations versus a more localized "hotspot" signal that provides greater value in specific areas.

The NY PSC also has directed utilities to explore alternative rate structures that would provide more granular price signals to consumers in REV demonstration projects. The NY PSC identified Smart Home Rates as one promising alternative rate structure and directed utilities to work with NYSERDA to create demonstration projects. In the REV Track 2 order, Smart Home Rates are defined as a combination of "highly granular time-based rates with location-and-time-based compensation for DER, in a manner that is managed automatically to optimize value for the customer and the system" (NY PSC 2016a).

The utilities began drafting proposed pilots in 2017, and some released full implementation plans in 2018. For example, Consolidated Edison and Orange and Rockland utilities worked with consultants and vendors to deploy price-responsive home energy management platforms among targeted residential customers (Consolidated Edison and Orange & Rockland 2019). With Sunverge as their technology partner, these companies trained operators, enrolled customers, and delivered and installed hardware and are monitoring data on implementation effectiveness.

The Smart Home Rate was designed with two opt-in rates that share a common framework reflecting temporal and locational granularity separately for unbundled cost components, including delineation between energy supply and energy capacity and between future marginal, and past embedded, T&D delivery costs. Each rate takes a different structural approach to reflecting capacity costs. Rate A uses a daily demand charge with critical peak event charges; Rate B uses a monthly delivery subscription coupled with critical peak overage charges when consumption exceeds the subscription level. In both cases, critical peak events can be declared at multiple levels, with the utility's distribution system the most granular. These rate components act as locational price signals at the service territory level, or possibly even more locally depending on how each utility implements critical peak events. Through the smart home devices being provided to pilot participants, customers can reduce demand during locally constrained times, and the utility can mitigate its peak load requirements.

As part of the VDER Proceeding, the Commission also began a process to redesign Standby Service and Buyback Service Rates at each of the New York State utilities. Unless otherwise exempted, distribution utility customers that use generation technologies to export power to the electric grid, or reduce their own use of power taken from the grid through onsite generation, are subject to these rates. Standby rates are based on a customer charge to recover customer-related costs, a daily as-used demand charge to recover shared distribution costs, and a contract demand charge to recover local costs that cannot be shared by many customers. As part of this reconsideration of the existing Standby Service and Buyback Service rates, the Commission required each utility to offer these rates, once approved, to all distribution customers as an opt-in demand-based rate option. The rates are designed to be as cost-reflective as possible.

**Hosting Capacity Analysis**

The 2017 DSIP Filing Order, based on the earlier Rev Track 1 and DSIP orders (14-M-0101 and 16-M-0411, respectively), also required utilities to calculate and improve circuit-level hosting capacity data (NY PSC 2017). The Joint Utilities of New York have developed a Hosting Capacity Implementation roadmap (Joint Utilities of New York 2019).

# 6. Utility Case Studies

This chapter presents case studies illustrating different approaches and tools that utilities have used over time to determine the locational value of DERs (Table 11).

**Table 11. Utility Case Studies on the Locational Value of DERs**

| Case Study | DERs | System Level | Year |
|---|---|---|---|
| PG&E Kerman PV Study | Solar PV | D | 1990 |
| PG&E Delta Study | DSM | D | 1991 |
| Nashville Electric Service | DSM (DR, EE), dispatchable standby generation | T | 1996 |
| Orange & Rockland | EE, DR, DG | T&D | 1999 |
| Consolidated Edison Rainey to East 75th | EE, DR, DG | T&D | 1999 |
| BPA Kangley to Echo Lake | EE, DR, DG | T | 2001 |
| NSTAR Marshfield | EE, DR, solar PV | D | 2007 |
| Maine Power Reliability/Boothbay | EE, DR, solar PV, backup generation, storage | T | 2008 |
| BPA I-5 | EE, DR, DG | T | 2009 |
| Mt. Vernon | EE, DR, solar PV, storage | D | 2013 |
| Emera and Central Maine Power | Solar PV, storage | D | 2014 |
| Xcel Energy Minnesota | EE, DR | D | 2017 |
| Michigan utilities | EE, DR | D | 2017–ongoing |
| NV Energy | EE, DR, storage, solar | D | 2019 |
| Portland General Electric Smart Grid Test Bed | DSM (smart thermostats, heat pump water heaters), EV chargers, batteries | D | 2019-ongoing |
| HECO | BTM solutions | D | 2020 |

*DR – demand response; EE – energy efficiency; D - distribution; T - transmission; BTM - behind-the-meter*

## 6.1 PG&E Kerman Photovoltaic Study (1990)

In 1990, PG&E took the lead in the evaluation of small-scale generation and DSM technologies at the distribution voltage level of service. The 500 kW PV project, near Kerman substation in California's Central Valley, was the first major non-wires alternatives study that evaluated benefits from siting PV generation to relieve distribution system constraints and then implemented the distributed generation solution (Shugar et al. 1992). The U.S. Department of Energy's "Solar Time Line" refers to it as the first "distributed power" non-wires solution—the first known instance of a locally targeted distributed generation resource, completed in 1993.[71]

[71] See EERE. The History of Solar. https://www1.eere.energy.gov/solar/pdfs/solar_timeline.pdf.

The Kerman study evaluated a real distribution planning area—with all of its corresponding operating constraints—as opposed to using a simple system-average cost of T&D. By developing detailed area- and time-specific T&D data, PG&E was able to supplement the traditional utility capital evaluation methodology and recognize increased value of PV to the distribution area.

The study estimated the distribution capacity cost savings attained by siting PV generation at several different points in the Kerman distribution planning area. The methodology compared the cost of PV generation to the least-cost alternative source of generation, energy, and local T&D capacity. As with more contemporary studies, the project demonstrated that multiple value streams must be assessed in order to compare resource types.

The methodology did *not* develop a way to find the best location, size, and installation timing for the PV array. The utility made these decisions based on such factors as solar insolation, PV output, and local expansion plans. These criteria were used to choose the specific installation site, where PV had a relatively high T&D avoided cost value.

This extensive study also explored the possibilities for a “Distributed Utility Future” that was under consideration by PG&E at the time and still echoes in the California DRP planning framework in place today.

The Kerman study had several lasting effects. First, at a time when costs for a 500 kW PV system were $6,500/kW to $10,000/kW, it demonstrated that distributed solar could be cost-effective under some high cost scenarios. The study also confirmed that area-specific data are superior to system average costs when determining avoided cost benefits at the local level. Further, the study demonstrated the critical importance of the correlation between peak local loads and the output of targeted DER, a major reason why the Kerman substation was selected. Finally, and most important, the study established the idea that small-scale generation could realize important T&D system cost savings.

## 6.2 PG&E Delta Study (1991)

PG&E’s Delta pilot project and study developed an $18 million energy efficiency program designed to defer distribution capacity upgrades in the utility’s service territory (Orans et al. 1992). Evaluations suggest that this project produced 2.3 MW of peak demand savings (Neme and Grevatt 2015). The objective was to find the least-cost mix of DSM and local T&D capacity over a 20-year planning horizon. Similar to the Kerman study, the Delta study used area- and time-specific T&D capacity costs to evaluate a real distribution planning area. Yet the Delta study distinguished itself by incorporating a variety of DSM programs (predominantly air conditioning measures) into an integrated T&D expansion plan and used a dynamic evaluation technique to construct the least-cost plan.

The project proved that the coincidence of load reductions and the local area peak enabled DSM to provide T&D capacity benefits by using detailed local area- and time-specific avoided costs that reflected local conditions for the evaluation (Orans et al. 1992). The project found that system averages were not appropriate measures of local T&D benefits because they did not reflect geographical variation, the changing value of local T&D capacity from hour to hour, or the changing value of local T&D capacity over a period of years.

The study identified four key questions:

1. What are the magnitude and timing of peak loads in a distribution planning area?
2. How will DSM affect peak loads at both the bulk and local levels?
3. What are the area- and time-specific marginal costs that reflect T&D avoided costs?
4. How will DSM adoption affect the planning area's expansion plan?

To conduct the study, PG&E used its T&D expansion plan to find the optimal delay of the planned distribution upgrade attributable to DSM. System average estimates for the avoided generation and bulk transmission costs were inputs to the model. Local T&D avoided costs were derived contingent on the utility's choice of the most cost-effective DSM programs. Other input data were hourly loads, area-specific energy prices, and forecasted hourly DSM load reductions.

The dynamic model linked the implementation of a sequence of DSM programs and alterations in peak load to produce a sequence of decreasingly cost-effective DSM programs that produced the required hourly benefits. The integrated plan yielded an expected savings of $35 million over the 20-year planning horizon.

Key lessons learned from the Delta study include the following:

- High investment costs do not mean high marginal costs. A screening study to identify areas with high potential for DSM implementation must be more sophisticated than simply selecting areas with high levels of planned investments.
- High load growth is hard to counteract with distributed resources. Conversely, an area with small growth and modest T&D investments is a good candidate for targeted applications of DSM.
- Care should be taken in defining the planning area. The Delta area was redefined two years into the project when a new plan expanded the area and switched loads between substations.

**Locational Value of NWAs Other Than DERs:**
**Philadelphia Electric Company Doe Run Study**

In collaboration with EPRI, in 1994 the Philadelphia Electric Company (PECO) developed a profitability model to assess the expected financial outcomes—and associated financial risk—of a range of potential T&D investments under uncertain load growth (Price et al. 1995). PECO used the model to evaluate three subtransmission capacity expansion options it was considering to address commercial and residential load growth in a historically rural portion of PECO's service territory, the Doe Run distribution planning area. The three alternatives evaluated included a traditional substation solution (a single 90 MVA transformer), a mobile substation option (60 MVA transformer), and a modular substation option (series of 20 MVA transformers).

PECO's analysis was an innovative approach to accounting for uncertainty in load growth, which can dramatically change the realized value of capacity investments. In light of increased competition in the electric utility sector with restructuring in the 1990s, PECO began to explore alternative T&D investment strategies to decrease risk and increase profitability. The objectives of this study were to evaluate the economic viability of two nontraditional alternatives to T&D capacity expansion in the Doe Run distribution planning area, in recognition of the potential net cash flows and profitability benefits relative to the traditional distribution substation solution.

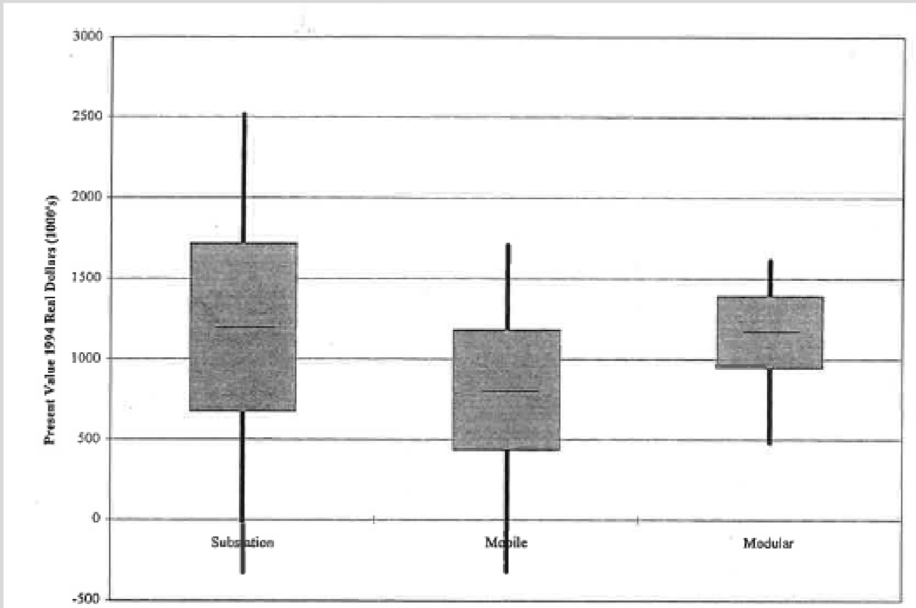
The PECO study modeled load growth uncertainty to create a range of potential load scenarios, then used discounted cash flow analysis to evaluate the economic implications of three potential capacity investment strategies to meet distribution system needs. PECO evaluated the performance of these capacity investment options across a large number of load growth scenarios to develop a statistical representation of anticipated financial outcomes of these alternatives, considering the uncertainty inherent in forecasting load growth.

The profitability model employed three sequential calculation modules:

- The first module randomly generated numerous load growth scenarios, using the area forecast, input load growth uncertainty information, and a Monte Carlo simulation approach.
- The second module used these load growth scenarios to adjust investment timing for each of the potential capacity solutions, based on expected peak load and required lead-time for each investment option.
- The third module calculated cash flows and profitability estimates based on the investments.

The profitability model indicated that the modular substation option was a viable alternative to the traditional substation option, with similar expected present values, but reduced financial risk due to load growth uncertainty. As the figure shows, while the mean profitability (represented by expected present value) of the traditional substation investment and the modular investment were similar at $1.261 million and $1.237 million (in real $1994), respectively, the variance between the two options was quite different. The traditional substation investment had a standard deviation of $522,000, while the modular investment option had a variance of only $221,000, indicating considerably less financial risk from the modular option.

**Locational Value of NWAs Other Than DERs:**
**Philadelphia Electric Company Doe Run Study (cont'd)**




Mean and Variance of Net Cash Flow for Each Alternative Plan After 40 Years

The PECO study highlights three key findings:

- The value of deferring capacity investments associated with the modular option offset the economies of scale associated with the traditional substation investment. Thus, the two options resulted in similar net present values.
- Making incremental, modular (rather than fixed, traditional) capacity investments can reduce the financial risk of T&D expansion by enabling utility planners to more precisely match actual load growth with capacity needs.
- Modular capacity investments reduce short-term cash flow by deferring further capacity investments until they are justified by actual load growth, and therefore limit the negative cash flow associated with traditional capacity investments.

## 6.3 Nashville Electric Service Case Study (1996)

The city of Nashville faced a transmission capacity shortage identified in 1992 (Ball et al. 1996). Local objection to new transmission and concerns about electromagnetic forces had created uncertainty over environmental permitting. Nashville Electric Service (NES), a municipal utility customer of Tennessee Valley Authority (TVA), serves the area.

