Guidance on DER as Non-Wires Alternatives (NWAs)

Technical and Economic Considerations for Assessing NWA Projects

3002013327

Guidance on DER as Non-Wires Alternatives (NWAs)

Technical and Economic Considerations for Assessing NWA Projects

3002013327

Technical Update, December 2018

EPRI Project Managers

N. Enbar
J. Taylor

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The Electric Power Research Institute (EPRI) prepared this report.

Principal Investigators
S. Coley
N. Enbar
A. O’Connell
J. Taylor

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Guidance on DER as Non-Wires Alternatives (NWAs): Technical and Economic Considerations for Assessing NWA Projects. EPRI, Palo Alto, CA: 2018. 3002013327.

ABSTRACT

Non-conventional solutions to anticipated distribution constraints are increasingly being considered by utilities due largely to the proliferation of distributed energy resources (DER), falling DER technology costs, and supportive regulatory directives. Although these non-wires alternatives (NWAs) present interesting opportunities for distribution planners, they also pose certain challenges given uncertainties around resource output, reliability, and cost. This report outlines key factors to consider when evaluating the merits of an NWA project and offers insight from real-world initiatives to further inform associated utility strategies.

The key considerations presented in the report are organized into four thematic categories:

- **Locational considerations.** Those involving spatial and siting limitations, the location of the constraint, and feeder siting.
- **Temporal considerations.** Those concerning resource availability, output variability, sustainability of response, and resource lifetime.
- **Additional design considerations.** Those encompassing the sizing of NWAs, alternative lead times, reliability, customer participation, and third-party contractual arrangements.
- **Economic considerations.** Those regarding the costs and benefits of NWA projects given DER performance and lifetime considerations in the context of the regulatory/policy landscape.

The considerations within each category, along with their impacts on the distribution planning process, are initially discussed. Subsequently, three NWA projects are profiled—two existing, one proposed—to highlight the locational, temporal, design, and economic rationales informing their structural development. Taken together, the key considerations and case study examples are intended to help guide utility thinking around successful NWA strategies for meeting short- and long-term grid planning and management objectives.

Keywords
Arizona Public Service Punkin Center
Brooklyn Queens Demand Management (BQDM)
Distributed energy resources (DER)
Distribution planning
Non-wires alternatives (NWAs)

Deliverable Number: 3002013327

Product Type: Technical Update

Product Title: Guidance on DER as Non-Wires Alternatives (NWAs): Technical and Economic Considerations for Assessing NWA Projects

---

PRIMARY AUDIENCE: Utility distribution system planners

SECONDARY AUDIENCE: Other utility staff and researchers involved in distributed energy resources (DER) integration

KEY RESEARCH QUESTIONS

How should non-wires alternatives (NWAs) be considered, both technically and economically, as part of the distribution planning process? What real-world approaches can help inform future utility NWA strategies?

RESEARCH OVERVIEW

Key factors to consider when evaluating the merits of an NWA project are initially categorized and discussed; these include locational, temporal, design, and economic considerations. Three real-world NWA case studies—two existing, one proposed—are next presented to highlight how several of the previously described key considerations informed the projects' structural development. Findings are intended to help guide utility thinking around successful NWA strategies for meeting short- and long-term grid planning and management objectives.

KEY FINDINGS

- Utilities must have visibility, control, and site guidance of DER for these resources to be integrated into the system as an NWA.
- Given the relative immaturity of DER (that is, their limited field deployment), much is still to be learned about their ability to both technically and economically meet NWA objectives.
- Although additional considerations must be made for DER to be recognized as an NWA, the general steps of the planning process—1) identify expected system constraints, 2) assess potential resource availability, 3) design a set of mitigation alternatives, and 4) alternative evaluation and selection—do not need to change.
- An emerging subset of NWA projects is departing from historical approaches that exclusively apply demand-side management schemes (for example, energy efficiency and demand response measures) and is instead employing energy-exporting resources—such as solar photovoltaics (PV), fuel cells, combined heat and power (CHP), wind, and energy storage—to achieve both short- and long-term goals.
- NWA initiatives often serve as a testing ground for technology applications, use cases, and business model proofs of concept. To date, their justification is often tied to regulatory policies. Meanwhile, project economics tend to be context-specific.

.

- Example NWA projects often include risk mitigation strategies and contingency plans to ensure reliability. This could include features such as modular sizing to adjust for future growth, using portfolios of DER with different locational and temporal characteristics, redundancy in communications infrastructure to ensure constant connection with DER systems, or on-call contingency generators in the event of a battery outage.
- Recognizing non-traditional (and non-distribution) related value streams from DER—such as avoided energy costs and voltage regulation—and/or taking advantage of supportive regulatory cost recovery rules may be key to meeting economic thresholds and, in turn, greenlighting NWA projects.

WHY THIS MATTERS

Non-wires alternatives are becoming more prevalent. Their characteristics and impacts need to be better understood to effectively integrate them into the distribution planning process, inform their strategic evaluation, and comply with emerging regulatory and policy directives.

HOW TO APPLY RESULTS

Considerations and guidance can be incorporated into utilities' distribution planning processes and practices. Learnings can be taken from the existing and proposed projects outlined in the case studies.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- The report *Incorporating DER into Distribution Planning* (3002010997) is a prerequisite to this report.
- A parallel research effort undertaken in 2018 examined how to determine the impacts of groups of DER on distribution systems from the perspective of hosting capacity. Findings are available in the report *Examining the Technical Distribution System Impacts of Mixed DER Groups* (3002013373).
- Future work in 2019 will include the development of automated methodologies for identifying and evaluating both traditional and non-wires alternatives.

EPRI CONTACTS: Nadav Enbar, Principal Project Manager, nenbar@epri.com; Jason Taylor, Principal Project Manager, jtaylor@epri.com

PROGRAMS: Integration of Distributed Energy Resources, P174; Distribution Operations and Planning, P200

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION

Characterizing the Existing Planning Process

Planning for the future electricity system is a critical task that every electric utility must undertake to ensure that a safe and reliable supply is maintained for all customers. However, at the distribution level this task is becoming increasingly complex due to the emergence of distributed energy resources (DERs) and evolving load.

While distribution planning is a process that can vary among utilities, it usually follows the same general steps shown in Figure 1-1. The first step of the process is to identify the expected system constraints that will impact a utility's ability to reliably service its customers. This is typically accomplished by performing a study that incorporates forecasted growth and system changes to determine when and where constraints are likely to arise. Constraints on the as built system could occur due to geographical expansion into new developments or from changes in load on the existing system. When constraints are recognized, resources suitable for mitigating the issue are then identified. Traditionally, these "resources" are system asset upgrades, new construction, or system changes, such as the transfer of loads between feeders.

Once the potential options have been identified, a suite of alternatives can then be designed to meet the specific need. Finally, once the set of alternatives has been identified and designed, each one can then be evaluated and the best option selected for implementation based on the needs and objectives of the system. Typically, the least cost alternative is chosen, but other criteria – such as reliability – can also be considered.

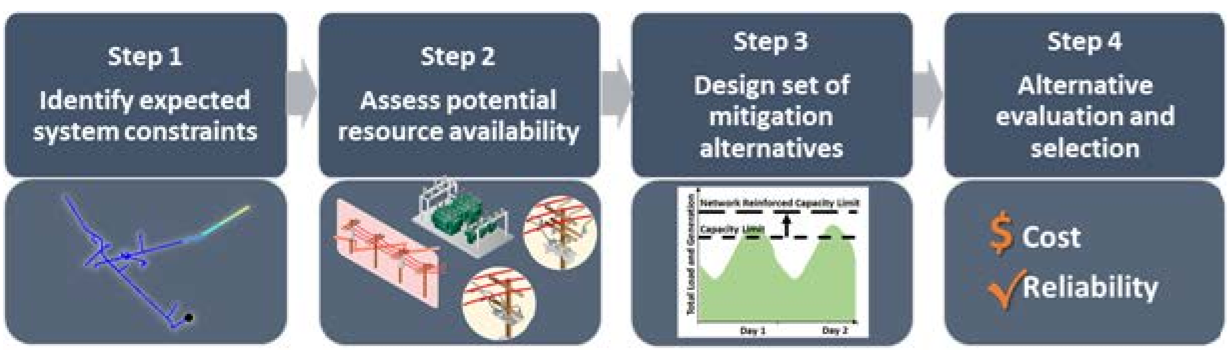

Figure 1-1
Distribution planning process steps

DER Accommodation versus Integration

The grid connection of distributed energy resources is becoming more common. Photovoltaics (PV), battery storage, electric vehicles, and various other technologies are emerging at the distribution level in different capacities. This presents both new challenges as well as the opportunity for innovative solutions from a distribution planning perspective. DERs can be viewed from two overarching perspectives, depending on their characteristics and the driver(s) for their grid connection:

1. as resources that may require mitigation and need to be accommodated at the distribution level, or

2. as resources that can be integrated into the distribution system as alternative solutions to traditional distribution upgrades.

Not all DERs will fall cleanly into one category or the other, however. From a distribution planning standpoint there is a spectrum between fully accommodating and fully integrating DERs, as shown in Figure 1-2. The influence that the utility has on site guidance, control, and visibility of a particular resource determines where on the spectrum that resource will lie. Organically growing customer-driven PV, for example, which the utility has no visibility or control of, would lie on the accommodating end of the spectrum shown by the red arrow. A utility-owned combined heat and power (CHP) plant that is installed and controlled by the utility would, meanwhile, lie on the integrating end of the spectrum, as shown by the blue arrow. A distribution connected storage system that has a primary service to provide frequency response for the transmission system, but that the distribution utility has visibility of, would need to be accommodated at the distribution level. But the distribution utility having visibility means that the resource would lie slightly towards the integration end of the spectrum, where the yellow arrow is located.

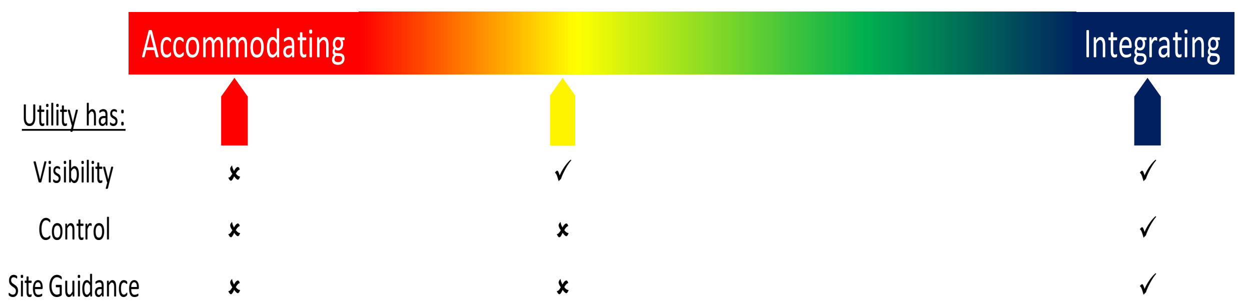

Figure 1-2
Spectrum between integrating and accommodating DER

Regardless of whether DERs are being accommodated or integrated, they must be included in the overall distribution planning process. The high-level steps outlined in Figure 1-1 do not need to change, but consideration must be given to how DERs will modify specific parts of each step. This topic is discussed in further detail in [1].

Non-Wires Alternatives

A non-wires alternative is defined as a utility-driven solution to an identified distribution constraint that defers or eliminates the need for a traditional distribution upgrade.

Non-wires alternatives (NWAs) are resources that fall towards the integrating end of the spectrum in Figure 1-2. In the NWA definition shown in the blue call-out box at right, traditional distribution upgrades are classed as mitigation alternatives that are currently used by distribution planners (e.g. reconductoring, substation upgrade, capacitor/regulator additions, load transfer, etc.). NWAs, meanwhile, could comprise PV, wind, storage, fuels cells, as well as demand response (DR) schemes and energy efficiency (EE) measures. The distribution constraint may arise as a result of increasing load or a desire to facilitate more distributed generation, depending on anticipated growth and the requirements of the distribution planner. A critical aspect of an NWA, however, is that the solution is driven by the utility and its obligation to serve its customers. DER may appear organically and offset the need for a traditional upgrade, but this should be regarded in the same way as lower than anticipated growth — a change in the plan rather than an NWA, as the utility does not have a need for that DER to serve its customers reliably. It is also important to note that although NWAs are applicable at all levels of the power system, a resource that is employed as an NWA for the transmission system may not provide relief for distribution constraints.

Although most NWAs will lie firmly on the integrating end of the spectrum in Figure 1-2, longer-term planning will allow some resources which fall closer to the accommodating side to also be considered as NWAs. Schemes such as energy efficiency, demand response, incentives, and time of use tariffs, while driven by the utility for the purposes of deferring upgrades, likely do not have the same level of utility site-guidance as other resources. These types of resources can still be thought of as NWAs, but only in the context of a long-term planning horizon for resolving wider scale constraints rather than a short-term horizon focused on localized constraints.

NWAs can be applied to resolve a range of distribution constraints, and just like traditional solutions, certain resources will be more suitable for resolving specific constraints than others. Table 1-1 shows the applicability of various resources for resolving feeder constraints, both for grid-side and NWA solutions. There is more certainty with grid-side alternatives: the solution either is or is not able to resolve an issue. For NWAs, dispatchable resources should be able to resolve any issues, however the suitability of non-dispatchable and variable resources for constraint relief are less clear-cut. Non-dispatchable and variable resources may be able to resolve thermal and voltage constraints, but further consideration of their technical capabilities is needed. These considerations are discussed in detail in Chapter 2.