A joint study by TVA and EPRI evaluated potential NWAs to new transmission to serve the constrained areas, finding that a total DR capacity of 26 MW would be required by 2000 to effectively defer the transmission investment. The study used a methodology adopted from the PG&E Delta Project to develop a local integrated plan that could maintain reliable service without expanding the transmission system within the city. The study was designed to screen NWAs to the identified traditional transmission solution and assess reliability and expected unserved energy of alternative approaches.

In particular, the study's objectives were to:

- Provide a high-level screen of alternative expansion options, such as DSM measures (including direct load control or curtailment) and dispatchable standby generation systems.
- Perform an engineering analysis of the NES expansion plan in which cost and reliability trade-offs are evaluated, essentially creating a planning option to defer transmission expansion by accepting increased levels of expected unserved energy.
- Perform an engineering analysis on suitable alternatives to the existing expansion plan to evaluate operational impacts and ensure comparable reliability levels.
- Use the study and additional considerations to recommend preferred expansion options.

Compared to other NWA assessments done at that time, the NES study included significant engineering assessment of alternatives and included consideration of expected unserved energy to compare plans with different levels of reliability. This allowed a novel cost-versus-reliability trade-off. Typically, NWA studies had assumed that the DER must deliver a comparable level of reliability and were compared based on lifecycle cost to ratepayers.

In addition to a local integrated planning approach that evaluated the potential and cost-effectiveness of targeted DERs to avoid planned transmission upgrades, the study evaluated the hourly load flow for the area and four primary contingencies to estimate the expected unserved energy of alternative plans.

Like other studies of transmission expansion to serve growing U.S. metropolitan areas, this study found that a significant amount of DSM (DR or EE measures) or dispatchable standby generation would be needed to maintain historical levels of reliability. Furthermore, the relative cost of the new transmission compared to the additional capacity that it provided was relatively low: \$7.03/kW-year. Therefore, the additional value of local capacity in avoiding transmission (\$7.03/kW-year) was relatively low compared to the avoidance of additional bulk system and generation capacity (>\$50/kW-year).

A unique aspect of this study was to assess the expected unserved energy of a "do-nothing" scenario where the existing system would serve the forecasted load growth. This approach demonstrated rapidly increasing customer outage costs that became clearly unacceptable within a few years. The utility considered the projected maximum loading and annual cost to customers from outages (expected unserved energy) in the do-nothing case relative to a total project cost of approximately \$12.8 million (Figure 18).

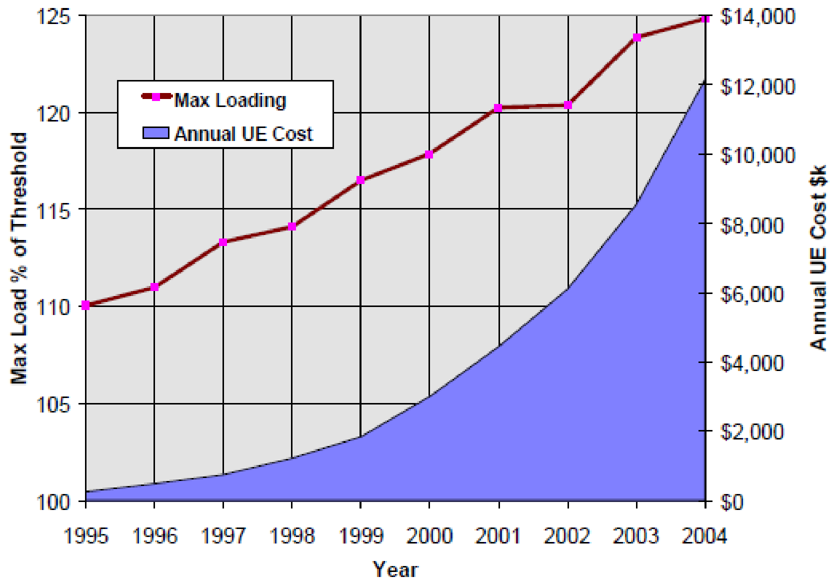



**Figure 18. Maximum Loading and Annual Unserved Energy Costs Under a Do-nothing Scenario**

## 6.4 Orange & Rockland Western Division Load Pocket (1999)

Orange and Rockland Utilities' (O&R) Western Division Load Pocket study evaluated the economic potential to avoid T&D system upgrades (Horii et al. 1999). It was the first assessment completed in response to New York's requirement to evaluate distribution alternatives as part of industry restructuring plans signed at the end of 1997 and early 1998 (NY PSC 1997). Under the restructuring agreement, utilities were required to evaluate all distribution capital projects over a certain cost ($2 million for O&R) for NWAs.

The study compared NWAs to the utility's preferred option of constructing the Middletown Tap (to NYPA's 345 kV transmission system) and building or upgrading facilities to 138 kV from the tap to serve the area.

The Western Division Load Pocket analysis used the present worth method to estimate the ratepayer value of deferring capital expenditures by reducing load in time to defer the planned upgrades. The study used an assessment of the maximum penetration of energy efficiency and other DERs to meet peak load and address the growth driving the projected overloads.

The work led to development of two economic tools for screening NWAs for future projects. The first was a high-level screening tool that evaluated four key criteria:

- *Project applicability:* The nature of the problem and whether DER can solve it
- *Project timeline:* Whether there is time to implement a targeted DER program in the area
- *Project cost:* The potential value for avoiding the investment
- *Maximum incentive levels:* The marginal avoided cost from providing local value ($/kW)

A second, more detailed tool evaluated the potential and cost-effectiveness of targeted DERs for the distribution area. The cost-effectiveness assessment was based on the New York PSC and NYSERDA approach for DER cost-effectiveness, the Standard Practice Manual, with a focus on the TRC test. Unlike other approaches at the time, the tool included the location-specific value of distribution capacity, rather than an adopted system average value.

The study found that DERs—in particular energy efficiency—were cost-effective. However, the required peak load reduction was significantly greater than O&R's energy efficiency potential. Consequently, the O&R study concluded that the proposed Middletown Tap Project delivered the best combination of price and reliability improvements among the expansion options considered, and the NWA solution was not pursued.

## 6.5 Consolidated Edison Rainey to East 75th Street, New York City (1999)

Consolidated Edison's local integrated resource study evaluated the cost-effectiveness of avoiding an upgrade of their network in Manhattan using targeted energy efficiency, demand response, and distributed generation (E3 2002). The traditional project envisioned upgrading five 138 kV circuits from the Rainey 345 kV substation that crossed the East River to serve Manhattan. The need was triggered when higher than projected load growth was observed in Manhattan, due to mass installation of window air conditioning in some neighborhoods as economic conditions improved, at the same time that some aging utility equipment was due to be retired.

The O&R evaluation tools built for the Western Division Load Pocket evaluation were adapted for Consolidated Edison (O&R's parent company) for the study. These tools provided the screening and cost-effective potential of DERs to defer the planned T&D upgrades.

The DER potential estimate was completed using a census of customers in the area. Analysts calculated whether targeted energy efficiency, demand response, and in-area generation could provide sufficient peak load reduction. Cost-effectiveness was assessed using energy and system capacity forecasts and the Standard Practice Manual definition of cost-effectiveness tests. The potential study highlighted the critical role of interruptible programs and distributed generation to provide sufficient load reduction.

An innovative reliability evaluation tool was developed to assess the combined reliability of the resulting distribution system and distributed generation. Most distribution planning studies use an N-1 reliability approach and do not calculate the actual probability of an outage. For the Manhattan networks, Consolidated Edison planned to achieve an N-2 reliability standard. [72]

[72] *N-1* refers to a reliability standard which is based on the ability of the electricity system to withstand the temporary loss of a single, critical power component (or section of transmission line) due to, for example, a severe weather event. Planning to an *N-2* standard is more stringent and refers to a system that can withstand the temporary loss of two critical components without loss of power for customers.

In the study, analysts used information collected by the utility on the probability of equipment failure and required restoration time to estimate the reliability level of the network with different targeted DER plans. Also evaluated was the additional load serving capability provided by DERs when operated in conjunction with the T&D system. This approach allows the T&D planner to target a specific reliability level (e.g., 99.999%) while accounting for differing reliability levels of various DER options.

Figure 19 shows the results of a combined distributed generation and T&D system reliability assessment. The figure shows that the available capacity in the area is greater than the load for three scenarios: (1) no upgrades (magenta dashed line), (2) DERs added to the existing system (solid blue line), and (3) the proposed traditional upgrade (green dashed line). At load levels below about 650 MW, the probability of meeting load was greater than 99.99% in all scenarios. However, as peak load grows, DER can extend load levels that can be served at this level of reliability to about 680 MW. The planned upgrade pushes the reliably served load level above 720 MW.

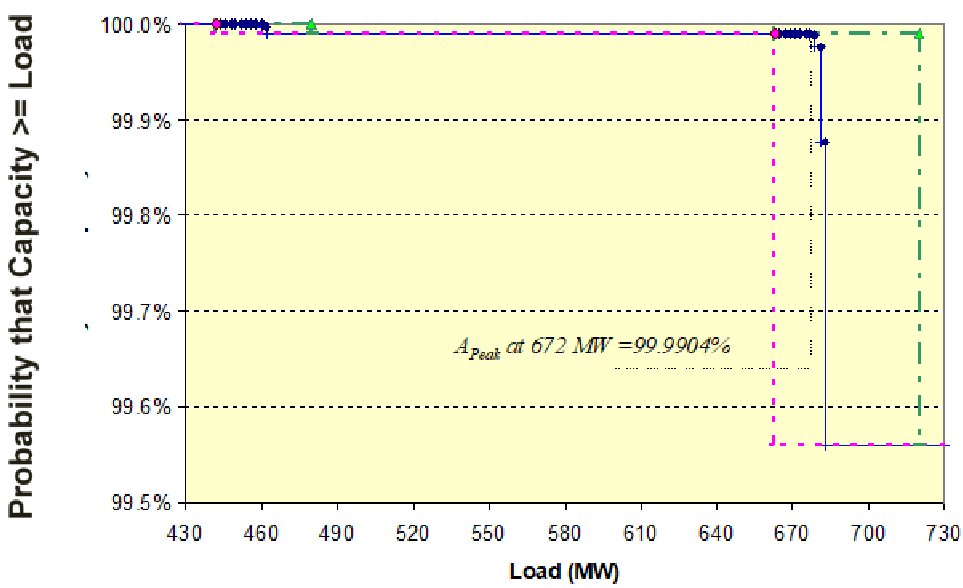



**Figure 19. Availability to Meet a Load for the Combined Distributed Generation (DG) and T&D System**

Constraints for serving loads in Manhattan included:

- *Logistical*: Whether enough distributed generation could be sited
- *Environmental:* Whether Consolidated Edison could secure air permits for new combustion-based generation such as turbines or engines

For these reasons, the study recommended that Consolidated Edison build planned upgrades to reliably serve the rapidly increasing loads in these Manhattan networks.

## 6.6 BPA Kangley to Echo Lake Transmission to Seattle (2001)

The Bonneville Power Administration (BPA) manages the region's transmission and large hydroelectricity facilities and delivers power to local municipal customers, rural electric cooperatives, public utility districts, and a few direct service end-use customers. With growth in the region, the federal power marketing agency faced a number of transmission projects and refined its transmission planning process to identify projects that could potentially be deferred by targeted DERs. In 2001, BPA convened a Non-Wires Solutions Round Table to review and support its assessment of alternatives to new transmission projects (E3 et. al. 2002).

Assessments of cost-effectiveness and potential for customer-sited DERs as NWAs for BPA transmission required a broad collaborative process that included regional and state partners and electric utilities, who ultimately would deliver DER programs to end-use customers. In addition, the nature of the transmission network required a systemwide assessment of the delivered capacity relief from load management.

BPA has completed numerous NWA assessments since the early 2000s. As one example, the Kangley to Echo Lake project—a proposed transmission line connecting these locations and ending at the Echo Lake Substation—faced public resistance because a section of the line was to be built through Seattle's Cedar River Municipal Watershed, a pristine area and a source of drinking water for the city. BPA commissioned a study to evaluate NWAs to the project and provide information to stakeholders about trade-offs related to its construction. Consistent with the goals of BPA's Non-Wires Solutions Round Table, the study team worked closely with a stakeholder group to characterize the need for the transmission line and potential for DERs to reduce peak loads sufficiently to defer this need, and then to evaluate the relative economics of DERs versus the new transmission line.

Among the innovations of this project was working closely with BPA transmission planners and engineers to characterize the impact that load reductions in various locations in the Puget Sound area would have at the capacity-constrained point of the transmission system. Because of the network configuration of the transmission, a 100 MW load reduction in Seattle, for example, would reduce the peak load at the constraint only by about 42 MW. Figure 20 maps load reductions by location across the study area to the achieved peak load relief at the constraint.

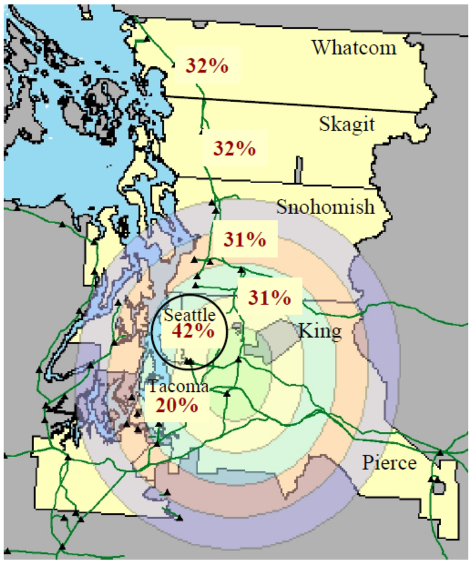



**Figure 20. Map of the Kangley-Echo Lake Study Area and Load-flow Distribution Factors**

For transparency, analysis of NWAs was completed using MS Excel, so results could be readily shared with members of the BPA Non-Wires Solutions Round Table.

The economic analysis of this project demonstrated that additional locational value for local resources based on deferring the line were extremely low. Notwithstanding the high-profile nature of the new line, the costs were not high relative to the amount of additional load that could be served in the area. A three-year deferral, for example, was found to have a value of approximately $5.70/kW-year per kW reduction at the constraint. This translates to less than half that amount per kW of load relief given load flow distribution factors. This low value was due to the cost of the line and the significant reduction in energy losses that building the line would provide for the region's transmission system.