Table 1-1
Suitability of different alternatives for relieving key feeder constraints

Alternative Type		Capacity for Additional Load	Capacity for Additional Generation	Over-Voltage	Under-Voltage
Grid-Side	Reconfiguration	●	●	●	●
	Reconductoring	●	●	●	●
	Transformer upgrade	●	●	●	●
	Voltage uprating	●	●	●	●
	Voltage regulator	○	○	●	●
	Capacitors	○	○	○	●
	Voltage control settings	○	○	●	●
NWA	Dispatchable resource	●	●	●	●
	Non-dispatchable resource	◒	◒	◒	◒
	Variable resource	◒	◒	◒	◒

● Yes ◒ Maybe ○ No

Beyond relieving distribution constraints, NWAs can provide additional benefits to utilities and power systems that conventional distribution system solutions cannot. Outside of the times that the resource is being utilized for its primary distribution objective, certain types of NWAs have the potential to provide ancillary services to the bulk system and participate in markets. For example, energy storage can be used for energy arbitrage or voltage regulation among other "value stack" services. Energy efficiency measures or combined heat and power can reduce baseload energy needs outside of peak times. Furthermore, in applicable situations, renewable NWAs can contribute to mandated renewable portfolio standards and/or offset carbon taxes.

2
CONSIDERATIONS FOR NON-WIRES ALTERNATIVES

Distributed energy resources present a unique opportunity for distribution planners to provide innovative and potentially more tailored alternatives to traditional distribution upgrades. However, NWAs may not be directly comparable to traditional solutions, and will likely require additional technical and economic considerations to ensure that reliability of service is maintained. These considerations can be split into four categories:

- *Locational considerations*: Those involving spatial and siting limitations, the location of the constraint, and feeder siting.
- *Temporal considerations*: Those concerning resource availability[1], output variability, sustainability of response, and resource lifetime.
- *Additional design considerations*: Those encompassing the sizing of NWAs, alternative lead-times, reliability, customer participation, and third-party contractual arrangements.
- *Economic considerations*: Those regarding the costs and benefits associated with pursuing NWA projects given DER performance and lifetime considerations in the context of the regulatory/policy landscape.

Locational Considerations

The location of a specific distribution issue will impact the resources that are available to resolve that issue. When considering an NWA, it is therefore important to make a number of geographical- and locational-based considerations regarding spatial requirements and feeder siting.

Spatial and Siting Limitations

Spatial requirements can be both a limiting factor and a benefit for NWAs. For certain types of DERs, such as wind or large-scale PV, large areas of land are required. This means that if the need for relief arises in a highly populated urban area – which is often the case due to the correlation between population and electricity demand – these resources would not be suitable mitigation solutions.

Traditional solutions can suffer a similar fate in situations where there is limited physical space for upgrading a transformer or installing a regulator. In these instances, certain types of DER can be more appropriate solutions. Demand response, for example, is an NWA that does not have any spatial requirements and thus may be a suitable alternative to a transformer upgrade if the existing transformer is only overloaded at certain peak load times. The Brooklyn Queens Demand Management (BQDM) project, described further in Chapter 3, is another example. In

---

[1] The ability of DER to be available when needed could be defined as 1) an instant in time (i.e. time of day), 2) a duration of time (seconds vs. hours), 3) a certain frequency (i.e. once per hour vs. once per year), or 4) length of planning horizon (i.e. short- or long-term solutions).

this case, the traditional solution of expanding or installing an additional substation would have been extremely costly given the value of land within New York City. Instead, a portfolio of energy efficiency and DER solutions were deployed as part of the BQDM initiative that did not incur the same limitation.

Separately, suitable resources may exist in terms of their availability and spatial requirements, but that may be limited geographically on some external basis. Land use or planning permission is one example of this; certain sites may be restricted in the way that land can be used, there may be protections around nature and wildlife, land may be zoned for specific purposes such as housing, or land owners may be unwilling to sell a particular site. Another example is safety and access restrictions; potential NWA locations might not be easily accessible by fire departments, may obstruct access to other locations, or weaken structures and prove dangerous in the case of a fire.

Location of the Constraint on the Electrical System

Depending on the issue that arises as part of the planning study, the resources being employed for mitigation will likely need to be installed at a particular location on a distribution feeder for maximum effectiveness. If thermal constraints are the predominant issue, the NWA will need to be located downstream of the affected element. If voltage violations need to be relieved, resources are best located as close as possible to the electrical bus with the violation.

Additionally, considerations about the characteristics of the circuit itself and how it is operated need to be made. One of the most important of these considerations is hosting capacity. When installing a particular resource to mitigate a constraint, care needs to be taken to ensure that the NWA itself will not cause problems at other times. For example, if a planning study identifies that a line on a feeder will become overloaded during peak load times, and a PV system is deployed in order to resolve that overload, it is important to examine whether that PV system in that location could cause overloads or overvoltages during minimum loading conditions. This can be achieved by performing a hosting capacity analysis.

Another consideration that must be made regarding location on a circuit is the switching or reconfiguration possibilities of radial systems. Many utilities employ feeder switching to meet growth, for maintenance, or as part of their day-to-day operations. However, this switching may reduce or negate the effectiveness of an NWA. A resource that was downstream of a constrained asset may not be there to provide relief after a reconfiguration.

This is illustrated by the simple example given in Figure 2-1, which shows two substations with a feeder in between that can be reconfigured by opening/closing the two connecting switches. In Configuration 1, an NWA is installed at Bus C to mitigate the transformer overload. If, however, the circuit needs to be reconfigured to Configuration 2, the NWA at Bus C is now connected to the neighboring transformer and not the overloaded one, meaning that relief is no longer available for the overloaded transformer. This is an illustrative example, but in reality configurations may be much more complex, particularly in meshed systems. Therefore, detailed analysis may be required to ensure resources are located where and when they are needed.

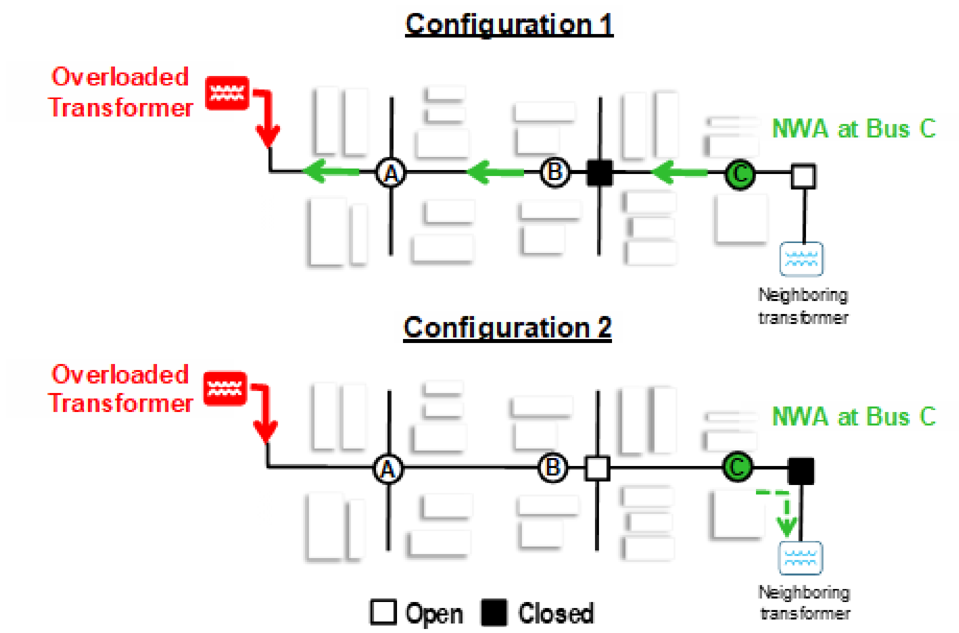

Figure 2-1
Example of reconfiguration impact on NWA effectiveness

Networked or meshed systems can add an additional layer of complexity. Unlike radial systems, networked systems are characterized by complex and multidirectional power flows, so the effect of DERs located electrically "close" to a violation may become dispersed. In some cases, dispersion is so significant that the DERs may only deliver a fraction of their nameplate capacity toward mitigating a violation. Hence, for systems with significant meshing, potential NWAs may need to be oversized to provide the necessary relief.

Temporal Considerations

Each type of DER has its own temporal characteristics that must be taken into account when planning an NWA. If a resource is available, the specific resource characteristics, combined with the characteristics of the distribution issue, will define whether that resource is suitable for mitigating the issue, and how the resource will compare to a traditional solution in a number of key aspects.

Resource Availability

Linking back to the locational considerations previously discussed, the geographical area or region under study will inherently limit the types of resources that can be considered as part of an NWA. Depending on the climate, weather, terrain and other factors, certain types of fuel sources, and thus DER, may not be available in a sufficient capacity to effectively resolve the local issue. The suitability of PV as an NWA, for example, is dependent on the amount of irradiance an area receives (see Figure 2-2). This value will vary day to day and season to season, so aligning expected irradiance during the constraining time period is important.

Average seasonal wind speeds and altitude are significant determinants of wind energy's suitability as an NWA. At higher altitudes wind speeds tend to be greater, however at too high an altitude access would likely be an issue for installation and maintenance. Although fuel cells do rely on the availability of a fuel source, that fuel source (e.g. natural gas or methanol) can be very flexible. Similarly, storage does not depend on the availability of a particular fuel so is suitable for most areas. Other types of NWAs, such as demand response or energy efficiency programs, while not fuel dependent, do rely on a type of resource in the form of flexible load and consumer participation. These resources necessitate different considerations, such as the load composition and type of customers in an area, as well as their willingness to participate in particular programs and the incentives that may need to exist to achieve that participation.

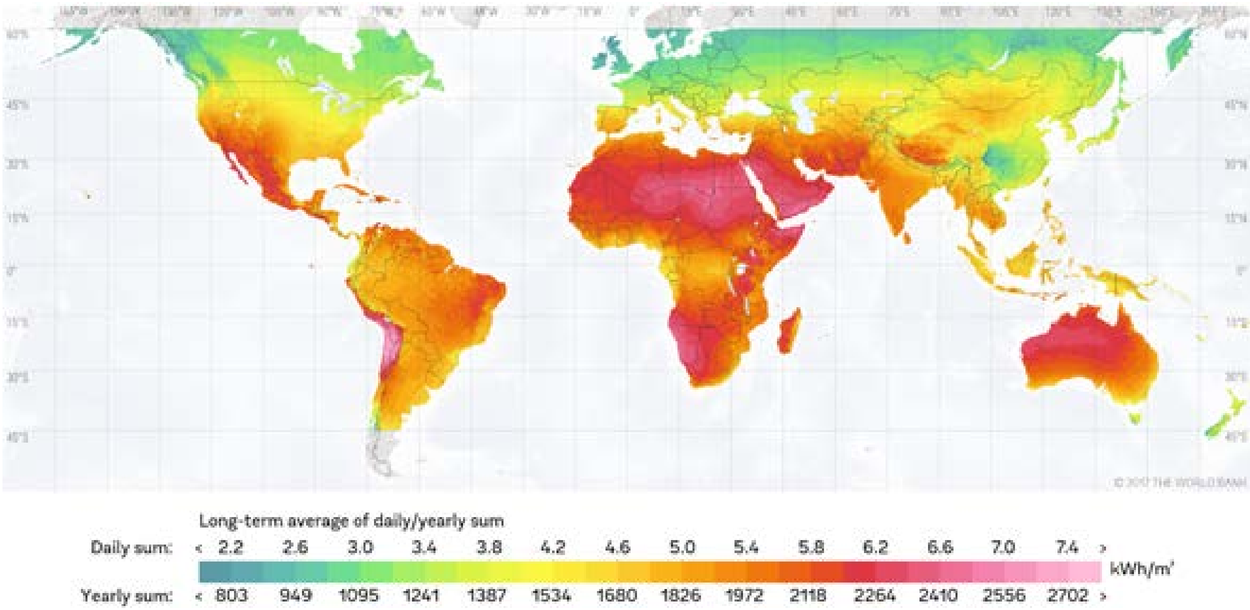

Figure 2-2
Global Horizontal Irradiation

Source: Solar resource data obtained from the Global Solar Atlas, owned by the World Bank Group and provided by Solargis (http://globalsolaratlas.info)

Output Variability and Temporal Behavior

Because many DERs rely on some type of fuel source to be available, or on external factors to achieve results, one of the biggest concerns that emerges when considering an NWA is whether the resource will be available to provide support when it is needed. This is dependent on the variability of the resource output, which differs greatly among various DER types, and is not something that typically needs consideration for conventional solutions.

Resources that are fueled by renewable sources such as PV and wind tend to be the most variable. The output from PV varies depending on temporal and meteorological factors such as the time of day, season, and weather (primarily cloud coverage). Other relevant factors relate to the PV installation itself, such as capacity, whether it is fixed tilt or has a tracking system, and the inverter specifications. Sunrise and sunset times are known precisely throughout the year, and combined with the system's specifications can provide a forecast of what the ideal output should be. This ideal output provides a window during which PV can potentially be used as an NWA. It is therefore important to consider the temporal aspect when performing the initial planning study.

Even though the ideal PV system output can be determined relatively easily, significant fluctuations from that output are likely due to weather changes. Temperature can affect PV system production, as PV arrays become less efficient at high temperatures. The factor that contributes most to PV's variability is, however, cloud coverage. A change in cloud cover can cause PV power output to rapidly drop from 100% to 0% or vice versa. Furthermore, the same level of peak demand could occur on a clear sunny day as a cloudy humid day due to air conditioning load, and although PV could relieve constraints associated with the former, it may not with the latter.