Ultimately, BPA built the Kangley-Echo Lake line to improve the reliability of the transmission system in the Puget Sound area, rather than implementing NWAs. BPA worked closely with stakeholders to develop a plan to mitigate some of the impacts.

## 6.7 NSTAR Marshfield Pilot (2007)

The Marshfield Pilot for NWA, facilitated by the Massachusetts Technology Collaborative,[73] focused on potential peak load reductions in the town of Marshfield through customer-sited DERs (Rocky Mountain Institute et al. 2007). The goals of the project were to:

- Develop a proof-of-concept approach for local integrated resource planning in NSTAR's service territory.
- Achieve at least 3 MW of load reduction over two years using energy efficiency, demand response, and solar PV.

[73] Now known as the Massachusetts Clean Energy Center.

- Explore marketing and customer adoption synergies between rooftop solar, energy efficiency, and demand response.

The project estimated the potential load reduction, cost, and opportunity scale of different technologies and engaged community members to better understand potential participation and interest in the program. A novel feature was bundling energy efficiency, solar, and direct load control initiatives. This was of particular interest in order to offset the higher cost of rooftop solar with lower cost DERs.

Going beyond a desk study on the economics of DERs compared to the required capacity upgrades identified by NSTAR's distribution planning staff, the Massachusetts Technology Collaborative and NSTAR solicited program participation and provided financial incentives to encourage targeted deployment of DERs for homes and businesses to defer planned distribution investments (DeVito 2010). The pilot program was available to all local residents but included additional efforts to reach property owners on congested circuits, given the larger potential value of deploying DER in these areas (Fuller et. al. 2010).

Among the program's successful outreach and engagement activities were using targeted direct mail promoting special offers and selecting 12 local "ambassadors" who led by example by installing the measures at their own homes. The project's direct engagement approach generated impressive participation in 2008 and 2009, reducing peak load by 1.2 MW and energy consumption by 3% (Fuller et. al. 2010).[74]

## 6.8 Boothbay NTA Pilot (2008–2017)

Central Maine Power (CMP) and Public Service of New Hampshire filed a petition at the Maine PUC for the Maine Power Reliability Program in July 2008 (CMP PSNH 2008). The utilities proposed to construct about 350 miles of transmission and associated infrastructure, nearly all in Maine, at an estimated total project cost of $1.35 billion. After extensive litigation on a wide range of topics, the parties in the proceeding reached a stipulation filed in June 2010 (CMP et al. 2010). This stipulation, and its approval by the Maine PUC, allowed Central Maine Power to begin construction of the bulk of the proposed project.

The stipulation did not include building the proposed "Mid-Coast Spur," a 23-mile 115 kV transmission line. The parties agreed to pilot non-transmission alternatives (NTAs) for this portion of the proposed project with the goal of maintaining reliability at lower cost. The parties also agreed to designate GridSolar, LLC, as the "Smart Grid Energy Services Operator" for the pilot and, more generally, within CMP's territory. The Maine PUC opened a new proceeding (Docket 2011-00138) to investigate the proposed NTA pilots. CMP analysis indicated that between 39 and 45 MW of load reduction, relative to the forecast, would be required to keep loads below critical levels and avoid the need for any transmission reinforcement.

[74]Marshfield Energy Challenge, http://marshfieldenergy.org/marshfield-energy-challenge/.

After investigation and settlement discussions among the parties, GridSolar, the Office of the Public Advocate, Conservation Law Foundation, Environment Northeast, and Efficiency Maine Trust filed a stipulation for a smaller NTA as an initial pilot in the Boothbay area, along with some transmission improvements (GridSolar et al. 2012). The proposed Boothbay NTA, to be developed and operated by GridSolar, would target a reliable reduction of 2 MW of load designed to avoid rebuilding the 34.5 kV line from Newcastle to Boothbay Harbor. The Maine PUC approved this stipulation in April 2012 (Maine PUC 2012).

The NTA pilot was designed to last for three years, with the option to extend for 10 years. This structure allowed time to implement the original project if the NTA option did not work as intended, as well as an extension if the transmission investment could be further deferred.

The expected cost of the transmission line was $18 million. After accounting for the cost of capital and amortization, deferring this investment was estimated to save Maine ratepayers about $3 million per year (Maine PUC 2012). If NTA resources (such as long-lived energy efficiency measures) resulted in deferral after the end of the pilot, ratepayers would benefit further.

The Boothbay NTA pilot was established to answer a set of explicit questions about NTAs:

> "a. Whether and what type of NTAs can be acquired at reasonable cost to meet grid reliability requirements;
> b. Whether and the best means by which the new Advanced Metering systems being deployed by CMP can provide the information and communications requirements to support NTA solutions to grid reliability issues;
> c. Whether NTAs are capable of responding in the manner necessary to provide grid reliability service to CMP;
> d. Whether the results of this Pilot Project can be scaled to meet the grid reliability requirements of other regions of the CMP and BHE networks in Maine" (Maine PUC 2012).

The stipulation required acquisition of a wide range of resources. Of the 2 MW of target total capacity, at least 250 kW had to come from each of four categories: "energy efficiency, demand response, renewable distributed generation (at least half of which shall be photovoltaic solar energy), and non-renewable distributed generation (with preference given to resources with no net emissions of greenhouse gases)" (Maine PUC 2012).

GridSolar conducted two rounds of procurement through requests for proposals in 2012 and 2013 and acquired 1,805 kW of nameplate capacity[75] from 41 sites and 11 vendors (GridSolar 2017). Table 12 summarizes the resources.

[75] The PUC reduced the target procurement below 2 MW to account for lower load growth than expected.

**Table 12. Boothbay Pilot Resource Summary (GridSolar 2017)**

| Resource Type | Nameplate (kW) | Capacity (kW) | Average Capacity Price ($/kW/month of capacity) | Cost ($) |
|---|---|---|---|---|
| Efficiency | 244 | 256 | 27.47 | 232,893 |
| Solar PV | 308 | 214 | 49.78 | 364,439 |
| Backup Generator | 500 | 455 | 17.42 | 585,049 |
| Demand Response | 23 | 23 | 110.00 | 112,269 |
| Energy Storage | 500 | 500 | 168.70 | 3,016,974 |
| Peak Load Shifting | 230 | 230 | 110.00 | 860,198 |
| **Total** | **1,805** | **1,679** | **73.76** | **5,171,821** |

GridSolar developed the Boothbay NTA portfolio of resources between July 2013 and May 2015. At the same time, the projected load growth triggering a reliability solution did not occur, and CMP did not need to call on the NTA resources to meet a reliability need. Nonetheless, GridSolar established an Operations Center to respond to notifications from CMP to reduce load and tested the dispatch of its NTA resources. The resources generally responded to the dispatch request as expected.

In 2016, while acknowledging the lower load forecast, the Maine PUC agreed with GridSolar and other parties to continue the pilot for one additional year to gather more information on resource performance (Maine PUC 2018). During that year, GridSolar dispatched the NTA portfolio as though critical load levels were reached in order to simulate expected operating conditions and communication signals from CMP to GridSolar and then to resources. Under these protocols, NTA resources were dispatched 43 times on 21 days, for a total of 257.15 hours (GridSolar 2017). The Boothbay pilot ended in late 2017.

The total cost of the four-year pilot was $5.8 million. Of this amount, CMP ratepayers paid $1.75 million. The remaining costs were allocated across New England using the Pool Transmission Facilities process.[76] In comparison, the overnight cost of the avoided transmission project was initially estimated at approximately $18 million (Maine PUC 2012), and Grid Solar cites a CMP estimate of lifetime carrying costs (in nominal terms) for the transmission investment of over $75 million, assuming a 45-year life for the transmission solution (GridSolar 2017).

The NTA pilot likely avoided rebuilding a transmission line that would have turned out to be unnecessary.

GridSolar identified a number of lessons learned from the Boothbay pilot for future NTA implementation. The Maine PUC echoed those lessons in its order concluding the pilot (Maine PUC 2018):

[76] ISO New England. PTF Catalog. https://www.iso-ne.com/system-planning/transmission-planning/ptf/.

- Procurement processes for NTA resources should include a reserve margin for active resources to account for the risk they could be unavailable when dispatched.
- Active demand resources such as backup generation, active demand response, and microgrids can be challenging to acquire, at least in the seasonal, relatively narrow economy of the Boothbay region.
- Load profiles may shift during (or because of) the NTA, and flexibility in active demand resources to address these shifting profiles should be incorporated in NTA plans.
- The limited duration of the project may have made it more difficult to acquire resources, made those resources more expensive, and made the pilot less suitable for providing general lessons.
- The battery resource was among the most effective NTA resources but was also the most expensive (although battery costs are falling).
- The role of advanced metering systems was not evaluated in the pilot, in part due to disputes between GridSolar and CMP regarding access to data.
- Competitive solicitation of passive energy efficiency may not have been necessary or cost-effective, as Efficiency Maine Trust ended up providing all the efficiency resources.
- Further analytical tools may be required to address the reliability of NTA solutions and compare them with wires solutions, as well as to determine whether the Boothbay results and experience can be scaled and applied to other locations.

## 6.9 Bonneville Power Administration I-5 Reinforcement Project (2009)

BPA proposed the Interstate 5 (I-5) corridor reinforcement project in 2009 to add a 500 kV line to increase the north-south transmission capability from southern Washington state into Oregon near the I-5 corridor (E3 2011b). Given the environmental and siting challenges of a project in a highly populated area, several possible routes were studied to expand north-south transfer capability. Local opposition, which was already significant along each of the potential routes selected, increased when stakeholders realized the additional transmission capacity would serve exports from the Pacific Northwest to California.

The objectives of the I-5 study were to identify cost-effective NWAs to the transmission project and defer the need for building the proposed new transmission. The approach was similar to other BPA NWA assessments (e.g., Kangley-Echo Lake). The study first evaluated load growth in the local areas impacting the transmission constraint, then identified cost-effective NWAs, including energy efficiency, demand response, and distributed generation, that could reduce the load affecting the constraint and thereby reduce the need for new transmission.

As with other transmission alternative projects, this study found that a significant amount of capacity would be required to defer the project. In this case, an infeasible amount of customer-sited resources would have been required relative to the amount of time before overloads would occur. This is partly due to the interstate transfer function of the transmission system. While local load for Portland General Electric would be served by the line, a significant portion of the line’s transmission capability would serve destinations south of Portland.

As a result, BPA expanded the range of options beyond customer-sited DERs to include contracting with generation along the north-south corridor to change their dispatch. By decreasing generation north of the constraint and increasing generation south of it, the existing transmission system could support significant additional north-south transfers without a new line.

The two-year pilot program begun in 2017 as a result of the study included both DSM to reduce load (through DR and targeted EE) and bilateral contracting with DG customers to balance generation on either side of the capacity constraint (Potter et al. 2018). The 46 MW DR program required customers to reduce demand for four hours at a time on the top 10 peak summer days, while the bilateral contracting addressed the transmission constraint by providing additional generation south of the constraint and reduced generation north of this point to balance power flows on the transmission line.

Because the study indicated that competitive solicitation from local generation could alleviate the transmission project, the value of relieving the constraint was not published. Providing this value may have influenced the few available generators at the necessary locations in their redispatch bids. BPA solicited what were effectively capacity call options to redispatch generation in times of peak load so the north-south load could be served without the new 500 kV transmission project. BPA decided not to build the project (Figure 21).

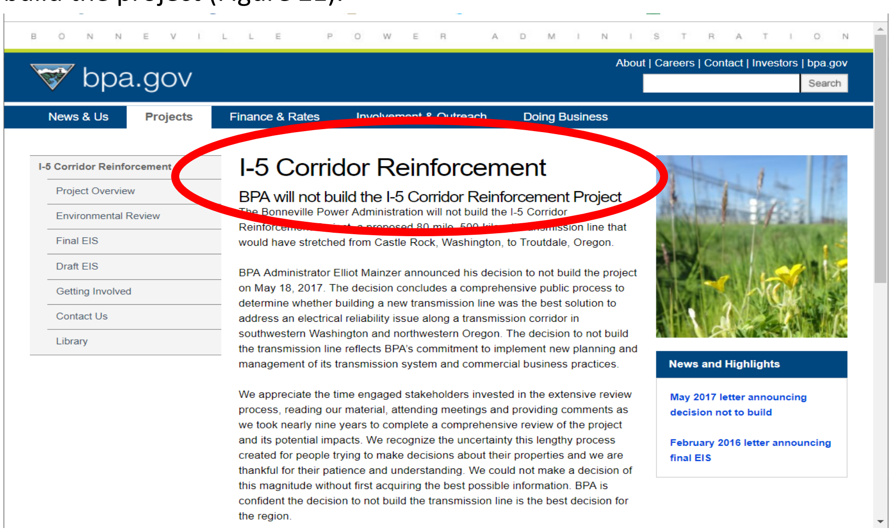



**Figure 21. BPA website announcing cancellation of the I-5 Corridor Reinforcement project**

## 6.10 Mt. Vernon Substation Case Study (2013)

Pepco, the electric utility serving the District of Columbia, identified the potential need for a new substation in the Mt. Vernon area in 2013 due to load growth. In its 2013 Annual Consolidated Report (ACR), Pepco described a need created by the "rapidly developing area in and around the Mt. Vernon Triangle" (Pepco 2013).[77] In 2017, Pepco filed a Notice of Construction (NOC) for an extensive

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[77] In its first ACR analysis, Pepco projected the new substation would be required for service in the summer of 2020 in order to

transmission upgrade project, the Capital Grid project, that would link to a new Mt. Vernon Substation (Figure 22). The NOC indicated that the Capital Grid project was driven by the need to address aging infrastructure and the additional reliability that could be achieved by a looped topology to transmission in the District.

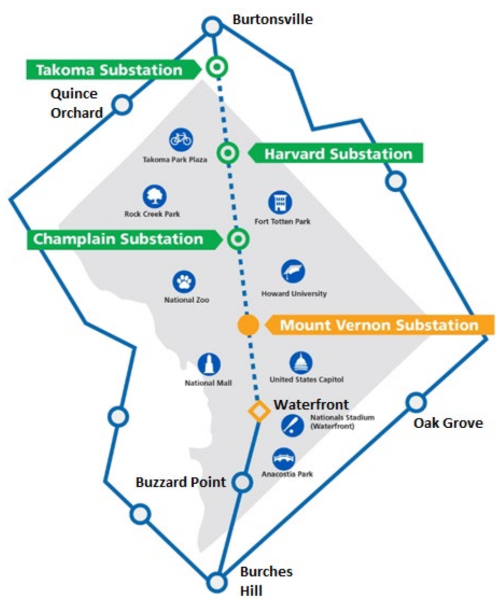


**Figure 22. Pepco's Proposed Capital Grid Project: Three Upgraded Substations (green), a New Transmission Line (dashed line), and a New Mt. Vernon Substation (Synapse 2017)**

Pepco's NOC for the Capital Grid project excluded the Mt. Vernon substation. Pepco informed the District of Columbia Public Service Commission that the NOC that would include the Mt. Vernon substation would be filed in early 2018. The utility stated:

> Pepco will file the second NOC separately so that it can continue to assess the impact of DER on the timing of the construction of the new Mt. Vernon Substation… The impact of DER, demand side management (DSM) programs and energy efficiency (EE) programs must be analyzed, as they can offset a portion of future load growth, possibly delaying the need for future capacity expansion… It is possible that the predicted reductions from DER, DSM and EE could delay the need of future capacity additions, such as additional transformers to the substations, or delay the in-service date by which a substation is needed solely to accommodate load growth" (Pepco 2017).

relieve the Southwest Low Voltage AC Network Group (SW LVAC Network). Subsequent ACRs refined the load forecast, each showing how a substation solution would both address the capacity limits on the SW LVAC Network and assist with other, less pressing issues on nearby substations and networks. Changes in load forecasts, and incorporation of DERs in the ACR load forecasts starting in 2017, shifted back the date of need. Pepco's analysis presented in its 2019 ACR indicates that load will exceed the SW LVAC Network's rated capacity of 50 MVA in summer 2023 (Pepco 2019).

The District of Columbia's Department of Energy and Environment (DOEE) and its consultant examined the potential for targeted DER deployments to advance the District's broader energy objectives, provide energy and capacity, and provide additional value by deferring or avoiding the cost of the proposed Mt. Vernon substation. DOEE sought to quantify the locational value of DERs by calculating the net value of a DER-based deferral or avoidance of this $143 million project,[78] while establishing a framework for analysis of future NWAs. DOEE filed the resulting report in January 2018 in the MEDSIS proceeding (see Section 5.2) as an example of NWA analysis within the MEDSIS framework.

The analysis found that a portfolio with 3.5 MW of efficiency, 5 MW of demand response, 1 MW of solar PV, and 5 MW of battery storage would be able to defer the substation past the end of Pepco's load forecast period. The net value of deferral to 2030 was estimated to be $41.2 million, while complete avoidance could be worth over $200 million in present value.

The Commission reviewed Pepco's Mt. Vernon substation (and broader Capital Grid) proposal under the NOC process in DC law (15 DCMR § 2111.1). Under this statute, the Commission evaluates the proposal for "reasonableness, safety, and need." The DOEE analysis includes assessing the need for the substation (which primarily relates to load forecasting) and provides information on whether it is reasonable to take DER-based actions to defer or avoid the proposed substation project.

Pepco identified several aspects of DOEE's analysis that did not align with the utility's approach to distribution planning and were outside the scope of what it is allowed to do under current Commission orders related to utility restructuring in the District. In response, DOEE encouraged the Commission to consider novel approaches to ownership and control of DERs to enable utility customer savings. For example, DOEE proposed using some proceeds from the Exelon-Pepco merger to pursue a DER-based NWA in the Mt. Vernon neighborhood.

In December 2019, the Commission approved Pepco's request to build the Mt. Vernon substation, finding that the local area would otherwise be at risk for overload or operation at high loading and degrade the reliability of the distribution system (DC PSC 2019).

## 6.11 Emera and Central Maine Power 2014 NTA Analysis (2014)

In 2013, the Maine Legislature passed a wide-ranging energy bill that required consideration of NTAs in the approval requirements for transmission projects by an independent third party that is either the PUC itself or a contractor to the PUC (Maine 2013). This statutory provision has been used in three proceedings to date, all beginning in 2014.

In Docket 2014-00048, Emera proposed a transmission line in northern Maine, near the New Brunswick border. In Dockets 2014-00049 and -00050, CMP proposed transmission lines in the Lakes Region and Waterville-Winslow Region, respectively. The Maine PUC required utilities expecting to file for approval

[78] Estimated cost of the project has varied throughout its history; this value is the most recent (Pepco 2019b).

of a transmission line to announce that intention in a pre-filing that allows sufficient time for the Commission's consultant to conduct an NTA analysis.

While the consultant's NTA analysis on Emera's proposed northern Maine transmission project was not made publicly available, the PUC's final order in the docket discusses it briefly (Maine PUC 2015a) and summarizes the cost of each option. The NTA that the consultant identified was less expensive than Emera's proposed project but more expensive than a substation upgrade identified in the proceeding as an alternative to the transmission project. The PUC ordered the utility to pursue the lowest-cost option (which required action in New Brunswick, rather than Maine), rejected Emera's proposed solution, and opened a new proceeding to consider connections between northern Maine and ISO New England.
An NTA analysis for the Lakes Region Transmission Project by another consultant considered six Alternative Resource Configurations (ARCs) (La Capra 2015a):

- "ARC 1: Natural gas-fueled combustion turbine peaking units in increments of 5 MW
- ARC 2: Oil-fueled combustion turbine peaking units in increments of 5 MW
- ARC 3: Natural gas-fueled combined cycle units in increments of 5 MW
- ARC 4: Biomass units in increments of 10 MW
- ARC 5: Incremental energy efficiency ("EE") and natural gas-fueled combustion turbine peaking units in increments of 5 MW (the energy efficiency capacity grows annually, totaling approximately 7 MW by 2030)
- ARC 6: Incremental energy efficiency and natural gas-fueled combined cycle units in increments of 5 MW"

The consultant for the Lakes Region project evaluated the value of NTAs by comparing the net present value of costs to utility customers of the proposed transmission solution and each of the alternatives. Calculations included total cost and cost to Maine utility customers, after socialization of costs for the transmission project to the rest of ISO New England.

The net present value of the transmission solution was $69.6 million, falling to $39.9 million after Pool Transmission Facilities costs are shared across the region. While ARC 6 (incremental energy efficiency and small natural gas turbines) was less expensive on the basis of total cost ($60.7 million), these resources could not be shared across the region and would be more expensive for Maine ratepayers (La Capra 2015a). CMP has not yet made its full application to build the Lakes Region Transmission Project.

The same consultant completed a similar NTA analysis with a similar set of ARCs for CMP's proposed Waterville-Winslow Project (La Capra 2015b). The composition of ARC 6 was changed to solar PV capacity with battery backup, instead of energy efficiency and natural gas turbines. The consultant compared the NPV of ratepayer costs of the transmission solution ($37.7 million total cost, of which Maine ratepayers would pay $15.6 million) and ARCs 1 through 5. The NPV of the costs of the ARCs ranged between $53.1 million (ARC 3) and $241.7 million (ARC 4) (La Capra 2015b).

ARC 6 was not evaluated on the same basis. The proposal for the transmission project was driven by the utility's assessment that it needed to sustain unexpected loss of transmission assets for the duration of maintenance work. ARC 6 required sufficient solar and battery capacity to provide sustained power. The analysis determined this option to be very expensive.

GridSolar filed an alternative NTA analysis in the proceeding, challenging assumptions regarding performance of other assets in CMP's analysis of transmission need (GridSolar 2015). Using GridSolar's assumptions, the required NTA could be substantially smaller, especially if CMP were able to target its maintenance work to times other than at peak load.

The Maine PUC approved a stipulation among some parties approving the transmission project (Maine PUC 2015b). In 2019, CMP filed notice that the expected cost of the project during construction had been revised upward by about 37% (CMP 2019). Nevertheless, this cost still remains below the consultant's estimated cost of any of the NTAs analyzed. CMP anticipated the project would be completed in May 2020.

## 6.12 Michigan utilities (2017–ongoing)[79]

Consumers Energy developed the Energy Savers Club program (2017–2018) to test the efficacy of using NWAs to reduce load at the Swartz Creek substation. The substation was experiencing high peak loadings due to increases in load growth, and there was sufficient time to explore deferring the substation upgrade with these options.

To reduce load requirements below 80% of maximum summer capacity (i.e., to reduce peak load by 1.4 MW by 2018)—and potentially defer a $1.1 million infrastructure investment, saving customers money—the utility turned to ramping up participation in their energy efficiency and demand response programs in the area served by the distribution substation.

The Energy Savers Club was a uniquely branded marketing campaign to connect commercial and industrial (C&I) customers to existing energy efficiency programs, and residential customers to existing energy efficiency and demand response (AC Peak Cycling and TOU) programs. The largest savings came from commercial lighting efficiency measures and residential demand response. The pilot tested the role that energy efficiency and demand response programs can play—as potential lower-cost solutions—in managing load and deferring distribution capacity-related investments when targeting specific capacity-constrained geographies.

In 2019, Consumers Energy launched another NWA pilot, at Four Mile substation. Designed to run through 2021, the goal is to defer $2.5 to $3 million in future capital spending by reducing peak load by 0.5 MW. NWAs will include geotargeted energy efficiency and demand response programs for residential and C&I customers.

Another Michigan utility, DTE Electric, used geographically targeted energy efficiency and demand response measures (e.g., interruptible air-conditioning switches) for residential and C&I customers to field test NWAs for load relief for the Hancock Substation. The project began in 2018. The utility projected strong load growth to push the substation 10 MVA over its designed rating in the next three

[79] See August 14 and November 19, 2019, workshop presentations on the [Michigan PSC Electric Distribution Planning webpage](#).

to five years. The utility also is testing storage at a solar site, for electric vehicle fast-charging and mobile applications to reduce infrastructure investments. The utility is exploring several additional sites for NWA pilots beginning in 2020, including energy efficiency, demand response, and storage.

Indiana Michigan Power is considering NWA pilots at several candidate substations as well, including its Vicksburg substation. The substations are on radial circuits, serve high customer densities, are located at the fringe of the utility's service area, and are experiencing reliability issues. The utility is considering battery, microgrid, and DSM solutions.

## 6.13 Xcel Energy – Central Minnesota (2019–2020)

Xcel Energy and the Center for Energy and the Environment (CEE) began an NWA pilot focused on existing energy efficiency and demand response programs with targeted customer outreach in June 2019 in the cities of Sartell and Sauk Rapids in central Minnesota. The estimated capacity need for the area was 1.5 MVA in 2020 (Xcel Energy 2019). The pilot sought to defer or avoid a new transformer and feeder reconfiguration. Field activities were completed in summer 2020.

Among the objectives of the pilot was to offset projected peak demand growth in the target location for year-by-year reduction in load of 500 kW. Another objective was to test geotargeting demand response as a distribution system resource to assist with local grid management. During the research stage, Xcel Energy and CEE found that more than 4,000 residents and businesses in the pilot area already were participating in the utility's demand response programs.

The pilot achieved its goals for both energy efficiency and demand response to meet the stated project needs. At the same time, the utility updated its planning forecast during the pilot, mitigating the need for a distribution upgrade. In addition, a large community solar project was connected in the target area during the pilot period. That significantly changed the load in the local area and provided opportunities to redeploy demand response to mitigate the need for distribution system upgrades to accommodate the solar project.

CEE used community-based marketing strategies to increase participation in efficiency programs in these cities. Table 13 describes these strategies by market sector.

**Table 13. Community-Based Marketing Strategies for the Central Minnesota NWA Pilot**

| Residential Outreach Tactic | Description |
|---|---|
| **Community ambassador initiative** | Conducted early energy assessment visits at the homes of local city leaders to use as ambassadors when promoting the program. |
| **Coordination with city on promotions** | Informed residents about city partnership and special offers through city newsletter. Provided information on the cities' websites with information about available programs and incentives. |
| **Direct mail** | Mailed information about residential opportunities and incentives to targeted households with high summer usage. |
| **Email campaign** | Informed Xcel residential customers about the energy visits and smart thermostat limited offer. |
| **Event tabling** | Provided information about the city partnership and special offers at community (e.g., farmers markets) and city events. Handed out light-emitting diodes (LEDs) at these events throughout the fall. |
| **Manufactured home outreach** | Sent information through manufactured home park newsletters to inform owners about the program, with additional information about income-qualifying programs. |
| **Social media** | Posted graphics and text throughout the summer through city social media channels and shared it with partners, including the utility. |

| Business Outreach Tactic | Description |
|---|---|
| **Business Blitz** | Conducted a door knocking campaign through commercial areas promoting business programs and incentives, including leaving behind a flyer with information. |
| **Coordination with city on promotions** | Engaged city leaders to share information about programs and incentives on the cities' websites, as well as on social media accounts. |
| **Direct engagement by utility account representatives** | Provided information about the programs and incentives to customer-facing utility representatives and call center employees. An email was provided for larger managed accounts from account managers informing them about the limited time offering. |
| **Direct mail to businesses** | Mailing informed all identified businesses about bonus rebates.<br><br>Postcard was mailed to businesses before the business blitz to prepare for upcoming visit and to provide general information. |
| **Trade Ally Engagement** | Held meetings with and provided promotional materials for trade allies in the target region. |

Source: Communication with Center for Energy and Environment

## 6.14 NV Energy's Distributed Resources Plan (2019)

NV Energy submitted its first Distributed Resources Plan to the PUCN in April 2019. The filing included a grid needs assessment that uses several steps (Figure 23) to identify if a traditional distribution system project or NWA is an appropriate solution.

The first step in NV Energy's NWA process is to identify all potential transmission and distribution system constraints or deficiencies. The company relied on its 2018 capital plan and updated information from its distribution planning department in January 2019 to identify 10 candidate distribution system projects. Similarly, NV Energy's fall 2018 capital plan identified 107 candidate transmission upgrade projects.