Figure 2-3 shows a box-and-whisker plot of PV output in July for eight PV systems in a sunny region over four years. The plot conveys the PV output minimum and maximums (end of whiskers), as well as the median (the line in the box) and quartile values (top and bottom of the box) recorded for each hour of the day in July. The simple takeaway: PV output can vary even in a sunny region for the best month of the year.

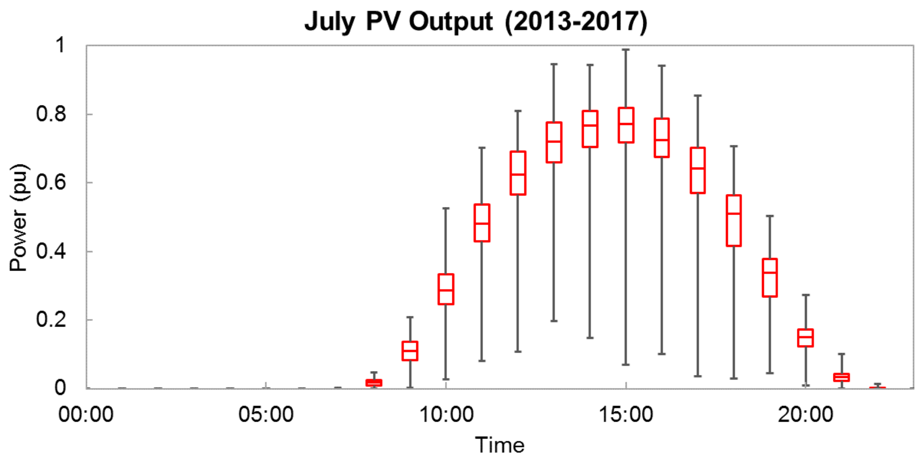

Figure 2-3
Box and whisker plot of 4 years of hourly PV output in July for a sunny region

Wind presents similar challenges, and can in fact be more variable than PV. Like PV, multiple factors related to the wind turbines themselves impact system output, such as capacity, hub height, and blade length. Wind speed is, however, the most variable determinant of output. Wind is a resource that can change seasonally, daily, hourly and even sub-hourly. Some notable trends have emerged, but are localized and not guaranteed: 1) wind speeds tend to be higher in winter and lower in summer, and 2) in certain areas wind can peak in the morning. Due to the fact that wind cannot be relied upon to be available when needed, it is typically not a feasible NWA on its own.

The output variability of EE and DR depends primarily on the load composition and consumer participation. Customer participation has a more significant effect on the total capacity of these resources and will be discussed in further detail later below. The load composition is a factor that is more likely to impact the output variation of such resources. EE programs, for example, usually target specific inefficient technologies that can be upgraded, such as incandescent lighting or hot water heaters; therefore, typical profiles for these specific devices need to be analyzed to determine how the response will affect the overall load profile at certain times of day and year. For instance, more efficient water heaters would reduce consumption in the morning and evening, improvements to lighting efficiency would have a more consistent reduction throughout the day and an increased reduction in winter versus summer. For DR, the primary concern is usually the load composition during peak load times. The appliances being utilized during that time will determine the potential response that can be achieved. The utility will also typically send a signal during these times to trigger DR, therefore there is a degree of dispatchability around the output from DR, although the level of response, as with EE, will depend on customer uptake.

Resources such as fuel cells or CHP plants tend to have a more reliable output since their fuel source can be stored onsite to provide greater availability. Battery storage, although more limited in terms of their energy output than fuel-based resources, is a dispatchable resource. System production will vary throughout the day, however it is often controlled by the utility to achieve a specific objective. Therefore, once the control logic has been planned and implemented correctly to provide temporal adequacy, storage should provide a reliable output.

Of note, although the output of individual resources may be too variable to rely on for grid support, diverse portfolios of DER can often provide more reliability, flexibility and controllability than a single resource. In particular, pairing storage with more variable resources, such as wind or PV, can offset some of the fluctuations that can occur, and ensure that output is available when the variable resource is not producing. Similarly, having a large number of smaller resources can provide a greater degree of reliability than relying solely on a single large unit. Portfolio design is discussed in further detail later in the report.

Sustainability of Response

Related to output variability, sustainability of output can be another important consideration for NWAs. With most traditional mitigation alternatives, sustainability does not have to be considered, since equipment such as conductors or capacitors are not reliant on a specific resource being available and are not energy limited. However, a distribution constraint may last for a sustained period of time, and if an NWA solution is being deployed it must be able to provide support for the full duration of the constraint. For renewable resources like PV and wind, sustainability is not guaranteed due to the output variability described in the previous section, although probability assessments can be employed to statistically describe the sustainability of the resource. EE measures may be able to reduce demand for extended periods of time depending on the targeted appliances and their typical duration. Ideally, DR should be able to sustain a response for as long as the price signal dictates. However, in reality, there is a limit to how long consumers are willing to offset their usage. They may be happy to delay their shower for two hours but not four, for example.

Storage systems are energy limited, meaning that they can only provide a response for as long as they've been designed to do so. They also need the time to both charge and discharge, so the time required to get the storage to the state of charge that is needed to relieve the distribution issue is another important consideration. As such, the duration and temporal aspects of the distribution constraint are key when considering storage as an NWA. The power and energy ratings of a storage device must be designed to meet the maximum power and total energy required by the constraint, and also be able to collect or deplete the energy required by the constraint outside of the constraint window, without causing additional distribution issues. The grey area in Figure 2-4 shows the storage energy requirement for discharging to ensure that demand does not exceed the given limit in red. However, the total area in green that is available for recharging is less than the grey area, so if the battery was sized based only on the grey area, it would not have enough time to recharge fully to relieve the distribution constraint. Further discussions regarding sizing of NWAs is discussed later.

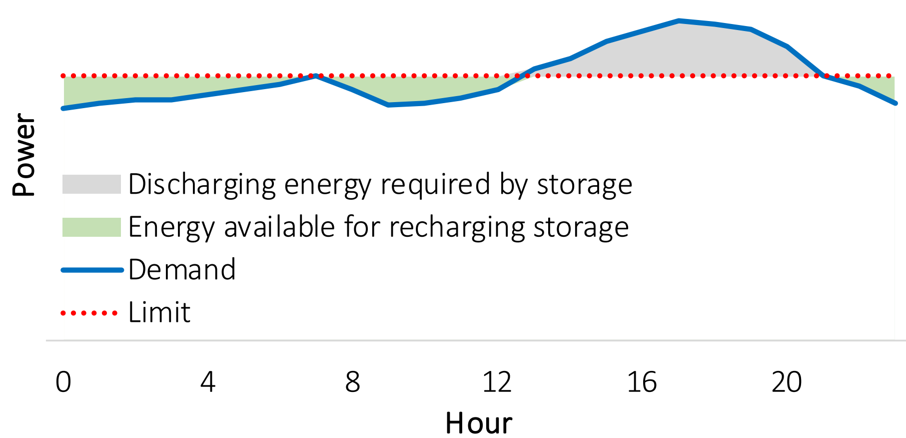

Figure 2-4
Example of energy consideration for storage as NWA

Resource Lifetime (Planning Horizon)

Traditional distribution assets have been widely used for many years. As such, there is a wealth of experience regarding their typical lifetimes. Conversely, a lot of DER technologies are relatively new, and have not accrued the same level of field experience to assess their long-term performance. Furthermore, many DER technologies are composed of a number of different components, including individual modules, inverters, and communications devices, each of which has its own lifetime and will contribute to the overall expected life of the NWA.

Of the renewables-based technologies, wind turbines have had the most significant opportunity for field testing, with some of the earliest installed turbines now coming close to the end of their design lifetimes – typically 20 years. Some turbines operate beyond typical turbine design lifetimes, however, and in these cases, it is important to reassess the remaining useful lifetime of the asset so that it can be decommissioned before complete structural failure. In the coming years, more turbines will surpass their 20-year design lifetime and more data will become available, which will be valuable in assessing whether longer typical lifetimes for turbines are feasible.

PV has had fewer years of field testing than wind, in most cases less than ten years, therefore some assumptions have had to be made about PV lifetime based on modelling and simulation. Average design life for PV modules is in the range of 20-25 years, with output degradation rates typically ranging from 0.7-1.5% per year depending on the technology [2]. These can vary significantly, however, due to stresses caused by localized weather and climate conditions, such as extreme temperatures or storms, as well as manufacturing and installation oversights.

Field experiences with the lifetime of energy storage are few and far between, as the technology is still at an early stage. For batteries, it is not just the number of years that determines lifetime, but a combination of time and charge/discharge cycles. The asset will age over time depending on material used, local conditions, among other things, but cycling accounts for the majority of degradation. As such, most vendors will list number of cycles as the lifetime metric. Typically, these fall in the 1000-5000 cycles at 80% depth of discharge [3].

PV inverter lifetimes (~15 years) tend to be 5-10 years shorter than module lifetimes, and thus must be replaced during a PV system's lifetime. Although additional industry analysis is needed, inverter lifetimes may also be shorter than expected energy storage system lifetimes.

NWAs that are third-party owned or operated require additional considerations in terms of lifetime. If a utility is depending on a third-party asset to be available long term and a company goes out of business, or EE or DR customers move or decide they no longer want to participate in a program, that resource is no longer available. Although these types of arrangements may have contracts in place, the long-term availability of the resource is inherently uncertain. It is important for a utility to be aware of this additional risk when considering these types of resources as NWAs.

A key takeaway, particularly in terms of DER lifetimes, is that a lot is still largely unknown. In the coming years it will be of utmost importance to gather the data and learnings from deployments currently in the field, as these will help inform considerations for using DERs as non-wires alternatives.

Additional Design Considerations

Sizing

The size of any mitigation measure will be dictated by the severity of the distribution issue. If the distribution issue is a thermal one, the size of the overload will determine the capacity needed for a solution. Similarly, if voltage is the primary constraint, the extent to which the voltage exceeds normal limits will define the size of the solution. With conventional solutions, these are typically the only parameters needed to determine size; for NWAs, however, additional considerations need to be made, which relate back to the earlier discussion around variability and sustainability of NWAs.

In terms of variability, the timing of the constraint must be compared with the typical output of the resource at that time. If the resource is not expected to provide its maximum output when the constraint occurs, then the size of the resource will need to be scaled up. For example, if an overload of 1 MW occurs at 3pm, and expected PV output at 3pm is 0.7 pu, then the size of a PV system required to resolve the 1-MW overload is 1.43 MW. Determining the expected output of variable DER can often present a significant challenge, as the range in output at the time a constraint occurs may be considerable, as was highlighted in Figure 2-3. Taking a conservative approach and assuming an output on the low side of the range may mean the size of the resource is unreasonably large. Conversely, assuming an output at the high side of the range poses risk in terms of the resource being available when needed. Probabilistic approaches can be employed to determine likely outputs for DER, as well as how the output aligns with the need. Furthermore, diversifying an NWA with multiple DER types can provide increased output reliability.

Certain resources require both a power as well as an energy size to be specified. This relates back to the sustainability of the response discussed in the temporal considerations section. If a constraint is prolonged, or arises repeatedly, ensuring the NWA is sized appropriately to provide a sustained response is critical. In order to determine the required energy size, the sum of the energy required by the constraint over the duration of the constraint should be calculated. For resources like storage, which also require time to charge/discharge to mitigate a constraint, care should be given to ensure that the time available outside the constraint window is enough to re-charge/discharge, as necessary; otherwise, the energy size will need to be increased accordingly.

Location also plays into the sizing of an NWA. The distributed nature of certain resources, such as demand response, means that sizing the resource based on the size of the constraint will likely not be sufficient. The potential losses that would be incurred by transferring the power should also be taken into account, which will result in an increase in the size of the NWA. Moreover, if the system experiencing a constraint is meshed rather than radial, the dispersed nature of the power flows will necessitate a larger NWA size.

Sizes of traditional assets usually increment in steps, therefore the size of the asset chosen typically reflects the size of the constraint plus a degree of headroom. For example, if a 2 MVA transformer is predicted to be overloaded by 0.2 MVA, the next available size for a replacement transformer could be 2.5 MVA, giving an additional 0.3 MVA of headroom. Further, it may be a prudent practice to standardize upgrade designs and sizes to reduce costs. This may add headroom if the prudent upgrade incorporates a larger incremental step size due to the implementation of the standard design rather than customized smaller incremental step. This additional headroom may be beneficial if actual growth exceeds forecasted growth. As sizes of DER tend to be more granular than conventional solutions, it is unlikely that an NWA will provide headroom unless designed to do so. This is yet another consideration that should be made when sizing an NWA.

Lead-time

The initial planning study will determine a future point in time by which a constraint is anticipated to arise and a solution is needed. This will inform the available timeframe for identifying, procuring, and deploying a potential alternative. The lead-time for alternative projects can vary significantly, depending on the scale of the required project. Constraints that are expected in the short-term may not be resolved by a solution that requires longer construction or installation lead-times. For example, programs or schemes that require third party participation will likely have a longer lead time and be unsuitable for short-term planning needs.

Traditional upgrades are typically designed and implemented by the utility in-house, therefore the lead-time for these types of projects depends primarily on the installation time of the project. For an NWA, there is usually a significant amount of time required for solution procurement and deployment [4], which can add a degree of uncertainty to the overall lead-time of the project. Once a utility decides that an NWA is a feasible solution to the distribution constraint, a request for proposals is typically issued. A sufficient window of time must be allowed for bids to be prepared and submitted. Once that window has closed, the bids must be assessed and a winning bid selected before the deployment of the solution can begin. This process can take a significant amount of time, and if the need is pressing, there may not be time to go through it. Furthermore, if none of the submitted bids meet all of the NWA requirements, then considerable time has been wasted that could have been better used developing a wires alternative.