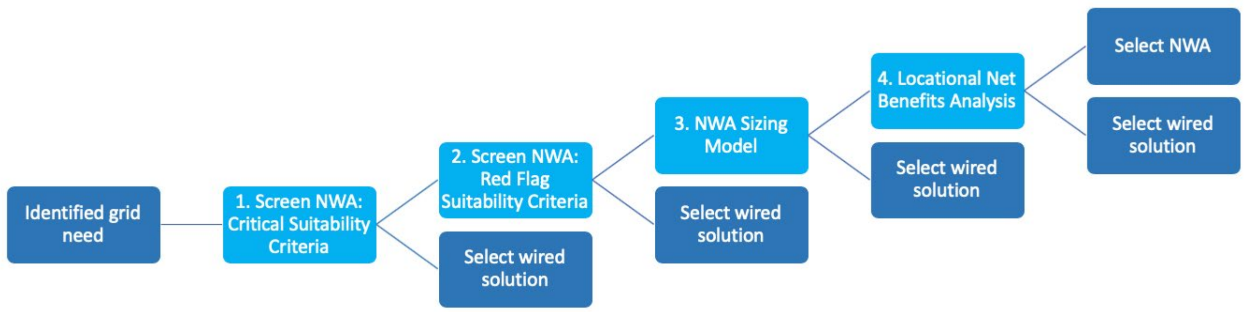


**Figure 23. NV Energy's NWA Process**

The company uses NWA suitability/screening criteria to better identify if a planned T&D capital upgrade project may be deferred or eliminated through NWAs. The suitability/screening criteria are divided into two groups: (1) critical suitability criteria and (2) red flag suitability criteria (Table 14). The criteria are focused on the *timing* and *type* of constraint, as well as on *siting* issues.

**Table 14. NV Energy NWA Suitability/Screening Criteria (NV Energy 2019)**

| Non-Wires Alternative Suitability/Screening |
|---|
| **Critical Suitability Criteria** |
| Is the constraint anticipated to occur between January 1, 2020 and December 31, 2025? |
| Is the constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading or energy consumption, or load shifting, on the transmission or distribution facilities involved would eliminate or defer the constraint? |
| **Red Flag Suitability Criteria** |
| Is the wired solution still within the planning or design stage, with no major equipment on order, received, or installed? |
| Is it reasonable to assume at this time that a Distributed Energy Resources solution will be reliable and safe (i.e., non-critical customers) in this location on the grid? |
| Is it reasonable to assume at this time that local residents would accept a Distributed Energy Resources solution in this area? |
| Is it reasonable to assume at this time that local government agencies would accept a Distributed Energy Resources solution in this area? |
| Is it reasonable to assume at this time that there are no environmental concerns which would preclude a Distributed Energy Resources solution in this area? |
| Is it reasonable to assume at this time that a Distributed Energy Resources solution would be able to be physically located in this area? |

The project must have a planned in-service date between January 1, 2020, and December 31, 2025. The grid constraint must be based on thermal loading, voltage, or reliability so that a reduction in peak demand loading, peak demand energy consumption, or load shifting on the transmission or distribution facilities involved would eliminate or defer the constraint. If the NWA does not meet both critical suitability criteria, it is not a feasible NWA solution for the utility. All 10 distribution system projects and 12 of the 107 transmission projects met the critical suitability criteria in the 2019 DRP.

Red flag suitability criteria include whether major procurement for the "wired solution" has already been initiated, as well as land constraints, environmental permitting constraints, and siting (e.g., safety or customer service issues) relevant to mitigating the grid need. If an NWA does not meet the red flag suitability criteria, it does not necessarily disqualify it as a feasible solution. NV Energy requires the analyst to clearly identify a reason to stop the NWA analysis. Eight of the 10 distribution system projects and all 12 transmission projects met the red flag suitability criteria.

The next step in NV Energy's NWA analysis is using its spreadsheet-based tool, the NWA Sizing Model. The model provides the analyst with several pieces of information:

- Suitability/screening criteria results
- Amount of constraint or deficiency in future years
- Ability of efficiency, demand response, solar PV, and batteries to mitigate the constraint
- Estimate of the NWA portfolio cost
- Comparison of the NWA portfolio and traditional wired solution costs

The NWA Sizing Model approach to creating the NWA portfolio is as follows:

- Reduce demand by 2% to account for energy efficiency
- Identify the optimal amount of demand response and vary the timing to minimize the NWA portfolio estimated cost
- Identify the optimal amount of solar PV that minimizes NWA portfolio estimated cost
- Calculate the remaining energy and demand need and estimate the cost to meet the need using a battery energy storage system

After using the NWA Sizing Model to screen NWA projects, NV Energy identified one distribution and two transmission projects that had similar estimated costs for wired and NWA solutions. Table 15 lists the T&D system projects considered in the NWA Sizing Model in the 2019 DRP.[80] The two rows in bold in the table are distribution system projects whose design and construction had progressed beyond the point at which it would have been reasonable to halt their progress for the purpose of considering alternatives. NV Energy still included these projects in the NWA sizing model for informational purposes. The rows in italics are projects that NV Energy considered in the last step of its NWA analysis, the LNBA.

[80] For additional information on the projects considered by NV Energy see Appendix E.

**Table 15. Potential NWA Solutions for NV Energy's T&D system**

| First Year of Constraint | Substation | Constraint Type | NWA Capacity in 2025 (kW) | | | | NWA Energy in 2025 (kWh) | Cost ($M) | |
|---|---|---|---|---|---|---|---|---|---|
| | | | EE[81] | DR[82] | Solar PV[83] | Battery[84] | Battery[85] | NWA | Wired Solution |
| **2020** | **Sugarloaf** | **Thermal** | **1,370** | **1,300** | **0** | **7,420** | **12,990** | **8.3** | **5.9** |
| **2020** | **Swenson** | **Thermal** | **1,110** | **0** | **18,800** | **16,940** | **174,010** | **115.5** | **2.8** |
| *2021* | *Village* | *Thermal* | *770* | *1,200* | *0* | *400* | *340* | *1.3* | *2.3* |
| *2025* | *Clark-Concourse (trans-mission)* | *Thermal* | *0* | *0* | *0* | *980 kVa* | *440* | *1.60* | *2.3* |

Source: NV Energy (2019)

Analysts performed the LNBA on these two projects. NV Energy's LNBA uses a present worth of revenue requirements (PWRR) analysis to compare the costs of traditional capital upgrade solutions to the costs and potential system-level and locational benefits of NWA solutions.

The utility relied on eight of the eleven costs and benefits associated with distributed generation identified by the PUCN in 2015 (Dockets 15-07041 and 15-07042):

- Transmission upgrade deferral cost
- Distribution upgrade deferral cost
- Transmission upgrade operation, maintenance, administrative, and general expense cost
- Avoided energy
- Generation capacity
- Ancillary services
- T&D losses
- Renewable Portfolio Standard (RPS) integration cost

[81] "A standard amount of megawatt reduction from efficiency was assumed for every NWA portfolio as 2 percent of the maximum loading on that selected day. The 2 percent assumption is greater than the annual energy savings targets of at least 1.1 percent statewide in response to the SB150 (2017) and AB223 (2017), and assumes successful locationally targeted marketing yielding an increased local penetration of efficiency measures in areas where demand reduction is needed to potentially defer a transmission or distribution wired solution."

[82] "A flexible input where the amount of potential megawatt reduction that could be achieved by locationally targeting the existing demand response assets connected to the distribution facility in question can be entered by the user. This does not necessarily represent the amount of reduction expected through normal operation of the demand response program, but what could be achieved through locationally targeting the assets through a specially designed program."

[83] "A flexible input where a megawatt amount of solar capacity can be entered by the user."

[84] "Estimated megawatt power capacity of a battery storage system that would be required to address any remaining megawatt deficiency amount above the rating. NV Energy's spreadsheet tool uses battery storage as the final technology to address any remaining megawatt deficiency."

[85] "After accounting for the energy reduction from the other NWA resources, this is the estimated megawatt-hour energy capacity of a battery storage system that would be required to address any remaining megawatt-hour deficiency amount above the rating. NV Energy's spreadsheet tool uses battery storage as the final technology to address any remaining megawatt-hour deficiency."

- Greenhouse gas emissions
- Reliability/power quality

NV Energy plans to quantify RPS integration cost, greenhouse gas emissions, or reliability/power quality in future LNBA analyses.

The Village substation was the only distribution system project with similar estimated costs for NWA and traditional solutions (see row three in Table 15). The traditional solution used for the comparison was a second 138/12 kV, 37.3 MVA transformer at the substation. The NWA solution tested demand response, solar PV, and energy efficiency. As part of the LNBA, NV Energy refined battery storage costs and ran a sensitivity analysis on a solution that had no energy efficiency or solar PV to determine if demand response alone could meet the system need, and defer the need for a battery as part of the NWA solution.

The results of the LNBA indicated that demand response could meet the forecasted constraint in 2021 and 2022, but that a battery would need to be added in 2023. This resulted in the traditional wired solution being less expensive than the NWA (see Table 15). However, NV Energy is conducting a demonstration project that will use locational dispatch to determine if demand response is a viable option to defer the need for a new transformer until 2023, providing more time for NV Energy to consider system needs and to take into account any changes in substation loading.

The 12 transmission NWA project analyses were divided into solutions for reactive support and projects triggered by forecasted line and transformer overloads. The six traditional wired solutions to meet reactive support (all capacitor bank additions) resulted in mega volt amps reactive (MVAR) capacity additions with low costs. NV Energy's analysis found that to provide a comparable MVAR capacity addition, the NWA for the six projects would need to include a large battery or solar plus a battery, at a cost of $24–$90 million. The result was that the NWA solutions were not able to leverage their main benefit (shifting or reducing load) to meet system needs and were not pursued.

Of the remaining six transmission projects, the Clark–Concourse 138 kV line was the single project considered in the LNBA (last row in Table 15). NV Energy explored whether an NWA could defer the need to reconductor the existing line for one year—from 2025 to 2026. The analysis found that the NWA solution, an energy storage device, was less expensive. But the need to build the wired solution one year later resulted in the NWA solution being more expensive. The NWA was increasingly competitive with the traditional wired solution each year it was deferred. The utility plans to reevaluate cost-competitiveness of the NWA as the transmission need grows more imminent.

In its order on NV Energy's 2019 DRP, the PUCN approved a stipulation by parties to the proceeding that included additional DRP requirements (NV PUC 2019). These include providing a status update on the demand response demonstration project at Village substation in the utility's next DRP. The utility also must consider geo-targeted demand-side management and demand response in future NWA analyses and determine the need for any DER pilot or demonstration project. Additionally, the Commission required NV Energy to consider bulk power storage requirements as part of future analysis of transmission NWAs.

## 6.15 Portland General Electric Smart Grid Test Bed (2019–ongoing)

Portland General Electric's (PGE) pilot program is testing demand flexibility during peak time events[86] to "…help rethink how we use energy through new technologies, programs and products, while still allowing customers to have control over their comfort settings, use more renewable energy, and keeping it reliable and affordable."[87]

Service area-wide, the utility is targeting 69 MW of demand flexibility in summer and 77 MW in winter to fill a 2021 capacity gap identified in its Integrated Resource Plan.[88] For residential customers, PGE is testing a wide range of DER technologies:

- Smart thermostats - bring your own, direct install, and direct shipped
- Ductless heat pump controls
- Heat pump water heaters
- EV chargers
- Batteries

Eligible residential customers served by three distribution substations are enrolled automatically in a peak time rebate program and can decide whether to change their energy profile on an event-by-event basis, with day-ahead notice. To date, more than 16,000 customers (~76% of the Test Bed's residential accounts) have been enrolled, and average event participation is just over 50%. Customers earn a rebate of $1 for each kilowatt-hour in reduced energy consumption during events, compared to their individual usage baseline. The pilot is also testing approaches to move customers from behavioral demand response to an opt-in direct load control program.[89] Distribution substation-level data will help inform technical achievable potential, scenarios and modeling for DERs, and distribution system planning. A planned second phase of the testbed will further explore DERs as non-wires solutions.

Customer value propositions related to demand flexibility are another key part of the pilot. PGE is testing customer drivers such as earning incentives, supporting renewable resources, reducing air pollution, competing with neighbors to reduce peak demand, and donating credits to charity.

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[86] Among the reasons PGE may call events: energy load forecasted to be in the top 1% of annual load hours, forecasted temperature above 90 degrees or below 32 degrees Fahrenheit, expected high generation heat rates and market power prices, and/or forecasted low or transitioning wind generation. PGE will not declare events for more than two consecutive days.
[87] PGE. Smart Grid Test Bed. https://www.portlandgeneral.com/our-company/energy-strategy/smart-grid/smart-grid-test-bed.
[88] PGE filing. 2018. https://edocs.puc.state.or.us/efdocs/UAA/uaa173123.pdf.
[89] PGE news releases. https://www.portlandgeneral.com/our-company/news-room/news-releases/2018/10-11-2018-portland-general-electric-announces-ambitious-smart-grid-test-bed; https://assets.ctfassets.net/416ywc1laqmd/1FXchtG1UCoqK74YIOWBoF/ba8ec453780e26681bde27cb5b8e8fa0/Sched_013.pdf.

For small- and medium-size business customers, PGE is testing direct installation of smart thermostats and plans to add EV charging and storage. The utility also is coordinating with the Energy Trust of Oregon's incentives for energy efficiency upgrades and rooftop solar.

# 7. Areas for Potential Future Research

Utilities have been considering the locational value of DERs to determine if they may be used to defer distribution system investments for several decades. However, many aspects of assessing and using the locational value of DERs remain ripe for future research.

There are limitations today to analysis of avoided distribution costs, both with respect to the methods that may be used and the information utilities typically have on hand. Using the present worth method to determine area-specific avoided costs (as discussed in Chapter 3) is effective, but it requires access to data that currently are not produced by all utilities. The utility case studies in Chapter 6 illustrate that not all types of DERs are considered or that the DER portfolios are not always optimized for an NWA solution. Tariff and program designs incorporating the locational value of DERs are nascent and limited. Additional research is needed to use the locational value of DERs toward achieving state and utility energy goals, as well as understanding consumer response to tariffs and program designs that consider locational value.

The work in our report could be expanded and enriched in several ways. Opportunities for potential future research include:

- Estimating the locational value of large or aggregated grid-interactive efficient buildings
- Identifying opportunities and approaches to include resilience in locational value estimates
- Analyzing examples of state challenges and actions related to expanding DER market participation rules to enable participation and the ability of resources to receive multiple cost streams (e.g., value stacking)
- Describing examples and opportunities to include the locational value of DERs in rate design to enable consumer response
- Incorporating locational value into integrated resource planning
- Identifying opportunities to use the locational value of DERs to defer distribution system investments in high electrification scenarios
- Establishing examples and approaches to compensate DERs for locational value[90]

[90] Reports identifying best practices in compensating DERs are relatively limited (NARUC 2016; SEIA 2018; Orrell, Homer, and Tang 2018; Zinaman et al. 2017). More resources are available on compensating specific DERs (e.g., solar, storage) (EIA 2020b; Stanton 2019; Stanfield, Petta, and Auck 2017).

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# Appendix A. Evolution of Approaches to Estimate Locational Value

The genesis of incorporating locational value in the assessment of distributed energy resources (DERs) was in the late 1980s. Electric utilities have conducted local distribution system planning since their inception, and they have computed system-average (non-locational) marginal costs of distribution capacity for ratemaking purposes for decades prior. However, in the late 1980s, Pacific Gas and Electric Company (PG&E), in collaboration with the Electric Power Research Institute (EPRI), evaluated and deployed large amounts of DER based on the high value of local capacity relief in a few hours in the right locations. The first of these projects was a large solar PV installation near the Kerman substation in California's Central Valley (large for the time at 500 kilowatts [kW]), and the second of these projects was in the San Francisco Bay Delta, which focused on targeted deployment of air conditioner energy efficiency to avoid a subtransmission upgrade.

From the early 1990s through the electric industry restructuring wave in the late 1990s, seminal academic publications were produced describing how to decompose the avoided distribution capacity value by location and time for DER evaluation (see below). In addition, a number of utility case studies were completed that tested the ability to target DERs in specific locations and deploy resources based in part on their locational value (see the utility case studies in Chapter 6).

- *Area- and Time-Specific Marginal Costs of Electric Distribution* (Woo et. al. 1994). This paper provides the clearest description of best practice in calculating forward looking distribution capacity costs for distribution planning. The paper describes the present worth method (also known as the *differential revenue requirement method*) for calculating avoided costs based on future distribution capacity plans.

- *The use of area-specific utility costs to target intensive DSM campaigns* (Swisher and Orans 1995). This paper uses the same method for marginal distribution capacity costs, and includes it in the California Standard Practice Manual (SPM) cost-effectiveness tests for energy efficiency. This extends the range of benefits to include system energy, capacity, and other components of value in an integrated resource planning (IRP) basis.

- *Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation* (Woo et. al. 1995). This paper calculates the marginal distribution value for each distribution planning area in two utilities (Pacific Gas and Electric and Public Service of Indiana). With the full service territory evaluated, the economic potential of distributed generation is evaluated using the net capacity cost of distributed generation.

- *The Distributed Utility: A New Electric Utility Planning and Pricing Paradigm* (Feinstein, Orans and Chapel 1997). This paper summarizes a broader vision of a utility planning approach that decomposes costs by area and time to fully evaluate the opportunities for distributed resources.

- *Costing Methodology for Electric Distribution System Planning* (E3 and Pacific Energy Associates 2000). This study reviews the range of methods used to evaluate the value of distribution system capacity. The value of a forward-looking marginal distribution capacity cost is highlighted, along with the increased benefit of an hourly disaggregation. This study was funded by the Energy Foundation and presented at a NARUC conference to support development of best practices in the topic.

Beginning in the 1990s and through today, the prevailing approach for assessing the locational value of DER in a specific area is to compare its costs and benefits to the ratepayer value of deferring the traditional capital investments needed to alleviate local capacity constraints. The method is sometimes called the *differential revenue requirement method,* which calculates the difference in revenue requirement between a distribution project built on its planned schedule versus one that is deferred in time through deployment of an NWA. This approach also factors in the necessary timing and certainty of load reduction provided by DER in the constrained location to avoid the investment, and a comparison of the ratepayer costs of deploying and operating DER relative to the deferral value. In contrast, the system-average marginal cost of service studies used for ratemaking are largely based on historical investments made relative to historical growth and provide a long-run marginal cost, but not the value of any specific DER deployed in a particular area.

Post-restructuring in the 2000s, many utility studies were conducted to evaluate NWAs, particularly for high profile reinforcement projects, and particularly for those that required right-of-ways or land use that attracted public scrutiny. In the restructuring settlement agreements in the late 1990s, New York included a requirement for their utilities to evaluate NWAs for major projects above a certain cost threshold. In addition, many cities across North America faced the need to build expensive and sometimes unpopular new transmission to serve growing load in the urban centers, which raised the question of available DER alternatives. Providing additional supply to metropolitan areas in San Francisco, New York, Seattle, Toronto, Chicago, Philadelphia, Nashville, and other cities led to a number of locational-specific DER studies that evaluated the potential to cost-effectively deploy DERs as an NWA (see the utility case studies in Chapter 6).

In the 2010s, there has been a resurgent effort to deploy DERs as a local resource to provide local capacity value, as well as a range of system-related benefits. These efforts take advantage of new technology in controls and communication, better load and customer data that are acquired through advanced metering infrastructure (AMI) and lower cost DERs such as efficiency, battery storage, and solar PV.

As utilities update their distribution planning processes and learn how best to take advantage of additional data, the future looks aligned for utilities, energy services companies, and customers to provide greater control of their loads and behind-the-meter resources as additional technology becomes available. In particular, there is a greater saturation of connected thermostats and energy management systems, increasing penetration of electric vehicles with scheduled charging capability, and decreasing costs of distributed battery storage, all of which can provide targeted local capacity relief.

# Appendix B. Grid Services That Demand Flexibility in Buildings Can Provide

**Table B-1. Grid Services**

| Demand Side Management Strategies | Grid Services | Description of Building Change | Key Characteristics | | | |
|---|---|---|---|---|---|---|
| | | | Duration | Load Change | Response Time | Event Frequency |
| Efficiency | *Generation: Energy*<br>*Generation: Capacity*<br>*T&D: Non-Wires Solutions* | Persistent reduction in load. Interval data may be needed for M&V purposes. This is not a dispatchable service. | Continuous | Long term decrease | N/A | Lifetime of equipment |
| Shed Load | ***Contingency Reserves*** | Load reduction for a short time to make up for a shortfall in generation. | Up to 1 hr | Short term decrease | <15 min | 20 times per year |
| Shed Load | ***Generation: Energy***<br>***Generation: Capacity***<br>***T&D: Non-Wires Solutions*** | Load reduction during peak periods in response to grid constraints or based on time-of-use (TOU) pricing structures. | 2 to 4 hrs | Short term decrease | 30 min to 2 hrs | <100 hrs per yr/seasonal |
| Shift Load | *Generation: Capacity*<br>*T&D: Non-Wires Solutions* | Load shifting from peak to off-peak periods in response to grid constraints or based on TOU pricing structures. | 2 to 4 hrs | Short term shift | <1 hour | <100 hrs per yr/seasonal |
| Shift Load | *Contingency Reserves* | Load shift for a short time to make up for a shortfall in generation. | Up to 1 hr | Short term shift | <15 min | 20 times per year |
| Shift Load | *Avoid Renewable Curtailment* | Load shifting to increase energy consumption at times of excess renewable generation output. This is not a dispatchable service but can be reflected through TOU pricing. | 2 to 4 hrs | Short term shift | N/A | Daily |
| Modulate Load | ***Frequency Regulation*** | Load modulation in real time to closely follow grid signals. Advanced telemetry is required for output signal transmission to grid operator; must also be able to receive automatic control signal. | Seconds to minutes | Rapid increase/decrease | <1 min | Continuous |
| Modulate Load | ***Voltage Support*** | | Sub-seconds to seconds | Rapid increase/decrease | Sub-seconds to seconds | Continuous |
| Modulate Load | ***Ramping*** | Load modulation to offset short term variable renewable generation output changes. | Seconds to minutes | Rapid increase/decrease | Seconds to minutes | Continuous |
| Generate | *Ramping* | Distributed generation of electricity to dispatch to the grid in response to grid signals. This requires a generator or battery and controls. | Seconds to minutes | Rapid dispatch | Seconds to minutes | Daily |
| Generate | *Generation: Energy*<br>*Generation: Capacity*<br>*T&D: Non-Wires Solutions* | | 2 to 4 hrs | Dispatch/negative load | <1 hour | <100 hrs per yr/seasonal |
| Generate | *Generation: Energy*<br>*Generation: Capacity*<br>*T&D: Non-Wires Solutions* | Distributed generation of electricity for use onsite and, when available, feeding excess electricity to the grid. This is not a dispatchable service, though metered data is needed. | Entire generation period | Reduction/negative load | N/A | Daily |

Note: Response time is the amount of time between receiving a signal from the utility or regional grid operator and the building asset responding to change the load. Duration is the length of time that the load change occurs.

# Appendix C: Screening Tool

The purpose of a screening tool is to work through key questions in an organized manner and eliminate projects with limited opportunity for distributed energy resources (DERs) as an NWA early in the process. The screening process allows distribution system planning staff to focus their analysis on areas with the greatest likelihood of success.

One example tool for screening the ability of DER to defer a traditional NWA evaluation is included in Figure C-1 below. This example is borrowed from Orange and Rockland Utilities that serves areas of New York, Pennsylvania, and New Jersey. Variations of similar criteria have been applied at a number of utilities as a way to collect the necessary data and do a preliminary screen for all projects.[91] The four categories of interest are the following:

- Project applicability: The nature of the problem and whether DER can solve it
- Project timeline: Whether there is time to implement a targeted DER program in the area
- Project cost: The potential value for avoiding the investment
- Maximum incentive levels: The marginal avoided cost of local value ($/kW)

To estimate the value of transmission and distribution system savings, the *present worth* or *differential revenue requirement* method is used to isolate the distribution capacity value of the specific deferral. The distribution capacity value also provides the maximum contract payment or incentive that can be paid to customers to target DER into the area without increasing costs to ratepayers more than the traditional wires solution would. If this value is low, then there is less likelihood that customers would participate in a targeted DER program.

[91] For example, Bonneville Power Administration and Consolidated Edison have incorporated screening criteria into their assessment of NWAs. See https://www.ethree.com/tools/idsm-integrated-demand-side-management-model/.

**Capacity Expansion DER Screening Checklist** *Page 1 of 3*

Project Name: Example Substation | In Service Date: 2018

Description: Analysis - Avoid distribution ties and New Example sub

Author: | Date of Review:

**Project Applicability**

1. Can load reduction or generation solve this problem? Yes *If no stop*

*If no, please identify the main project driver(s) below:*

- ☐ Replace obsolete / aging equipment
- ☐ Improve reliability through secondary source etc.
- ☐ Work at the request of others
- ☐ Add operational flexibility
- ☐ Other : ____________________
- ☐ Correct poor reliability problem
- ☐ Comply with PSC standards
- ☐ Safety
- ☐

2. Is the project entirely within ISO or FERC jurisdiction? No *If yes, stop*

**Project TimeLine**

| Current Date | RFP Lead Time (months) | Project Commitment Date | Construction lead time | Project in-Service Date |
|---|---|---|---|---|
| 2/1/2016 | 12 | 2/1/2017 | 14.9 | 5/1/2018 |

3. Is the project need date at least 18 months in the future? **Yes** *If no stop*
4. Is the major project commitment date closer than ___ months in the future? **Yes** *If no, stop*

**Project Cost**

All costs in constant dollars

| Expense Year | Energized Year | Total Cost ($000) | Excluded cost ($000) | Net Cost (000) | Equipment (Select) |
|---|---|---|---|---|---|
| 2016 | 2018 | $ 1,162 | $ 1,162 | $ - | Dist OH Circuit |
| 2017 | 2018 | $ 1,340 | $ 1,340 | $ - | Dist OH Circuit |
| 2017 | 2018 | $ 960 | $ 960 | $ - | Dist OH Circuit |
| 2018 | 2018 | $ 6,337 | $ - | $ 6,337 | Dist Sub |
| | | | | $ - | Dist UG Circuit |
| | | | | $ - | Trans OH Circuit |
| | | | | $ - | Trans UG Circuit |
| | | | | $ - | Trans Sub |
| | Total Cost | $ 9,799 | $ 3,462 | $ 6,337 | |

*Exclude land costs, if there are risks of land cost increases or loss of parcel availability*

5. Is the total project cost >= $500,000 **Yes** *If no, stop*

**Avoidable Cost Levels - Contract** *Page 2 of 3*

**DER Peak Load reduction (MW) needed to defer the project**

| Year: | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2013 |
|---|---|---|---|---|---|---|---|---|---|---|
| Minimum Total MW: | 5.0 | 5.5 | 5.9 | 6.4 | 6.8 | 7.3 | 7.7 | 8.2 | 8.6 | 9.1 |

| Avoidable Costs | 1 Year | 2 Year | 3 Year | 4 Year | 5 Year | 6 Year | 7 Year | 8 Year | 9 Year | 10 Year |
|---|---|---|---|---|---|---|---|---|---|---|
| $/kW (contract) | $ 97.72 | $ 173.99 | $ 234.00 | $ 281.47 | $ 319.10 | $ 348.94 | $ 372.52 | $ 391.03 | $ 405.40 | $ 416.38 |
| $/kW-yr (level) | $ 97.72 | $ 89.65 | $ 82.81 | $ 76.95 | $ 71.85 | $ 67.39 | $ 63.46 | $ 59.95 | $ 56.81 | $ 53.99 |
| Maximum Incentive | $ 488,605 | $ 948,230 | $ 1,380,595 | $ 1,787,316 | $ 2,169,914 | $ 2,529,820 | $ 2,868,380 | $ 3,186,860 | $ 3,486,451 | $ 3,768,273 |

6. Is the total avoidable cost in any year greater than $ ___ / kW
7. Is the project sum of avoidable cost over all years greater than $ ___ / kW
8. Are either or both questions "yes" *If no, stop*

Discount rate: 8.75% | Revision Date: *Discount rate from Capital Accounting*

Inflation rate: 2.30% | Revision Date: *Inflation from Capital Accounting*

**Recommendation**

Candidate for RFP? (Y/N): | If no, reason:

Reviewer: | Date of Review:

**Figure C-1. Example Screening Tool Which Would be Customized and Included in the Regular Process of Screening for DERs**

# Appendix D: Examples of Publicly Available Tools

## D.1 DER Valuation Tools: Single Solution

### Consolidated Edison – BQDM Program Cost-Benefit Model – February 2019

- **Description:** The BQDM Program Cost Benefit Model is updated semiannually by Consolidated Edison to reflect the cost-effectiveness of the Brooklyn Queens Demand Management Demand Response Program. The most recent (February 2019) benefit-cost analysis (BCA) update has begun to incorporate additional procurement activities and related deferral of the Glendale Project that the Commission approved in the Extension Order. Consolidated Edison will continue to include additional procurement activities during the extension period. As in previous BCA updates, the model uses 2014$ values. The model reflects the BQDM achievements to date, projected load reductions, and updated load forecasts. The BCA approach established through the BCA Handbook (BCAH) differs from the BCA methodology initially used for BQDM, with differences including the BCAH's use of post-tax weighted adjusted cost of capital (WACC) instead of the pre-tax WACC previously used, use of a societal test that provides for increased benefits related to carbon emission reductions, as well as increased costs related to distributed energy resources (DER) from using the total cost of the DER instead of the utility incentive alone.
- **Link:** http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FE8266ED-ECFB-4043-B743-9C59E2352C24}

The Consolidated Edison tool can also be modified and used in other jurisdictions. Synapse Energy Economics adapted the tool for analysis for the Department of Energy and Environment (DOEE) in the Mt. Vernon case study discussed in Chapter 6.