The identified timing of the projected need is another issue to consider regarding alternative lead-times. Due to inherent forecast uncertainties, long-term planning horizons needs are more volatile or uncertain compared to identified near-term needs. As such, potential DER-based alternatives with long lead times aligned with identified long-term needs may be provided a lower valuation or prioritization, as discussed in [4]. The lower prioritization reflects the desire to minimize the deployment of alternatives that prove to be unnecessary or less economically beneficial as future needs become more certain. Conversely, DER alternatives with short lead times (e.g. portable utility-owned storage) may offer the ability to better account for planning uncertainties by providing temporary load relief while more cost effective permanent solutions are implemented.

Reliability

As with NWA resource lifetimes, DER equipment reliability and O&M needs are issues that need further testing and data collection before they can be fully quantified. There have, however, been some learnings to date from existing deployments.

In general, wind turbines are expected to be available approximately 95-97% of the time [5], with this value decreasing as the asset ages. The main reason for unscheduled downtime is due to electrical failures, mainly generator issues, followed by drive train failures like gearboxes, and structural failures which are primarily blade related. By comparison, scheduled maintenance such as inspections and site maintenance tends to require much less cost and downtime.

PV O&M trends are moving towards scheduled and conditional-based maintenance such as inspections, panel cleaning, and site management accounting for the majority of maintenance. This should, in turn, reduce the need for corrective/reactive maintenance, such as module repairs, as well as overall PV downtime [6]. O&M requirements for storage have not been well established due to lack of experience, but in general tend to be low; degradation issues tend to be more of a concern than instantaneous failure [7].

All of the aforementioned resources are also power electronics-based; they are therefore reliant not only on the dependability of their own modules, cells, or turbines, but also on the power electronics in the converter/inverter that is used to connect the devices to the grid. After generator failures, converters are the next most responsible component for wind downtime. For PV, inverter maintenance has been noted as the cause for the majority of unscheduled downtime [8].

Additionally, an increasing number of DER technologies are becoming dependent on the use of communications to achieve their objectives. This communication layer provides a degree of flexibility and control to DER solutions, but it also adds another element that demands reliability considerations. Real-time DR is a good example of a resource that relies heavily on communications to achieve a response. If the communications fail, and a signal is not communicated to the resources, then the resource cannot respond as needed. Thus, for resources which require regular updates, it is important that the communications system be monitored closely, and where possible, outfitted with failsafe options to overcome a potential communications issue.

Customer Participation

Per Chapter 1, the definition of an NWA emphasizes that resources that comprise an NWA must be procured by the utility. Therefore, this section does not discuss the adoption of customer PV or storage, as these would be considered organic growth, and should be accounted for in the planning process. Examples of resources that could be used as an NWA that also require customer participation are EE and DR, as well as incentives, which tend to be considered as part of the longer-term planning horizon.

Quantifying the expected uptake from customers for a particular program is critical to determining whether that program would be a suitable resource for deferring a distribution upgrade. To ascertain such information, one option would be to examine existing efforts, both active programs as well as pilot and demonstration projects, and gather data on adoption and participation. This would also provide useful information regarding the effectiveness of different implementation strategies and program designs. A more labor intensive but comprehensive way to determine consumer participation would be to run new pilots or demonstrations. Results from such projects would give a more accurate representation of the likely response from customers within the local area and would also allow various strategies to be tested. A deeper dive into using EE and DR in distribution planning is given in [9] and [10].

There are a number of characteristics related to customer-owned NWAs that can prioritize certain projects over others. The type of customers in the constrained area is one of these characteristics. Typically, if the load is composed of more large-scale customers, such as commercial or industrial customers, the project should have a higher priority than one where the load is composed of more small-scale customers, as fewer customers need to be engaged to relieve a constraint. In terms of number of customers, if the constrained asset serves a high number of customers, there is greater opportunity for participation than if the constrained asset serves a lower number of customers. These prioritization metrics and others are discussed in more detail in [4].

Third-Party Contractual Arrangements

Utilities could elect to contract with energy services companies and third-party providers of non-wires solutions. Understanding if there is a value proposition for deferring grid upgrades with third-party-owned DER instead of utility-owned DER is important. There may be regulatory barriers preventing deployment of third-party-owned NWAs at the distribution level. If third-party solutions are deemed prudent given the regulatory context, developing contractual arrangements that properly address liability challenges (e.g. vendor bankruptcy) and developing specific contingency plans in case NWA fail to deliver value, are relevant considerations.

Economic Considerations

The total cost of an NWA will depend on the technical design requirements given the previously discussed considerations. There are multiple factors that must be considered to yield proper economic comparison between an NWA and a traditional wires solution.

Upfront Capital Cost

The primary cost component is typically the upfront capital cost of the DER technology itself. As is usually the case with new technologies, the capital cost for DER can initially be significantly higher than the traditional upgrade alternative. But as a technology becomes more widely used, competition increases, manufacturing processes improve, and ultimately costs tend to drop over time. This has been the case for PV, with the module price dropping from $85/W in 1976 to $0.23/W in 2018, as illustrated in Figure 2-5. Similarly, wind turbine prices have fallen by 32% since 2010, and lithium-ion battery storage is expected to fall by 66% between 2017 and 2030 [11]. Therefore, when technology costs are being considered, the fact that these costs are likely to be less in the future than they are today should be taken into account. Capital costs for NWAs should include all costs, including integration costs, such as remote monitoring, control, and related infrastructure if it is required. Although schemes such as EE do not require any capital cost in terms of equipment, they may incur an upfront cost or incentive to encourage customer participation.

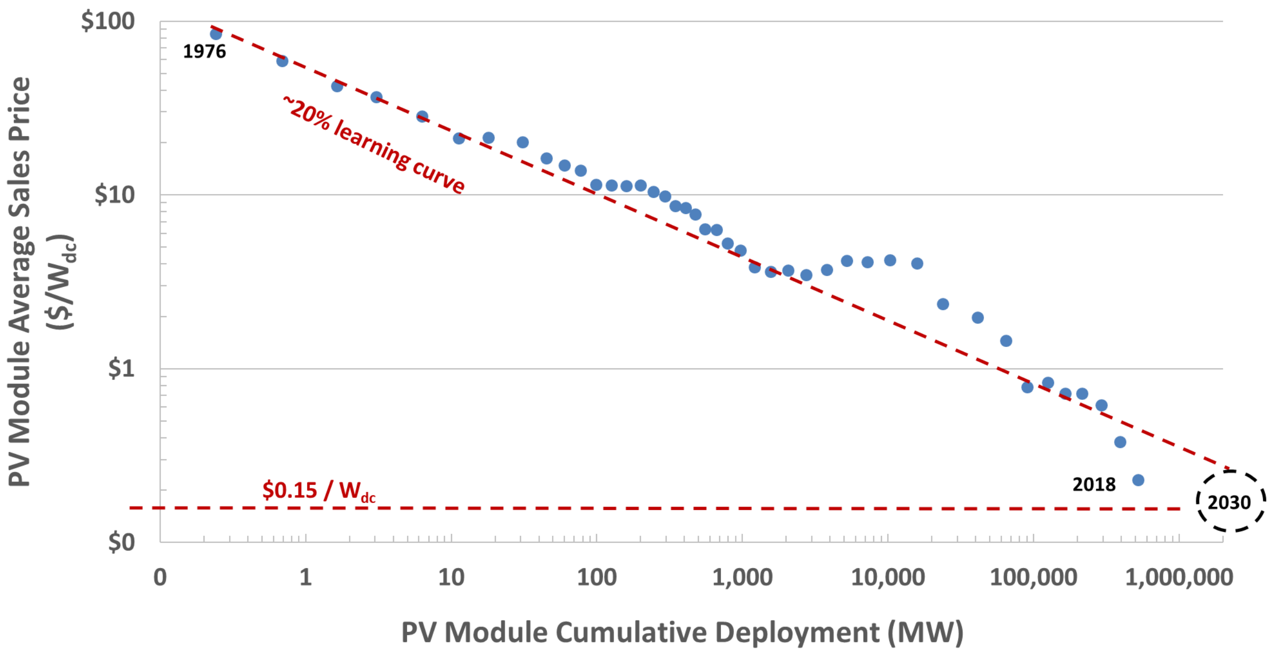

Figure 2-5
PV module price trend, 1975 to 2030E

Sources: SPV Market Research, NREL, EPRI

Operations and Maintenance (O&M) Costs

Aside from capital costs, there are additional costs associated with O&M. Fuel costs are not a concern for renewable resources such as PV or wind, but certain types of DER, such as fuel cells or CHP, are fuel dependent and thus the associated fuel costs need to be considered. Depending on the structure, certain DR programs may incur a similar "fuel" cost in the form of the payment that customers receive for reducing their demand. However, the pricing structure used for such a scheme should be designed with a least cost goal in mind.

As previously mentioned, many NWA technologies are not as mature as traditional assets and there is still a lot to be learned in terms of optimal O&M practices. For example, in some climates, panel washing can be a cost-effective practice to boost performance of solar panels while in other climates it is not. Preventative maintenance costs, such as greasing solar tracking system components or checking for cording electrical connections, can be estimated. However, there remains some uncertainty around equipment failure rates and thus reactive maintenance costs which may be significant. Maintenance practices can be optimized such that marginal O&M costs equal the marginal benefits associated with improved reliability and equipment life. These costs will become better understood with time and more widely available data.

Equipment Life and Replacement Costs

Proper economic comparison between traditional and DER solutions must also consider the lifetime and replacement costs of the solution. Accounting for the escalation or declination of costs when estimating replacement costs is important and can alter project economics. As previously mentioned, NWAs may have lifetimes that are considerably less than traditional solutions. Consequently, it may be necessary to account for the cost of an NWA needing to be replaced or upgraded sooner than a traditional alternative. Conversely, in the case where there is some uncertainty surrounding the identified distribution need, shorter NWA lifetimes could be favorable given their lower risk due to shorter cost-recovery timelines.

Other Avoided Costs

A final consideration is the impact of a given solution on other costs such as energy procurement (whether produced or purchased) or ancillary services. One advantage of energy producing NWAs such as solar PV or CHP is that they not only can help relieve identified distribution constraints but can also offset utility bulk system energy costs. Storage systems may be able to lower energy costs through arbitrage by charging during low cost hours and discharging during high cost hours. NWAs may also be able to help with voltage or frequency regulation and reduce the need for ancillary services. Both traditional and NWA solutions impact voltage profiles which, in turn, can alter consumption and system losses.

In some areas, there may be environmental regulations such as renewable portfolio standard (RPS) or a carbon tax. Implementing renewables producing NWAs, EE, or DR that reduce the need for non-renewable resources can help avoid costs associated with RPS compliance. Although the costs associated with energy, losses, ancillary services, or RPS compliance may not be primary drivers in the choice of an alternative, they could be significant and should be accounted for in the overall economic comparison.

Lastly, the flexibility and portability of NWAs may allow them to offer multiple “stacked services” throughout their expected lifetimes. For example, the ability to move a battery system elsewhere should future load growth fall short of expectations represents a comparative advantage over traditional wires upgrades which lock the utility into population and load projections that could change over time. Further, if designed to be modular, a battery facility may be able to expand at minimal cost if higher than anticipated load growth materializes.

A summary of the economic pros and cons outlined for NWAs is given in Table 2-1.

Table 2-1
Summary of pros and cons related to economics of NWAs

Pros	Cons
• No fuel costs for renewable resources • Potential for providing additional system services • Avoided costs (e.g. RPS compliance, carbon tax)	• Potentially high upfront capital costs • Uncertainties regarding O&M costs • Shorter lifetimes, need to be upgraded or replaced sooner

NWAs in the Distribution Planning Process

In Chapter 1, the existing distribution planning process was outlined with four key steps. Although DERs and NWAs will change parts of the planning process, the underlying structural steps do not need to be altered, as demonstrated in Figure 2-6.

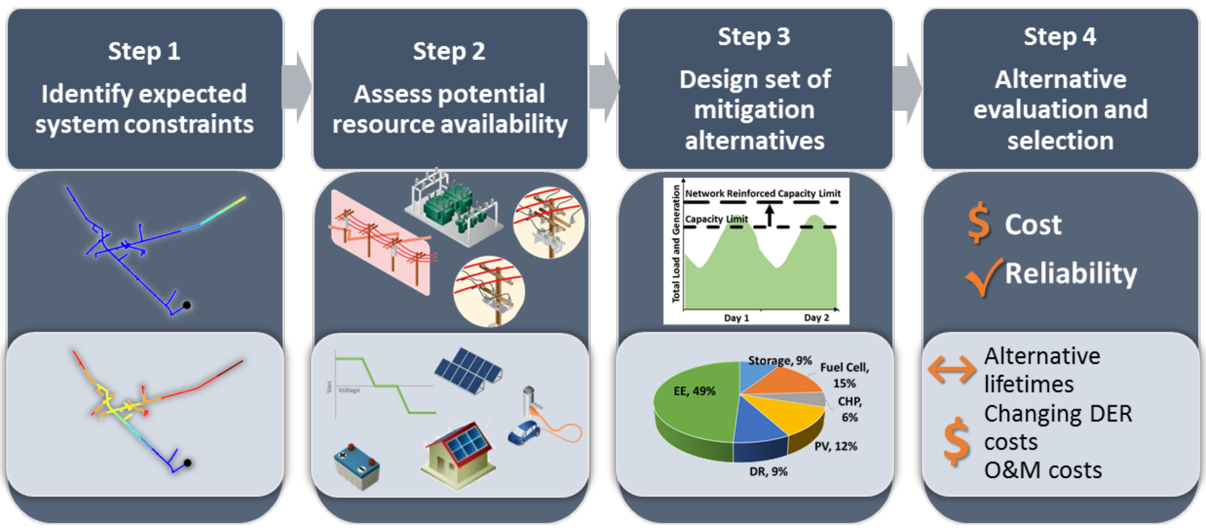

Figure 2-6
Existing and emerging distribution planning process

The steps themselves will, however, be affected by the considerations discussed in this chapter, as highlighted in Table 2-2. Locational and temporal issues will need to be considered as part of Step 2, where resource availability is identified. Additional DER design factors will need to be considered to help narrow down the set of appropriate mitigation alternatives in Step 3. Finally, economic considerations regarding both NWAs and traditional solutions will need to be compared as part of Step 4, where the most suitable solution is selected. Alternatives must be evaluated on an apples-to-apples basis, which can be achieved by defining certain metrics for project prioritization and, in turn, help ensure fair and optimal alternative selection [4].

Table 2-2
Linking considerations to planning steps

Consideration	Affected Planning Process Step
Locational Considerations	2
Temporal Considerations	2
Additional Design Considerations	3
Economic Considerations	4

Designing a Portfolio

As has been mentioned, although certain technologies in isolation may not be adequate to support the needs of the future distribution system, combining them to create a diverse portfolio of DER may provide a more reliable and sustainable NWA. The creation of a portfolio of DER would happen in Step 3 of the emerging planning process described in Figure 2-6, and must incorporate all of the previous considerations that have been discussed.

Once the available resources have been identified based on the distribution constraint and the locational considerations, the share of each resource within the portfolio must be determined – a non-trivial task. To start, the key objectives of the portfolio must be decided upon – it may be that the portfolio should be designed to minimize output variability during the time of the constraint, or to minimize the overall portfolio costs. Optimization methods are one way of calculating the ideal share of resources to achieve the desired objective, while incorporating all of the characteristics and considerations previously outlined for each resource.

3
NWA PROJECT CASE STUDIES

Non-wires alternatives have been employed for over three decades, with early demonstration projects emerging in the early 1990s. However, deployments have been both sporadic and uneven. Moreover, the vast majority of the approximately 40 U.S. projects (330 MW) implemented to date have employed targeted demand-side management approaches, largely comprised of energy efficiency and demand response measures, to offset distribution and transmission system upgrades [12].

Recently, falling technology costs, in part driven by rising deployments, as well as regulatory mandates and policy supports, have sparked a new cycle of NWA development activity that is exploring the use of energy-exporting DERs – primarily solar PV, fuel cells, CHP, wind, and energy storage (which has load and export implications) – to offer distribution system benefits. These projects are leveraging a growing body of DER operations and maintenance experience to plug distributed energy resources into a variety of NWA use cases. In this way, they are helping to evolve traditional utility planning and business models strategies for grid integrating rising penetrations of variable resources, accommodating forecasted load growth, and mitigating associated distribution system constraints.

Today, over 100 NWA projects, totaling 1.4 GW, are in various phases of pipeline development in the United States (see Figure 3-1), the majority of which are expected to come to fruition [12]. Of this pipeline capacity, about 30% is intended to defer distribution (<69 kV) infrastructure investments, via smaller, tactically focused projects (6 MW of average capacity) [13]. And looking ahead, global spending on NWAs is predicted to grow from $63 million in 2017 to $580 million in 2026, a growing portion of which is expected to be earmarked for NWAs composed of distributed generation technologies that can enable distribution deferral through strategically placed locational deployment [14].

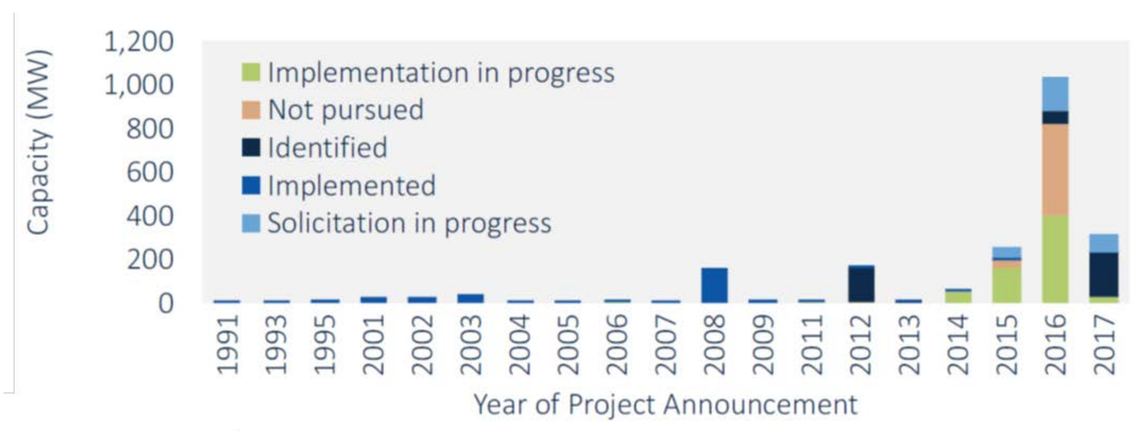

Figure 3-1
NWA Capacity by Year of Project Announcement

Source: GTM Research

This chapter profiles three real-world NWA projects – two existing, and one proposed – to highlight their locational, temporal, design, and economic considerations. The case studies examine each project's guiding rationales, and, where possible, describe identified outcomes. Their intent is to offer comparative insights that can help inform future NWA strategies for meeting short- and longer-term grid planning and management objectives.

The cases, summarized in Table 3-1, are representative of an emerging subset of NWA projects that employ energy-producing DERs largely to delay traditional distribution upgrades. (An expanded accounting of these NWA projects is available in the Appendix.) They have been selected given their collective diversity; relatively well-documented operating, financial, and performance histories; relevance to other utilities and technology developers; replicability; and potential to impart meaningful insights. Each provides an initial understanding of project background and goals, before presenting key economic and logistical issues – including benefit-cost analysis calculations and implementation approaches. Project status and next steps are subsequently discussed, and lessons learned conveyed. References for more information are lastly provided.

Table 3-1
Summary of profiled NWA projects

Utility - Project Name	Technologies / Size	Location / Status	NWA Project Summary
Arizona Public Service – Punkin Center	ES: 2MW / 8MWh	Arizona / Launched 1Q18	Battery system addressing load growth and resulting thermal constraints on a rural feeder by providing peak shaving during 20-30 peak power demand days per year. Other grid services also available via the unit (solar shifting, voltage regulation, etc.) Upshot: upgrade deferral of 16.5 miles of T&D infrastructure over rough terrain. Redundancy and design flexibility incorporated to ensure reliability, add battery capacity to meet future load growth.
Con Edison – Brooklyn-Queens Demand Management (BQDM) Program	DR, EE, PV, ES, FC, CHP, CVR: 52MW	New York / Launched 2014	BQDM employing $200M in contracts for DER, DR, and other load relieving solutions to overcome a sub-Tx feeder constraint thereby delaying construction of a $1.2B area substation, new switching station, and feeders. To date, EE programs have yielded 15 MW in peak load reductions; DR has also made significant capacity contributions; fuel cells and CHP have offered 8 MW of deliverable peak load reduction capacity. Other load relief anticipated from energy storage. Program recently extended by NYPSC.
National Grid – Little Compton Battery Storage Project	ES: 1 MW / 250 kWh	Rhode Island / In Development	To delay a $2.9 million substation upgrade, the utility proposed procuring services from a 250 kW/1 MWh, vendor-owned battery storage system to provide peak load relief through the summer of 2022. The battery was intended to predominately be used to reduce peak from 3:30pm to 7:30pm during June thru September. When not being used for peak load relief, the system was going to be allowed to participate in the ISO-NE energy market. Due to a downwardly adjusted peak load forecast and the presence of significant distributed generation able to help reduce potential grid constraints, the project was no longer deemed necessary and shelved in December 2018.

Arizona Public Service – Punkin Center

Background

In 2016, Arizona Public Service (APS) identified the need to rebuild the transmission and distribution (T&D) infrastructure servicing the rural town of Punkin Center, AZ (located ~90 miles northeast of downtown Phoenix). The town's modest, yet persistent, temperature-driven loads – rising by an average of 1-2% per year – were threatening to create constraints on the sole circuit serving the community, the 21-kV Mazatzal feeder[2], and to overload its thermal limits. Rather than rebuild 16.5 miles of poles and wires through hilly and mountainous terrain, the utility opted to pursue a non-wires alternative solution consisting of a 2 MW/8 MWh battery array that is able to provide feeder capacity through peak shaving and thereby defer system upgrades (see Figure 3-2).

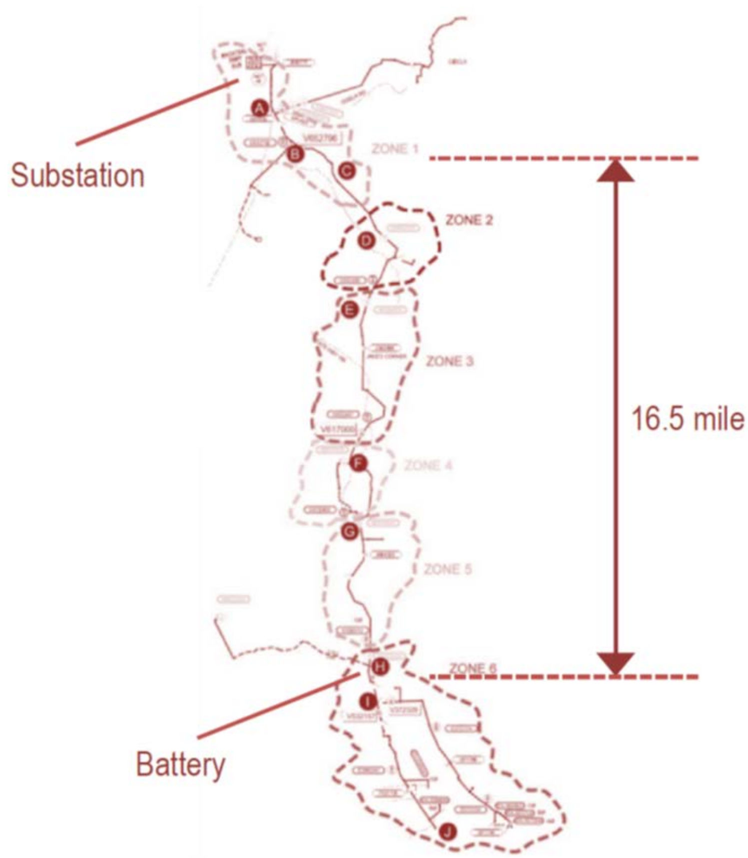

Figure 3-2
The Mazatzal Feeder, Substation, and Battery Unit Serving Punkin Center, AZ

Source: Arizona Public Service

Launched in March 2018, the Punkin Center Battery Storage Project now delivers local peak shifting services to the town's 600 residents during 20 to 30 peak power demand days per year,

[2] The feeder has a 2R line rating of 174 A.

when local and system peaks create feeder constraints.[3] In addition to reducing delivery capacity needs, the battery unit is lowering the area's generation capacity needs, thus lessening the urgency for new generation investments. Its ability to save money through energy arbitrage (i.e. soak up negatively priced energy and dispatch it when costs are higher), is a direct benefit to the utility's customer base. Meanwhile, the NWA installation can also provide grid services to APS, such as solar peak shifting, voltage regulation, and power factor regulation. Because the system is oversized compared to the projected T&D deferral need, it has the capability to serve multiple applications beyond peak shaving simultaneously, if needed.

For APS and the utility industry at-large, the project represents one of the first strategic investments in energy storage in lieu of traditional infrastructure. As such, project findings are expected to inform APS's future NWA activities and influence other utility NWA strategies as well. For instance, APS's ability to plan, deploy, and operate the battery system in approximately nine months rather than pursue a multi-year transmission construction project – and take on the cost risks associated with accommodating 20-30 years of expected load growth that may not materialize – is expected to help prove out the effectiveness of making smaller, incremental investments in DER to help manage grid needs as they arise.[4]

Economic Considerations

APS evaluated several options to determine the least cost, best fit solution for mitigating the constraints on the T&D system servicing Punkin Center. These included diesel gensets, combined solar-plus-storage, battery storage, and a traditional line upgrade. Ultimately, the battery system was found to be the optimal alternative for economically addressing load growth concerns. According to APS, the cost of the system was less than half of the upfront expense of the traditional wires approach. Overall project costs favored the battery too.

Importantly, the Punkin Center project's circumstances contributed to its economic justification. For example, the remote location of the Punkin Center community as well as its growing load demands, the challenges introduced by the surrounding area's rugged terrain, and the battery system's added technological benefits (i.e. value streams) were key to the project's greenlighting. More generally, the technology's portability and falling costs were also a boon to its economic cost-benefit. For example, the flexibility to move the battery system elsewhere should future load growth fall short of expectations represents a comparative advantage over traditional wires upgrades which lock the utility into population and load projections that could change over time. (The battery facility is also designed to be modularly expanded if higher than anticipated load growth materializes.)