Consolidated Edison also developed an avoided cost model that feeds into this cost-benefit model.[92]

### E3 – Avoided Cost Calculator

- **Description:** The California "Avoided Cost Calculator" is an Excel-based spreadsheet model produced by E3 for use in demand-side cost-effectiveness proceedings at the CPUC. Specifically, the model produces an hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours. These avoided costs are the benefits that are used in determining the cost-effectiveness of these resources.
- **Link:** https://www.cpuc.ca.gov/General.aspx?id=5267

### Long Island's Public Service Enterprise Group (PSEG) – VDER Value Stack Calculator

- **Description:** This tool is largely similar to the rest of the state's Value of Distributed Energy Resources (VDER) program with a couple important differences. First, the mass market (residential, and non-demand commercial) off-takers of community distributed generation

[92] See September 27, 2019, BQDM BCA model and Avoided Cost model filings in Docket 14-E-0302: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=DF49F419-DCE5-4E9B-8EE6-E77F1C77680A; http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=0AA37573-62A6-4495-B2D0-CD1E7899038A; http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=BD152780-F88E-4EDD-9EF2-9FCD90D01B11.

projects will receive volumetric crediting rather than monetary crediting through the value stack. Second, projects receiving Installed Capacity (ICAP) Alternative 3 will have their compensation based on grid injections over the top 10 hours of annual peak utility demand, rather than on the single top hour.

- **Link:** https://www.psegliny.com/businessandcontractorservices/businessandcommercialsavings/greenenergy/vder

### New York Solar Value Stack Calculator

- **Description:** This calculator combines the wholesale price of energy with the distinct elements of DER that benefit the grid: the avoided carbon emissions, the cost savings to customers and utilities, and other savings from avoiding expensive capital investments.
- **Link:** https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator

## D.2 DER Valuation Tools: Portfolio of Solutions

### E3 – Locational Net Benefit Analysis (LNBA) Tool

- **Description:** The LNBA calculates locational avoided costs for utility local transmission and distribution (T&D) projects, as well as avoided cost/benefits for a load reduction shape. The tool provides a summary of total avoided costs by component and technology and can also simulate multiple savings/revenue streams: T&D deferral, interconnection costs reduction, utility programs, grid services/bill savings, and back-up power. Users can perform a portfolio analysis for a suite of DER technologies across the system. They also can select how to perform the peak reduction and deferral valuation, using the: (1) peak reduction discount method or (2) deferral values accounting method.
- **Link:** https://e3.sharefile.com/share/view/sf3b5f091144489ca

### E3 – Integrated Demand Side Management (IDSM) Model

- **Description:** The E3 IDSM model assesses the market potential and economics of DER technologies for electric utilities. The IDSM tool identifies local market potential for each DER technology type for the study area, and then selects the least-cost portfolios that integrate DERs and meet utility reliability criteria. The tool's algorithm dispatches DER technologies for input rate designs or market prices. It evaluates a full range of potential lifecycle benefits, including avoided bulk system capacity, energy, transmission capacity, distribution capacity, ancillary services, air emissions, and environmental externalities. E3 has customized the tool for many utilities throughout North America, including Consolidated Edison, Pacific Gas and Electric Company, and Bonneville Power Administration.
- **Link:** https://www.ethree.com/tools/idsm-integrated-demand-side-management-model/

### E3 – Solar + Storage Optimization Tool

- **Description:** This tool estimates the value proposition of the integrated solar and storage systems based on their expected optimal operations, location on the grid, market prices, and other characteristics. The tool also evaluates the operations of distributed solar + storage in combination with other controllable DER technologies such as smart thermostats, electric vehicle chargers, and similar devices. These combinatory scenarios provide insights on the synergy among multiple technologies and their integrated impacts on distribution deferral values and customers' bills. In addition to the existing programs and revenue streams, the tool also provides great flexibility in evaluating future rates, demand response, and resource adequacy program designs.

- **Link:** https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program/modeling-tool-maximize

### National Renewable Energy Laboratory (NREL) – REopt: Renewable Energy Integration & Optimization

- **Description:** The REopt™ model provides concurrent, multiple technology integration and optimization capabilities to help organizations meet their cost savings and energy performance goals. Formulated as a mixed integer linear program, the REopt model recommends an optimally sized mix of renewable energy, conventional generation, and energy storage technologies; estimates the net present value of implementing those technologies; and provides a dispatch strategy for operating the technology mix at maximum economic efficiency. Under development at NREL since 2007, the REopt model was initially created to identify and prioritize cost-effective renewable energy projects across a portfolio of sites. The model is now also used to optimize the size and operating strategy of microgrids, storage, and energy/water systems. NREL's REopt analyses have supported decisions that led to more than 260 megawatts (MW) of renewable energy development.
- **Link:** https://reopt.nrel.gov/

### Lawrence Berkeley National Laboratory (Berkeley Lab) – Distributed Energy Resources-Customer Adoption Model (DER-CAM)

- **Description:** The DER-CAM is a powerful and comprehensive decision support tool that primarily serves the purpose of finding optimal DER investments in the context of either buildings or multi-energy microgrids. DER-CAM uses advanced mathematical modeling techniques to formulate the optimal multi-energy microgrid design problem as a mixed-integer linear program (MILP). Unlike simulation-based models or optimization models based on heuristic and non-linear formulations, this allows DER-CAM to quickly find globally optimal solutions to this highly complex problem. The key challenge lies in developing and implementing linear formulations that adequately represent different non-linear phenomena, and DER-CAM achieves this using a wide range of techniques. This widely accepted and extensively peer-reviewed model has been developed by Berkeley Lab since 2000, and can be used to find the optimal portfolio, sizing replacement, and dispatch of a wide range of DER, while co-optimizing multiple stacked value streams that include load shifting, peak shaving, power export agreements, or participation in ancillary service markets.
- **Link:** https://building-microgrid.lbl.gov/projects/der-cam

## D.3 Battery Storage Valuation Tools

### Ascend Analytics – BatterySimm™

- **Description:** This tool identifies configurations and operating strategies to maximize value. BatterySimm's advanced algorithms help developers and utilities define and implement strategies to co-optimize the joint value for both energy and ancillary services markets. BatterySimm™ has three different modules to maximize project value through any point of the project life. The first module optimizes the storage sizing for energy cycling capabilities and duration specifications. The second module valuates projects under both perfect and imperfect foresight of energy and ancillary service prices. Finally, the third module determines optimal operating strategies for independent system operator (ISO) bidding and integrated utility operations. Maximizing value means optimizing battery charge and discharge strategy across day-ahead and real-time energy and ancillary service markets under real-life conditions, inclusive of physical battery performance attributes over time.

- **Link:** https://www.ascendanalytics.com/solutions/batterysimm-suite.

### Brattle – bSTORE

- **Description:** The bSTORE modeling suite is a storage simulation and decision-support platform used to assess the value of storage projects. bSTORE provides insights into a different aspect of storage value that can be utilized separately or in conjunction with one another. The tool provides a number of advantages that make it uniquely suited for assessing the multiple value streams of storage. There are six modules in this tool: (1) Optimal Bidding and Dispatch, (2) Market Impact, (3) Capacity Expansion, (4) Customer Retail Cost, (5) Customer Reliability Benefits, and (6) T&D System Benefits. The optimal bidding and dispatch module produces scheduling strategies under real-world market conditions and maximizes the wholesale market value of storage assets through co-optimization of day-ahead energy, ancillary services, and real-time energy markets under uncertainty. The market impact module considers regionwide, zonal, and nodal impacts of large-scale storage development. The capacity expansion model considers the resource adequacy and flexibility value of storage. The transmission and distribution module considers the avoided or deferred T&D costs. The customer retail cost module looks at the customer rate impacts of utility-owned or utility-contracted distribution and transmission level storage. Finally, the customer reliability benefits module assesses the value of customer outage reduction through distributed storage.
- **Link:** https://www.brattle.com/bstore

### E3 – RESTORE Model

- **Description:** RESTORE evaluates the costs and benefits of energy storage in the transition to a low-carbon, high-renewables grid, co-optimizing the dispatch across energy, capacity, and ancillary service markets for transmission, distribution, and customer-sited energy storage. Using market price projections, RESTORE shows the future value of energy storage in a low-carbon, high-renewables grid that conventional utility evaluation protocols do not adequately capture. RESTORE also incorporates E3's industry-leading expertise in distributed energy resource planning to fully capture the local distribution and ratepayer impacts of behind-the-meter storage.
- **Link:** https://www.ethree.com/tools/restore-energy-storage-dispatch-model/.

### EPRI – Storage Value Estimation Tool (StorageVET®)

- **Description:** A publicly available, open-source, Python-based energy storage valuation tool. Made possible through funding support from the California Energy Commission. StorageVET 2.0 is an open-source valuation tool for energy storage systems based on perfect foresight dispatch optimization. StorageVET 2.0 is capable of modeling many concurrent "stacked" services provided by a single storage system. Optional pairing with a non-dispatchable generator, like solar or wind, is available.

- **Link:** https://www.storagevet.com/.

### Navigant/TenneT – Electricity Storage Valuation Tool

- **Description**: TenneT's free tool allows users to independently analyze business cases for large-scale electricity storage. The tool uses a powerful method to determine the optimal dispatch of storage assets for specific applications and includes a comprehensive set of technical and economic parameters for large-scale storage projects. It can also be used to perform financial analyses. Users can select one of the predefined example cases, or define your own projects. The tool controls about 45 parameters ranging from technology performance to project design, financing options, and market price series. The model assesses the maximum revenue by means of a dispatch optimization (on 15 min or hour level). It provides the user with a detailed breakdown of net present value components and cash flow over the project lifetime.
- **Link:** https://www.tennet.eu/electricity-market/dutch-market/electricity-storage-tool/.

### Sandia National Laboratories – Quest

- **Description:** QuESt v1.2 features the debut of *QuESt BTM*, an application aimed at providing analysis tools for behind-the-meter energy storage. The first of these tools estimates the cost savings provided by energy storage for time-of-use and net energy metering customers. By strategically using energy storage, the customer can reduce his or her time-of-use energy charges or reduce demand charges by peak shaving. Energy storage can also be used with on-site solar power to reduce the customer's monthly bill by time-shifting. QuESt BTM uses simulated load profiles of different commercial and residential buildings located around the United States. It leverages a database of U.S. utility rate structures to allow users to select the rate structure most pertinent to his or her project. Additionally, QuESt BTM can utilize simulated solar power profiles for projects with energy storage co-located with, for example, rooftop solar. By simulating different energy storage system configurations, QuESt BTM can help users size the appropriate energy storage system for reducing his or her building's monthly electricity bills.
- **Link:** https://energy.sandia.gov/sandia-releases-quest-v1-2/.

## Hosting Capacity Maps

### California Integrated Capacity Analysis (ICA) Maps

- **Description:** Since 2016, PG&E, SDG&E, and SCE have shared detailed data on DER hosting capacity across their thousands of distribution grid circuits as part of fulfilling their mandate under the CPUC's distribution resources plan. They're built using the same data that's informing the utilities' Locational Net Benefits Analysis and the Distribution Deferral Opportunity Reports, which represent a first step into contracting for DER NWAs for the distribution grids. They've become an important tool for developers of solar, energy storage, and other DER projects to avoid interconnection constraints and target high-value areas.
- **Links**
    - PG&E: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page.

- SDG&E: https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica.
- SCE: https://www.arcgis.com/home/item.html?id=8aad048ffcd54c69a29e1fde77700962.