Beyond economics, regulatory considerations also contributed to the development of Punkin Center's Battery Project. For example, the utility was able to leverage the NWA effort to help

[3] Construction on the Punkin Center Battery Storage Project commenced in fall 2017 and the system became operational in March 2018.

[4] In total, the NWA project's timeline – including business case and budget approval, RFP and contracting, EPC, commissioning and operations – took several years (2015-2018).

fulfill a 2016 obligation to develop 10 MWh of battery storage as part of the Ocatillo Modernization Project.[5]

Approach and Practical Considerations

The utility ran a competitive bidding process that resulted in the procurement of two 1-MW/4-MWh storage systems from Fluence Energy (nee AES Energy Storage). Under the terms of the arrangement, APS owns and operates the project and has a 10-year maintenance agreement with the developer. Fluence Energy is responsible for assuring that the batteries run at nameplate capacity over the life of the contract (i.e. either by servicing, refurbishing, or replacing degraded modules).

Fluence installed the battery and transformer, while APS provided the land, siting, and pad; a control house; two-way, four-way switch; and contingency generator (see Figure 3-3). To meet the project's reliability requirements, APS built in several layers of redundancy as well as design flexibility for future expansion. For example, critical spare parts, such as switchgear and transformers, are stored on-site to avoid their long procurement lead times. Meanwhile, in the event of a battery outage, APS also configured the battery site so that temporary generators can connect to a spare transformer. It additionally contracted with a local provider of diesel gensets to offer 2MW of emergency back-up, if needed.

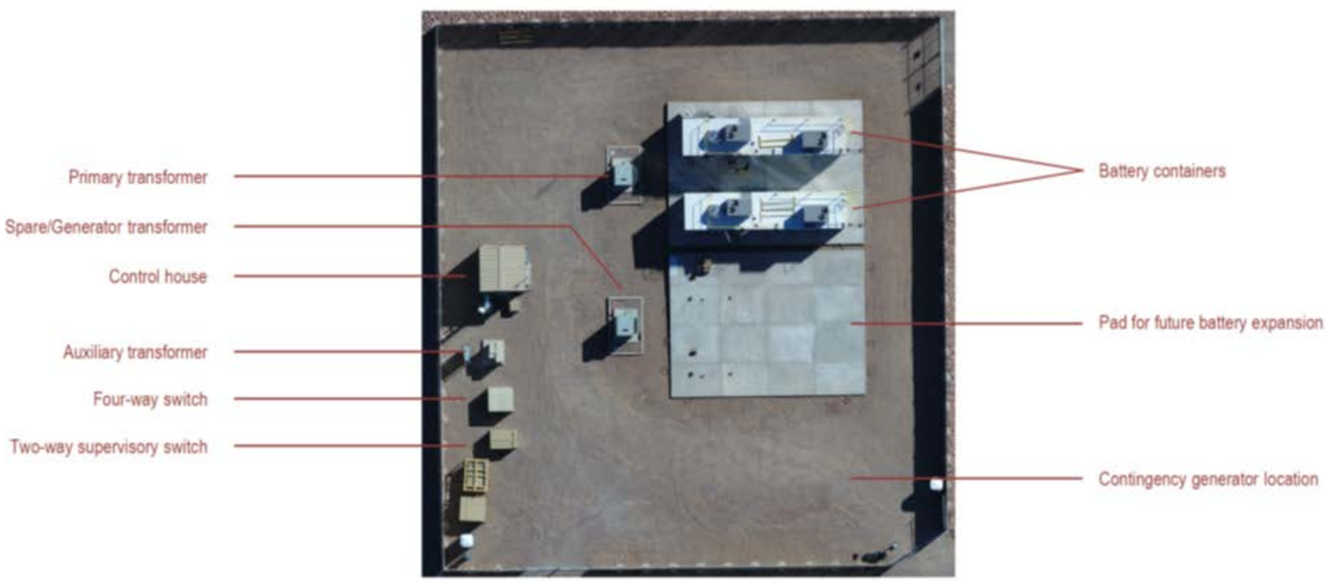

Figure 3-3
Overview of Punkin Center Battery Site

Source: Arizona Public Service

[5] This project is modernizing the Ocotillo Power Plant in Tempe, AZ. Its aim is to implement advanced technology to enable a cleaner-running, more efficient plant. APS intends to install five natural gas combustion turbines and to remove two existing 1960s-era units, among other activities.

Redundant pathways were also incorporated for critical alarms, along with well-defined responses to different communication and protection fault types.[6] To assure connection with the battery unit, APS utilizes MAS monitoring software as a primary path of communication, and spread spectrum as a secondary pathway.[7]

Meanwhile, battery dispatch occurs is three different ways. The primary method involves a routine dispatch schedule that is based on the affected feeder's historical loading. The second method transmits loading information from the feeder head, where the thermal constraint is located, down to the battery through wireless communications. A third method involves installing local metering on the feeder outside of the battery site that is hardwired into the battery controller, thereby allowing continued operations should communication with the battery system be lost. This latter approach (peak shaving mode with local metering), which has not yet been utilized as of this writing, is expected to provide better battery utilization than scheduled dispatch.

Status and Next Steps

The battery installation has been operating on a daily basis since its commissioning in March 2018, and has reportedly provided feeder peak shaving throughout the summer of 2018. Per Figure 3-4, scheduled dispatch was found to be effective on the hottest days of the summer. However, ramp limitations (17 kW/min) – put in place to mitigate issues involving the use of Integrated Volt/VAR Control (IVVC) to manage feeder voltages during reverse power flow conditions – have restricted battery capabilities. (The IVVC software used to coordinate the operation of six voltage regulators did not originally account for reverse power flow conditions that the battery unit could cause during periods of low load. As a temporary fix, the local feeder metering point was leveraged to manage the battery system's maximum dispatch.) A firmware update to Eaton's Yukon platform now allows for the continued operation of IVVC under reverse power flow conditions, consequently enabling more flexible battery operation.

---

[6] Protection fault types include: Ground fault, high current fault, low current/abnormal volt. Fault, arc flash, smoke detected, fire suppression activated, and emergency machine off/E-Stop activated. Communication fault types include: APS RTU to Fluence RTAC comm. loss, APS EMS to RTU comm. loss, and Fluence 24-7 comm. loss.

[7] Spread spectrum is a form of wireless communications in which the frequency of the transmitted signal is deliberately varied. This results in a much greater bandwidth than the signal would have if its frequency were not varied.

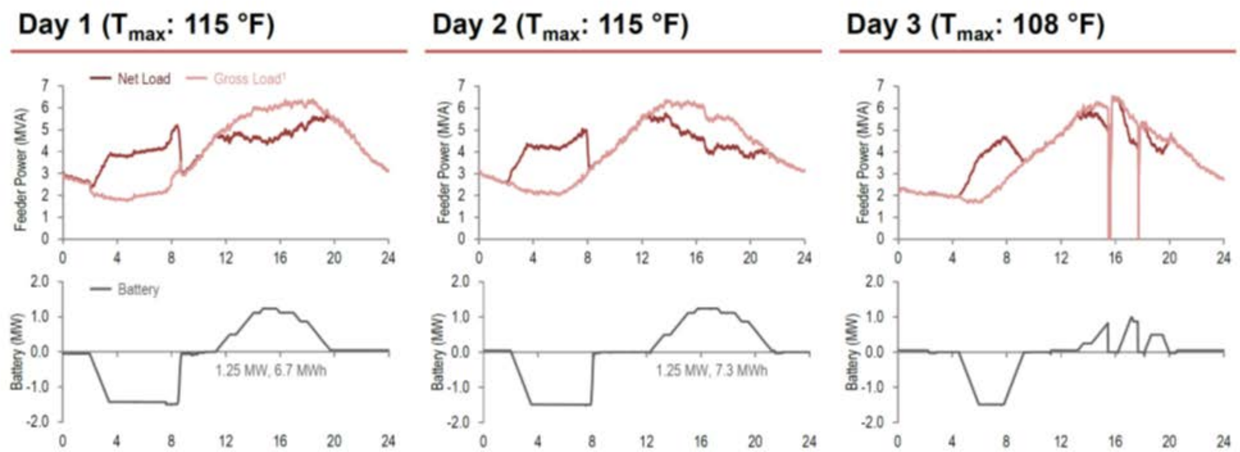

Figure 3-4
Sample Battery Performance during Three Summer Days in 2018

Source: Arizona Public Service

To improve reliability, a control feature has been added to restrict battery charge during specific times of the day, and a contingency generator has been successfully synched to the grid and tested in case of prolonged battery problems. A recent feeder cutover is, separately, relieving some load at the thermal constraint.

Based on data from April to August 2018, a range of feeder- and battery-related faults have caused operational challenges, reducing the battery's daily availability to 96.6%, slightly below the contractual requirement (≥ 98%). Encountered events have included abnormal voltages, ground fault, short circuit, a vendor server outage, and inverter replacement. With accrued project learning, APS and Fluence expect to improve the battery system's availability and performance going forward.

All told, the project has generally met APS's expectations. The utility plans to further study the battery system's performance and utilization as it evaluates the merits of pursuing other NWA initiatives in the 2020 timeframe. It will also share accrued project experiences and lessons learned with interested stakeholders, especially given the initiative's broad transferability (i.e. power reliability and basic grid operation) to other contexts.

Lessons Learned

- **Economic justification is often tied to specific project circumstances.** Punkin Center's rural location, projected load growth, the characteristics and location of the constrained T&D infrastructure, the battery unit's value streams, regulatory considerations, and management buy-in are all factor's enabling the NWA project's development.
- **Thoughtful implementation of battery storage is key to its future success.** Appropriate contingency planning and background research can help project stakeholders realize optimal battery operation, recognize the technology's realistic value propositions, and architect practical service contracts. Meanwhile, implementing the storage solution on a weak feeder can help assure that the unit (and its projected benefits) can be more readily accessed. Making adjustments to installation and operation plans as issues

inevitably arise (e.g. modifying the IVVC function, adapting dispatch options, etc.) are likely to be necessary. Rigorous planning can help avoid cost creep – especially for inaugural NWA projects.

- **Recognize the operating needs of the battery storage unit and plan accordingly.** For example, determining how a storage system will be charged and dispatched in a way that will maximize its utilization and benefit can guarantee its success (i.e. internal controls and data requirements should guide operation). Accounting for line losses can make sure that the battery is appropriately sized.

- **Incorporate appropriate levels of redundancy into the NWA solution to ensure a level of reliability consistent with traditional wires upgrades.** Practical contractual obligations (e.g. for real power availability and round trip efficiency), robust communication architecture, multiple battery dispatch options, back-up plans (e.g. contingency generator, spare transformer), design flexibility to accommodate future expansion due to load growth, and on-site critical spares can all contribute to an NWA project's reliability. These and other approaches can help inform the ingredients that should be accounted for when conducting cost-benefit analyses of battery-based NWA projects.

- **Do public outreach and education.** Keeping local organizations and residents informed about the project, its goals, challenges, and outcomes can go a long way toward generating stakeholder support useful to a project's success.

For More Information

- Punkin Center Battery Storage Video: https://www.youtube.com/watch?v=cjSRvaP7Ucg.

- Edison Electric Institute. *Leading the Way: U.S. Electric Company Investment and Innovation in Energy Storage*. Washington, D.C.: October 2018. http://www.eei.org/issuesandpolicy/Energy%20Storage/Energy_Storage_Case_Studies.pdf.

Con Edison – Brooklyn-Queens Demand Management (BQDM) Program

Background

The Brooklyn Queens Demand Management program (BQDM) can perhaps be considered the "big daddy" of non-wires alternatives projects with a distinctive distribution-focused DER component. Kicked off in 2014, it is one of the largest active NWA projects in the U.S., comprised of roughly 52 MW of traditional customer-side (41 MW) and non-traditional utility-side (11 MW) resources. The portfolio of technologies in the ongoing project is intended to lower demand in a targeted geographic area[8] and postpone the construction of a new distribution

---

[8] The targeted areas in the BQDM program include neighborhoods in north-central and eastern Brooklyn, as well as southwestern Queens: Greenpoint, East Williamsburg, Bushwick, Bedford-Stuyvesant, Crown Heights, East Flatbush, Brownsville, East New York, Richmond Hill, Howard Beach, Broad Channel, Ozone Park, South Ozone Park, Woodhaven, and Kew Gardens.

substation and the expansion of an existing transmission switching substation (Brownsville No. 1 and No. 2) at least until 2026. Figure 3-5 depicts the BQDM's coverage.

The program specifically aims to address a forecasted overload condition of the electric sub-transmission feeders serving the BQDM area by reducing 69 MW of summer peaking load. The peak load-relief need occurs at night (9-10 pm), but the overload period runs 12 hours, from noon to midnight. (In addition to sourcing 52 MW of peak load reduction via NWA solutions, 17 MW in traditional utility infrastructure is helping to mitigate the peak load constraint.)

Figure 3-5
Geographic Boundaries of the BQDM Program

Source: Con Edison, 2018

Having received approval to implement the program from the NY Public Service Commission (NYPSC), Con Edison is now either currently enlisting or has plans to procure/incentivize a range of projects composed of fuel cells, combined heat and power (CHP), energy efficiency (mostly light bulb replacement), battery storage, solar PV systems, and conservation voltage optimization (CVO). These technologies – in addition to commercial, industrial, and residential demand response programs – are helping to relieve the stress on the utility's distribution system during periods of high demand and to generally improve system reliability.