**New York Hosting Capacity Maps**

- **Description:** The hosting capacity map displays are a high-level estimate of the available hosting capacity for adding distributed generation. *Hosting capacity* is defined as the amount of generation that can be accommodated at a point on the distribution system without requiring mitigations such as specialized inverter settings or infrastructure upgrades. The locational system relief value (LSRV) is an added credit for DER installations in eligible areas where the utility grid would benefit from additional generation capacity. LSRV areas will display a status of "Eligible" on the Hosting Capacity map under "LSRV Area Information." As part of the Hosting Capacity Portal, utilities also provide aggregated distributed generation (DG) values at the substation level. These values are representative of the total amount of DG that is installed on the feeders and networks associated with the area substation. These data can be accessed by selecting a feeder or network on the mapping display and advancing to the associated data pane. Currently, all hosting capacity maps require a utility account to access them.
- **Links**
    - National Grid: http://ngrid.maps.arcgis.com/apps/MapSeries/index.html?appid=4c8cfd75800b469abb8febca4d5dab59&folderid=8ffa8a74bf834613a04c19a68eefb43b.
    - Consolidated Edison: https://www.coned.com/en/business-partners/hosting-capacity.
    - Central Hudson: https://www.cenhud.com/my-energy/distributed-generation/hosting-capacity-map/.
    - Orange & Rockland: https://www.oru.com/en/business-partners/hosting-capacity.
    - NYSEG: http://iusamsda.maps.arcgis.com/apps/webappviewer/index.html?id=2f29c88b9ab34a1ea25e07ac59b6ec56.
    - Rochester Gas & Electric (RG&E): http://iusamsda.maps.arcgis.com/apps/webappviewer/index.html?id=2f29c88b9ab34a1ea25e07ac59b6ec56.

# Appendix E. Additional State and Utility Case Study Material

**Table E-1. NV Energy forecasted distribution system constraints and potential NWA solutions**

| | | | NWA Capacity in 2025 (kW) | | | | NWA Energy in 2025 (kWh) | Cost ($millions) | |
|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Substation** | **Constraint Type** | **EE[2]** | **DR[3]** | **PV[4]** | **Battery[5]** | **Battery[6]** | **NWA** | **Traditional Wired Solution** |
| 2020 | Silver Springs | Reliability | 140 | 0 | 7,200 | 6,610 | 88,960 | 55.2 | 3.2 |
| 2020 | Silver Lake | Thermal | 1,100 | 800 | 0 | 8,770 | 48,580 | 25.4 | 3.1 |
| 2020 | Speedway | Thermal | 1,170 | 0 | 20,300 | 8,710 | 98,170 | 79.8 | 2.9 |
| **2020** | **Sugarloaf** | **Thermal** | **1,370** | **1,300** | **0** | **7,420** | **12,990** | **8.3** | **5.9** |
| **2020** | **Swenson** | **Thermal** | **1,110** | **0** | **18,800** | **16,940** | **174,010** | **115.5** | **2.8** |
| 2021 | Tomsik | Thermal | 1,700 | 2,400 | 2,300 | 8,640 | 33,800 | 23.5 | 1.8 |
| *2021* | *Village* | *Thermal* | *770* | *1,200* | *0* | *400* | *340* | *1.3* | *2.3* |
| 2022 | Beltway | Thermal | 910 | 950 | 2,400 | 6,730 | 22,740 | 16.0 | 2.0 |
| 2022 | Ray Couch | Reliability | 200 | 0 | 0 | 2,800 | 18,670 | 9.5 | 1.7 |
| 2025 | Golconda[1] | Reliability | 40 | 0 | 2,600 | 2,100 | 36,000 | 21.9 | 2.2 |

Source: NV Energy (2019).

**Table E-2. NV Energy forecasted transmission system constraints and potential NWA solutions**

| | | | NWA Capacity in 2025 (kW) | | | | NWA Energy in 2025 (kWh) | Costs ($millions) | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Substation | Facility and Constraint Type | EE[2] | DR[3] | Solar[4] | Battery (kVA) | Battery | NWA | Traditional Wired Solution |
| 2020 | Dove | Capacitor Voltage | 0 | 0 | 0 | 90,000 | 180,000 | 90 | 1.2 |
| 2023 | Artesian | Capacitor Voltage | 0 | 0 | 0 | 24,000 | 24,000 | 24 | 1.5 |
| 2023 | Sinatra | Capacitor Voltage | 0 | 0 | 0 | 24,000 | 24,000 | 24 | 1.3 |
| 2023 | Millers | Line Fold Thermal | N/A | N/A | N/A | N/A | N/A | N/A | 12.8 |
| 2023 | Pecos | Transformer Thermal | N/A | N/A | N/A | N/A | N/A | N/A | 11 |
| 2024 | Burnham | Capacitor Voltage | 0 | 0 | 0 | 24,000 | 24,000 | 24 | 1.2 |
| 2024 | Northwest | Transformer Thermal | 7,600 | 0 | 0 | 32,300 | 124,500 | 68.1 | 9.8 |
| 2025 | McDonald | Capacitor Voltage | 0 | 0 | 0 | 24,000 | 24,000 | 24 | 1.2 |
| 2025 | Tropical | Capacitor Voltage | 0 | 0 | 0 | 24,000 | 24,000 | 24 | 1.2 |
| *2025* | *Clark* | *Line Upgrade Thermal* | *0* | *0* | *0* | *980* | *440* | *1.6* | *2.3* |
| 2025 | Mission | New Line Reliability | 0 | 0 | 0 | 71,000 kW | 156,000 | 78.4 | 12.8 |
| 2025 | Flamingo | Line Upgrade Thermal | N/A | N/A | N/A | N/A | N/A | N/A | 18.2 |

Source: NV Energy (2019).

Notes:

(1) All facility types are transformers except Golconda, which is a feeder.

(2) "A standard amount of megawatt reduction from efficiency was assumed for every NWA portfolio as 2 percent of the maximum loading on that selected day. The 2 percent assumption is greater than the annual energy savings targets of at least 1.1 percent statewide in response to the SB150 (2017) and AB223 (2017), and assumes successful locationally targeted marketing yielding an increased local penetration of efficiency measures in areas where demand reduction is needed to potentially defer a transmission or distribution wired solution."

(3) "A flexible input where the amount of potential megawatt reduction that could be achieved by locationally targeting the existing demand response assets connected to the distribution facility in question can be entered by the user. This does not necessarily represent the amount of reduction expected through normal operation of the demand response program, but what could be achieved through locationally targeting the assets through a specially designed program."

(4) "A flexible input where a megawatt amount of solar capacity can be entered by the user."

(5) "Estimated megawatt power capacity of a battery storage system that would be required to address any remaining megawatt deficiency amount above the rating. NV Energy's spreadsheet tool uses battery storage as the final technology to address any remaining megawatt deficiency."

(6) "After accounting for the energy reduction from the other NWA resources, this is the estimated megawatt-hour energy capacity of a battery storage system that would be required to address any remaining megawatt-hour deficiency amount above the rating. NV Energy's spreadsheet tool uses battery storage as the final technology to address any remaining megawatt-hour deficiency."

**Table E-3. New York Non-Wires Alternative Projects**

| Utility | Project Name | Project Need and Size[1] | Project Status | Year Needed |
|---|---|---|---|---|
| **Central Hudson[2]** | Phillips Road Substation | Defer new substation by procuring 5 MW load relief | Demand reduction program underway | 2018 |
| | Merritt Park Distribution Feeder Upgrade | Defer upgrade of 2 distribution feeders by procuring 1 MW load relief | Demand reduction program underway | 2019 |
| | Northwest Corridor Transmission Upgrade | Defer transmission upgrade by procuring 10 MW load relief | Demand reduction program underway | 2019 |
| | Coldenham Distribution Feeder Upgrade | Defer distribution feeder upgrade by procuring 1 MW load relief | On hold – wires solution pursued | 2019 |
| **Consolidated Edison[3]** | Brooklyn/Queens Demand Management | Total 63 MW relief needed | 52 MW complete, 11 MW in active procurement | 2018 / 2021 |
| | Water Street Cooling Project | Water Street Substation load relief needed (Brooklyn) | Evaluating relief proposals | 2019 |
| | Plymouth Street Cooling Project | Plymouth Street Substation load relief needed (Brooklyn) | Evaluating relief proposals | 2019 |
| | Cable Crossing - Flushing | Overload projected for six distribution feeders in Flushing Network (Queens) | Opportunity will not proceed | 2019 |
| | Primary Feeder Relief - Williamsburg | Overloads projected in Williamsburg Network (Brooklyn) | Evaluating relief proposals | 2020 |
| | Water/Plymouth Energy Storage | 32 MW load relief needed | Active procurement | 2020 / 2021 |
| | Primary Feeder Relief - Columbus Circle | Overloads projected in Columbus Circle Network (Manhattan) | Opportunity will not proceed | 2021 |
| | Primary Feeder Relief - Hudson | Overloads in Hudson Network (Manhattan) | Opportunity will not proceed | 2021 |
| | Primary Feeder Relief - Chelsea | 3.2 MW load relief needed (Manhattan) | Project deferred due to decease in load projection | 2021 |
| | Parkchester No. 1 Cooling Project | 6 MW load relief needed (South Bronx) | Project deferred due to decease in load projection | 2021 |
| | Load Transfer W42 No. 1 to Astor | Displace load transfer between W42 Street Substation and Astor Substation | Evaluating relief proposals | 2022 |

| | | | | |
|---|---|---|---|---|
| | W. 65th Street #1 | Bus upgrades needed | Project pushed back to 2025 | 2025 |
| | Yorkville Crossing | Need to bifurcate feeders at Hellgate Area Station | Opportunity will not proceed | |
| **National Grid**[4,5] | Sawyer 11H Sub-transmission Line | 1.7 MW load relief needed by 2020 | Revising load forecast – may reissue | 2020–30 |
| | Van Dyke | Relief needed for projected overload on substations serving Bethlehem, New Scotland, and Albany | Evaluating relief proposals | 2020 |
| | Fairdale D-Sub | Relief needed for projected overload on Fairdale Substation | Solicitation closed | 2020 |
| | Forbes Ave – New Substation & D-Line L | Relief needed for projected overload for substation and sub-transmission lines serving Rensselaer NY | Solicitation closed | 2020 |
| | Buffalo 53 | Seeking DR or DG solutions to alleviate loading on Station 53 | Failed to pass BCA | 2020 |
| | Brooklea Dr - Fayetteville | Relief needed for overloaded step-down ratio transformer | Failed to pass BCA | 2020 |
| | Pine Grove Substation | 10 MW load relief needed by 2021 | Evaluating relief proposals | 2021 |
| | Golah-Avon | Load relief needed to keep voltage on Golah-N. Lakeville lines 216 & 217 within allowed range | Evaluating relief proposals | 2021 |
| | Watertown New 115/13.2 kV Substation | Relief for substation MWh violation and two feeders approaching thermal limits | Evaluating relief proposals | 2022 |
| | LHH – Mallory 34.5 kV 22 Line Reg | Low voltage management on sub-transmission line | Solicitation closed | 2022 |
| | Old Forge | Relief needed for summer loading and reliability problems | Evaluating relief proposals | 2023 |
| | Gillbert Mills | Relief needed for overloaded substation at Gilbert Mills for reliability – 1.7MVA load at risk | Evaluating relief proposals | 2023 |
| | Baldwinsville | Relief needed for two overloaded substations and five to six overloaded distribution feeders | Failed to pass BCA | 2023 |
| | Byron F1863 – Rebuild/Reconductor | Improve tie capabilities with neighboring feeder by increasing capacity of existing feeder | Solicitation closed | 2025 |
| | Sonora Way Feeder | Defer feed construction for new load service | Solicitation recently closed | N/A |

| | | | | |
|---|---|---|---|---|
| **NYSEG[6]** | Java Substation | Defer transformer replacement for overloaded distribution substation | Final Evaluation/Contract Negotiation | 2019 |
| | New Gardenville Substation | Defer installation of additional transformer for voltage management | Evaluating relief proposals | 2021 |
| | Stillwater Substation | Defer upgrade of two miles of distribution circuit to 12.5 kV and installation of additional transformer | Final Evaluation/Contract Negotiation | 2022 |
| | Hilldale Substation | Defer conversion of 4.8 kV circuit to 12 kV circuit and addition of new 12.5 kV feeder | Solicitation underway | |
| | Orchard Park Substation | Defer upgrade of transformer bank and conversion of three distribution feeders | Solicitation underway | |
| **Orange & Rockland[7]** | Monsey | Relief of 0.5 MW by 2019 and ~3 MW by 2021 needed to defer substation and circuit upgrades | Siting and contracting | 2021 |
| | Pomona | 1.2 MW load reduction needed to satisfy circuit contingencies | Awaiting planning board approval and contracting | 2021 |
| | West Haverstraw Area – Distribution Circuit Relief | Reduce loading on three circuits by procuring 5 MW capacity reduction | Solicitation closed | 2021 |
| | Blooming Grove | 15.5 MW capacity reduction needed to improve reliability | Solicitation closed | 2021 |
| | Sterling Forest 67-1-13 (Tuxedo Park) | Defer installation of 13.2 kV tie line by procuring 746 kW capacity reductions | Solicitation underway | 2021 |
| | West Warwick | 7 MW of capacity reduction needed for load relief and reliability | Solicitation recently closed | 2022 |
| | Mountain Lodge Park | Defer installation of 13.2 kV tie line by reducing peak demand by 280 kW | Solicitation recently closed | 2022 |
| **RG&E[8]** | Station 51 Transformer | Defer need for substation upgrade in distribution area north of Rochester | Evaluating relief proposals | 2020 |
| | Station 46 | Defer need for transformer bank replacement in urban part of Rochester | Proceeded with wires solution | |

[1] REV CONNECT. Non-Wires Alternatives. https://nyrevconnect.com/non-wires-alternatives/.
[2] Central Hudson. https://www.cenhud.com/workingwithus/non-wires-alternative-opportunities.
[3] Consolidated Edison. Non-Wires Solutions. https://www.coned.com/en/business-partners/business-opportunities/non-wires-solutions.
[4] National Grid Non-Wires Opportunities. https://ngrid.apps.esri.com/NGSysDataPortal/NY/index.html.
[5] National Grid Potential NWA Opportunities in New York. https://ngus.force.com/servlet/servlet.FileDownload?file=0150W00000ETBgD.
[6] NYSEG. Non-Wires Alternatives. http://www.nyseg.com/SuppliersAndPartners/NonWiresAlternatives/ProjectOpportunities.html.
[7] Orange & Rockland. Non-Wires Alternatives. http://www.oru.com/nonwires.
[8] RG&E. Non-Wires Alternatives. http://rge.com/SuppliersAndPartners/NonWiresAlternatives/ProjectOpportunities.html.