Approach and Economic Considerations

The BQDM program is an outgrowth of New York's Reforming the Energy Vision (NY REV), the state's long-term energy strategy. As part of the NY REV, the NYPSC strongly encourages utilities to alter their planning processes by considering the procurement of needed equipment earlier (i.e. sooner than as a response to identified infrastructure upgrades) and "more broadly incorporate system design into NWA solutions." Con Edison management subsequently decided to forgo the traditional approach of addressing an identified sub-transmission feeder constraint with the build out of new grid infrastructure, by instead implementing a $200 million NWA program with the aim of deferring $1-1.2 billion of T&D investment.[9] The BQDM program has thus far principally sought load reductions for 2017 and 2018, but a program extension, discussed below, is refocusing load reduction efforts to beyond 2018.

Of the program's approved $200 million budget, approximately 75% ($150 million) is allocated to customer-side solutions, and the remaining 25% ($50 million) to utility-side approaches. All expenditures are treated as ten-year capital assets with a regulated rate of return (ROR) based on Con Edison's authorized weighted average cost of capital (WACC).[10] Meanwhile, a return on equity (ROE) adder of 100 basis points, effectively a bonus incentive, is tied to three performance metrics: peak-load reduction, DER provider diversity, and cost savings.[11]

Figure 3-6 illustrates Con Edison's benefit cost analysis (BCA) of the BQDM program (as of 2017). It depicts a comparison of the net present value of the revenue requirements necessary to cover the costs of both the wires alternative and the BQDM approach, including a suitable ROR on the rate-based expenditures and the costs avoided by the BQDM approach during the deferral period. The costs of the BQDM scenario initially exceed those of the wires alternative, but they ultimately fall below those of the wires alternative because the BQDM avoids $99.1 million worth of capacity, energy, distribution, environmental, and line loss costs. As a result, ratepayers are estimated to save $22 million based on BCA results.

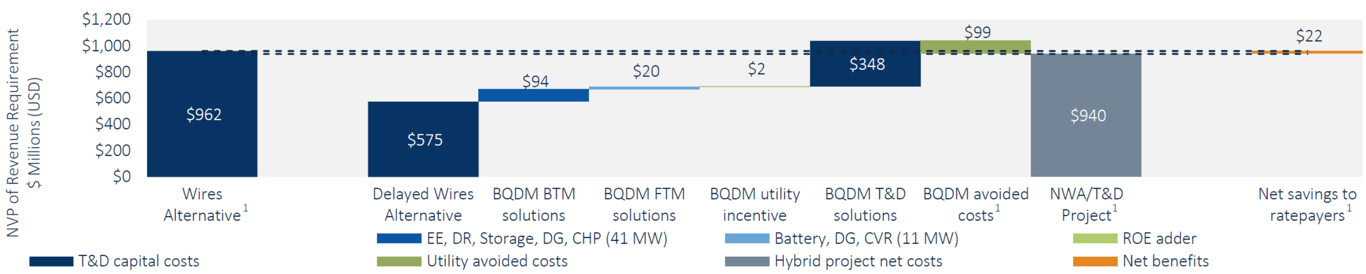

Figure 3-6
NPV comparison of revenue requirements between traditional wires alternative and BQDM program

Source: GTM Research, Q4 2016 BQDM Quarterly Report

---

[9] This traditional approach would have entailed constructing a new area substation, establishing a new switching station, and building sub-transmission feeders by 2017.

[10] In other words, Con Edison is able to recover its BQDM program expenditures over a 10-year period while earning a return on the deferred costs at the ROR approved in its most recent electric rate proceeding.

[11] The ROE adder allows Con Edison to increase the base ROE utilized to calculate the project ROR. The utility will receive 45 basis points (bps) for achieving BTM peak-load reductions beyond the 41 MW proposed by Con Edison (i.e., 1 bp for each MW reduced beyond 21 MW); 25 bps to increase the diversity of DER providers in the service territory (i.e., 1 bp for each 0.01 increment beyond 0.75 in a normalized entropy index used to measure DER provider diversity); and 30 bps for reducing the unitary cost ($/MW) of the BQDM portfolio of solutions relative to the traditional T&D solution (i.e., 1 bp for each 1% reduction in cost relative to the $6 million/MW cost of the wires alternative).

To identify and procure the lowest-cost DER projects for the program, Con Edison administered a request for proposal process, overseen by the regulator.[12] The bulk of the BQDM's customer-side capacity has been acquired through third-party demand response aggregators via reverse auctions. Energy efficiency measures have also significantly contributed to the BQDM program's capacity, largely through the distribution of free lightbulbs and other lighting retrofit technologies. In this regard, new incentives have been successfully marketed via the utility's existing programs to make an immediate impact, and third-party relationships have subsequently been developed to expand offerings.[13]

The BQDM program has separately provided funding to aid in the uptake of CHP in the BQDM area. This funding has supplemented incentives offered by the New York State Energy Research and Development Authority (NYSERDA) under its CHP Acceleration Program. Together, the NYSERDA incentives, with matching funds from Con Edison, have offered potential to potentially cover 70–90% of a CHP project cost, with anticipated returns on investment of 1-3 years.[14] Solution providers have been incentivized to target their efforts in the BQDM areas with heightened requirements to help ensure load reduction. To drum up interest, NYSERDA, National Grid, and Con Edison also developed a joint marketing approach in the BQDM Area.

Fuel cells have also been implemented within the BQDM area to provide system benefit. Con Edison has engaged with customers and fuel cell vendors to evaluate the potential for using fuel cell technology to economically offset baseload consumption. All customers in the BQDM area with verified electric service account numbers have been eligible to participate. Site visits were conducted at select sites and customer bills analyzed to determine the feasibility of the technology's implementation. A partnership between Con Edison and a fuel cell vendor has also helped facilitate the adoption of fuel cells at eligible customer locations.

Con Edison has separately issued calls to contract for "shovel ready" battery storage projects targeting customer-side load reduction opportunities at commercial properties in the BQDM area. It initially received proposals from four respondents and, after review and evaluation of the proposals, communicated an incentive level that was intended to meet the hurdle rate ($/kW) needed to make the projects viable. Ultimately, one battery storage project was installed as part of a multi-technology installation at an affordable housing customer location, resulting in a 300-kW load reduction. Another 500-kW project, later lowered to 100 kW, was expected to provide additional load reduction, but was shelved due to a range of implementation, engineering, and regulatory challenges. Looking ahead, Con Edison plans to install a 12 MWh battery unit during the fourth quarter of 2018. The configuration will allow for a choice of discharge: either 1 MW for 12 hours, or 2 MW for 6 hours.

---

[12] Con Edison issued a Request for Information (RFI) to seek proposals for customer- and utility-side non-traditional solutions for the BQDM Program. It used an RFI instead of a Request for Proposal (RFP) because it felt the former approach could solicit a broader array of responses, while providing greater insight into prevailing prices and the state of the marketplace.

[13] Marketing efforts included providing additional incentives beyond established amounts to target small businesses, multifamily, and commercial and industrial (C&I) customers.

[14] Eligible projects may receive an incentive of up to $1,800 per peak hour kW of load relief. Con Edison will provide a match up to the base incentive provided by NYSERDA, but will not match any bonus incentives that NYSERDA provides.

Con Edison has also implemented enhanced, efficient voltage control via CVO to reduce peak loads in the BQDM area. It separately explored pursuing a utility-side solar PV pilot that intended to leverage 1 MW of PV capacity from installations sited on the grounds of 10 unit substations and other buildings located in the BQDM Area. After review of submitted proposals, however, and pending additional load relief needs, the utility has put the project on hold.

Status and Next Steps

The BQDM program has been active since mid-2014 and was targeted to conclude at end-2018. However, Con Edison recently received an extension from the NYPSC to procure additional load-reducing NWA resources that will extend the program beyond its originally scheduled end date. Generally speaking, the program is considered a success and has met its primary objectives. As of Q2 2018, Con Edison had implemented roughly 40.8 MW of peak hour non-traditional utility side and customer-side solutions. Savings achieved through the program's portfolio of measures have delayed the buildout of a new substation beyond the initial load relief projections. To this end, roughly 6,700 small businesses, 1,660 multifamily buildings, and 21,500 family residences have participated in the program by taking part in energy efficiency and demand reduction measures, as well as other distributed generation initiatives.

Through the initial RFI process, Con Edison determined its portfolio approach could attract enough resources to manage both the BQDM area's peak load as well as the overall substation load profile. Energy efficiency and conservation voltage reduction measures have started out as the lead contributors, respectively delivering about 15 MW and 7 MW in savings during peak hours, as well as during non-peak times. Demand response programs have also been broadly effective. But base-load technologies, such as fuel cells and CHP, are beginning to deliver benefits too, collectively providing multiple MW's of peak-load reduction. Meanwhile, program incentives have supported the interconnection of several commercial scale solar PV systems. And other load relief is anticipated with the installation of energy storage. Table 3-2 summarizes the NWA opportunities that Con Edison has both pursued and tabled as part of the BQDM program. Meanwhile, Figure 3-7 shows the hourly load reduction provided by the different NWA resources leveraged as part of the BQDM program.

Table 3-2
Summary of BQDM program activity

NWA Opportunity	Status	NWA Opportunity	Status
Customer-side Solutions			
Commercial Direct Install	√	Multi-family Energy Efficiency	√
Residential Energy Efficiency Program(s)	√	Bring Your Own Thermostat Adder	√
Virtual Building Audits	√	New York City Housing Authority	√
Direct Customer Activity	√	Dynamic Resource Auction*	√
Fuel Cells	√	Queens Resiliency Microgrid	NP
City Agency Solutions	√	Commercial Refrigeration	√
Combined Heat and Power	√	Battery Storage	√
BQDM Extension Auction	√		
Utility-side Solutions			
Distributed Energy Storage Solution	√	Distributed Generation (DC-Link)	NP
Voltage Optimization	√	Solar PV Pilot	NP
Fuel Cell	NP		

Source: BQDM Quarterly Expenditures & Program Report, Q2 2018
*Notes: "NP" refers to efforts that Con Edison, based on evaluation and study, is no longer pursuing and does not expect to be a part of the BQDM Program portfolio of solutions. * "Dynamic Resource Auction" refers to market-driven approaches to procure DR-type resources with specific performance attributes.*

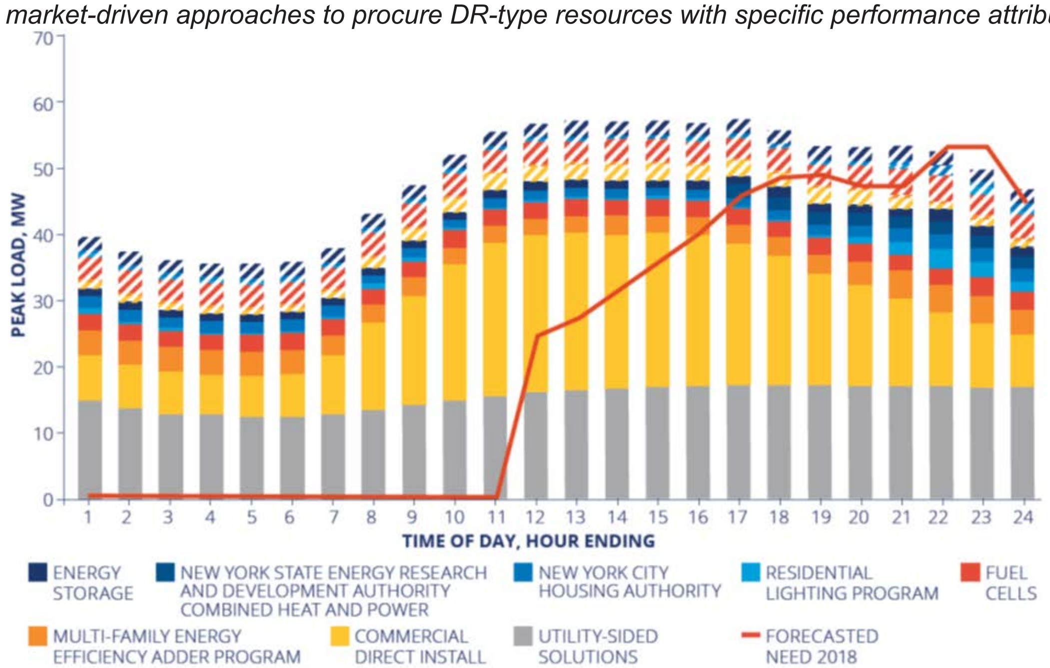

Figure 3-7
Example of hourly load reduction provided by different NWA resources in the BQDM program

Source: Con Edison, 2018

Lessons Learned

- **Regulatory policy is a primary impetus to NWA consideration and development.** The NY REV and consequent NYPSC rulings have provided the foundational motivation – through both carrots and sticks – to enable the BQDM program. Based on the NYPSC's guidance, state IOUs are formalizing the screening criteria they use to trigger the assessment of NWA solutions. Although the NYPSC is pushing utilities to incorporate more inclusive thresholds into their screening criteria, initial utility efforts to develop "suitability criteria" – including level and type of need, lead times, among others – are providing greater definition and, to an extent, transparency to NWA review and potential approval. Separately, as part of REV, the commission has approved two utility-proposed incentives designed to make the utility indifferent to implementing traditional, non-traditional, behind-the-meter, and front-of-the-meter mitigation solutions. These approaches – which include stipulations governing the utility's rate of return and a return on equity adder – have helped incent desired BDQM program outcomes.

- **Despite a helpful regulatory environment and supportive cost recovery rules, NWA-sponsoring utilities will likely encounter ongoing financial and non-financial risks.** Specific to the BQDM program, customer acquisition, vendor contracting, (battery) permitting, proper alignment of customer incentives and compensation structures, and municipal planning and coordination are some of the challenges that have thus far been identified. Con Edison is working to address these and other issues in future NWA planning efforts.

- **Requests for Information may be a better vehicle than Requests for Proposal to initially solicit responses.** Con Edison kicked of the BDQM program by issuing an RFI seeking proposals for customer- and utility-side non-traditional solutions for the initiative. The utility felt this approach could generate a broader array of responses, provide greater insight into prevailing prices and the state of the marketplace, as well as help shape future solicitations. For example, a fuel cell provider was able to leverage its RFI response and collaborate with Con Edison on a customer-sited fuel cell offering. Based on learnings from RFI responses, Con Edison also developed a proposal template to standardize proposal responses and allow for their more consistent evaluations.

- **Proactive engagement with customers and vendors has helped make the BQDM project a success.** Consistent communication between utility personnel and community stakeholders has supported a level of transparency and helped garner the project a positive public response. Meanwhile, vendor engagement has helped prompt BQDM participation and diversify the program's resource portfolio. Vendor interactions have also led to local economic development, with some local employers hiring new staff to fulfill projects in the BQDM area.

- **Planning DER deployments according to their respective lead times can help orchestrate a smoother implementation of technology portfolios.** Con Edison was able to incrementally build out BQDM program capacity reductions by initially pitching existing EE program offerings. As EE uptake ensued, it established demand response programming, and also pursued CHP, fuel cell, energy storage, and other distributed generation initiatives with longer development time frames. As a result, the utility was able to steadily bring capacity reductions online.

For More Information

- BQDM docket: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=14-E-0302.
- BQDM Quarterly Expenditures & Program Report, Q2 2018: file:///C:/Users/pnen001/Downloads/%7BC63D4E53-A72E-4D84-8CAB-9F2A5BC46E09%7D.pdf
- Brooklyn Queens Demand Management Program: Implementation and Outreach Plan: https://www.greentechmedia.com/articles/read/burning-questions-for-the-brooklyn-queens-demand-management-program.

National Grid – Little Compton Battery Storage Project

Background

The era of non-wires alternative projects in Rhode Island effectively began with the enactment of the 2006 Comprehensive Energy Conservation, Efficiency, and Affordability Act. The legislation establishes the Ocean State's "Least-Cost Procurement" policy which, among other things, requires electric distribution companies to strategically consider the deployment of cost effective customer- and utility-sited energy resources to meet system needs. Proposed within National Grid's annual System Reliability Procurement (SRP) Plans, these NWAs include energy efficiency, demand response, and distributed generation measures that principally aim to reduce peak loads while deferring or eliminating the need for new conventional supply (i.e. peaking generators) and/or traditional distribution (and potentially transmission) system upgrades.

The Narraganset Electric Company (d/b/a National Grid) has since either pursued or explored several NWA projects, including the recently concluded Tiverton NWA Pilot, a six-year customer-driven load curtailment effort that successfully deferred substation and feeder upgrades in the coastal towns of Little Compton and Tiverton though targeted energy efficiency and demand response measures.[15] To further delay a $2.9 million upgrade to the Tiverton Substation for another four years, the utility proposed pursuing the deployment of a 250 kW/1 MWh battery storage system to provide peak load relief through the summer of 2022. Known as the Little Compton Battery Storage Project (LCBS Project), this successor NWA initiative sought to demonstrate the feasibility of employing a battery solution to mitigate distribution grid constraints.

---

[15] In 2010, National Grid forecasted that two feeders serving Tiverton and Little Compton would be capacity-constrained during summer afternoon peak hours starting in 2014. The Tiverton NWA Pilot was launched in 2012 to reduce summer peak demand – driven by air conditioning, lighting, and other loads – by up to 1 MW by 2017, thus deferring substation upgrades to at least 2018. After five years of activity, the pilot was discontinued in December 2017 as planned.

Note: In December 2018, National Grid decided to cancel its proposed LCBS project (as well as its later iteration, the Tiverton-Little Compton NWA project) due to a reduced level of loading concern on the area's distribution infrastructure. It was determined that a downwardly adjusted peak load forecast as well as existing and in-queue distributed generation negated the need for the NWA project.

Approach and Economic Considerations

The LCBS Project was a latest attempt by National Grid to address peak load growth as well as distribution system reliability concerns through non-traditional approaches in the communities of Little Compton and Tiverton. Population growth in the two municipalities was nearly twice the state average, and the Tiverton Substation was already too small to support the area's approximately 5,200 customers (80% of which are residential, 20% commercial). Moreover, annual weather-adjusted summer peaks in Tiverton and Little Compton were expected to increase by an average of 0.3% and 0.1%, respectively, for the next 10 years—greater than the anticipated statewide average annual growth rate of -0.2%. (As noted above, a recalculated peak load forecast and identified distributed generation deployment capable of providing peak load relief have since altered the outlook for the area.)

The LCBS Project was intended to provide load relief in the same geographical footprint as the preceding Tiverton NWA Pilot. National Grid planned to enter into a four-year services contract with a 3rd party that would reduce peak load through a vendor-owned battery storage unit. (The vendor would be responsible for engineering, procuring, constructing, and installing the battery.) The 1-MWh storage solution, intended to be sited at Tiverton Public Works Facility, was to be charged from the electric grid and to provide 250 kW of continuous peak load relief for a four-hour period (3:30pm to 7:30pm) chiefly during the months of June through September. This peak load relief need was consistent with the forecasted load growth at the time for the Tiverton Substation.[16] When not being used for peak load relief, the battery was going to be able to participate in the ISO-NE energy market.

National Grid estimated project costs totaling $438,000, split evenly over the effort's four years. The utility had secured an initial $109,500 to implement the project in 2019, and proposed similar funding for each of the three years following (2020-2022). Of the budget amount allocated for 2019, $87,500 was associated with the actual implementation of the solution, including payments to the vendor for load reduction services and maintenance, while $22,000 was associated with vendor management (i.e. overseeing implementation of the system, its monitoring and evaluation). The project's costs were, meanwhile, to be paid for through National Grid's annual system reliability funding plan, which is funded by ratepayers through an Energy Efficiency Program (EEP) charge. (The charge adds roughly $0.01/kWh to Rhode Island customers' bills.)

Results from the utility's benefit-cost analysis confirmed the project's merits. Using the Rhode Island Test, an alternative to the Total Resource Cost (TRC) Test, it calculated that a four-year deferral would deliver $905,197 of localized distribution investment savings for its customers.

---

[16] National Grid estimates that, based on its current peak load forecast, four years is the maximum amount of time the Tiverton Substation upgrade can be deferred with a 1 MWh battery solution.

These benefits represented the amount of revenue requirement that would not need to be collected if the battery system was able to defer grid investments for four years. [17] [18] [19] Additional benefits were estimated assuming a continuous 250-kW peak load reduction over four hours for 20 days per year. (The 20 days per year estimate was based on the average number of days that demand response events were called in the Tiverton NW Pilot each year for 2015-2017.)

Table 3-3 provides an overview of the utility's benefit-cost analysis for the Tiverton-Little Compton NWA Project. With a positive BC Ratio of 2.29, National Grid determined the project to be a cost-effective approach to deferring grid upgrades.

Table 3-3
Little Compton Battery Storage Project Benefit-Cost Summary

Benefit and Cost Categories	Calculated Outcomes
Total Cost	$438,000 ($109,500 x 4 years)
Total Benefits	$1,004,816 ($905,197 in deferral value)
Net Benefits	$566,816
BC Ratio	2.29

Source: Rhode Island 2019 System Reliability Procurement Report

To verify initial estimates and promote learning, National Grid planned to evaluate the capacity demand savings produced by the NWA project through data provided via a metering and control system. Energy savings were to be calculated by measuring the amount of battery power output that is provided during peak periods throughout each calendar year.[20]

Status and Next Steps

National Grid had planned to re-bid the project, recast as the Tiverton-Little Compton NWA project, in the hopes of having an NWA solution installed by early 2019, in time for it to be operable by Summer 2019. It had previously completed an initial RFP solicitation in 2017 that resulted in the selection of a proposed lithium-ion battery storage solution. However, the project was eventually shelved due to, among other things, delays in construction scheduling and equipment availability, which lowered the selected vendor's assessment of the project's value proposition.

---

[17] The revenue requirement is the amount of money that a utility must receive from its customers to cover its costs, operating expenses, taxes, interest paid on debts owed to investors and, if applicable, a reasonable return.

[18] The Tiverton Substation upgrade was originally planned for 2014, so all project benefits were inflated to $2019 to match the proposed NWA Project budget.

[19] The Rhode Island Test is primarily used to more fully account for the costs and benefits of energy efficiency proposals. It is also applied to evaluate non-wires alternatives projects. The calculated deferral of localized distribution investment savings generated by the TLC NWA battery was inserted into the RI Test model as a replacement for the regional distribution benefit in the avoided costs calculated for energy efficiency measures.

[20] The expectation was that the battery would charge during lower wholesale price periods and discharge at higher wholesale priced hours, with the "savings" being the difference in these prices.

In December 2018, National Grid determined that an NWA solution for the Tiverton-Little Compton area was no longer needed due to a downwardly adjusted peak load forecast and the presence of enough distributed generation to help reduce potential grid constraints. However, the utility intends to continue examining additional opportunities to defer investment upgrades for other undersized substations in Rhode Island.

Lessons Learned

- **Develop a risk mitigation strategy for NWAs** to avoid circumstances in which delays and equipment availability may derail projects.
- **Be flexible in load growth forecasts.** Anticipated load growth at a substation may not materialize or it alternatively may accelerate. These outcomes will impact the economics of a NWA deferral project.
- **Measure capacity demand savings to verify initial estimates and promote learning.** National Grid's aim to evaluate the capacity demand savings produced by the LCBS Project through data provided via a metering and control system was intended to promote learning as well as potentially prove out the efficacy of leveraging battery storage to reduce peak load.
- **Consider the tradeoffs of pursuing a third-party services contract versus development of utility-owned project.** National Grid planned to enter into a battery services contract with a 3rd party to reduce peak load. This approach has inherent risks and benefits (e.g. potential for vendor bankruptcy, but also lower costs and reduce utility burden).

For More Information

- 2019 Rhode Island System Reliability Procurement (SRP) Report: http://rieermc.ri.gov/wp-content/uploads/2018/09/2019-srp-report-final-draft.pdf.
- 2018 Rhode Island System Reliability Procurement (SRP) Report: http://www.ripuc.org/eventsactions/docket/4756-NGrid-SRP2018_11-1-17.pdf.
- Overview of the Rhode Island Test: http://www.ripuc.org/eventsactions/docket/4684-NGrid-RITest-Tech%20Session(9-13-17).pdf

4

CONCLUSIONS AND KEY TAKEAWAYS

A non-wires alternative is defined as a utility-driven solution to an identified distribution constraint that defers or eliminates the need for a traditional distribution upgrade. Historically comprised of demand-side management measures that have been employed by utilities for decades, NWAs are now beginning to incorporate energy-exporting DERs, like PV and battery storage, largely as a result of falling technology costs and supportive regulatory directives. These often first-of-their-kind projects are seeking to provide flexibility in deployment (i.e. via incremental implementation); reliability at lower cost relative to traditional wires alternatives; and experiential learning on a range of novel operational, technology, and business model strategies

A critical aspect of an NWA is that the solution be the result of the utility's obligation to serve its customers. For example, DERs that materialize organically and offset the need for a conventional upgrade should not be considered non-wires alternatives; rather, they represent inputs that will change the utility expansion plan. From a distribution planning standpoint, grid connected DERs can be viewed along a spectrum with two overarching perspectives:

1. as resources that may require mitigation and need to be accommodated at the distribution level, or
2. as resources that can be integrated into the distribution system as alternative solutions to traditional distribution upgrades.

Regardless of whether DERs are being accommodated or integrated, they must be included in the overall distribution planning process. That said, distributed energy resources present a unique opportunity for distribution planners to provide innovative and potentially more tailored alternatives to traditional distribution upgrades. However, NWAs may not be directly comparable to traditional solutions, and will likely require additional technical and economic considerations to ensure that reliability of service is maintained. These considerations can be split into four overarching categories:

- *Locational considerations*: Those involving spatial and siting limitations, the location of the constraint, and feeder siting.
- *Temporal considerations*: Those concerning resource availability, output variability, sustainability of response, and resource lifetime.
- *Additional design considerations*: Those encompassing the sizing of NWAs, alternative lead-times, reliability, customer participation, and third-party contractual arrangements.
- *Economic considerations*: Those regarding the costs and benefits associated with pursuing NWA projects given DER performance and lifetime considerations in the context of the regulatory/policy landscape.

The factors to consider for DER as a non-wires alternative are further enumerated in Table 4-1.

Table 4-1
Summary of factors to consider for DER as a non-wires alternative

Category	Factor to Consider	Notes
Location	Geographic	Resource availability
	Grid placement - direction of constraint	Related to nature of constraint, voltage thermal etc.
	Grid placement - proximity to constraint	Important for networked systems
	Alternate configurations	Switching schedules, contingencies
	Hosting capacity	Related to temporal factors
	Space availability	Related to physical sizing factors
	Siting issues	Safety and other restrictions
Temporal	Constraint/output coincidence - instant in time	Time of day - how does the DER output and distribution constraint coincide?
	Constraint/output coincidence - day of year	Day or season - how does the DER output and distribution constraint coincide?
	Sustainability	Duration of output from DER
	Lifetime	Short- vs long-term lifetime. Related to degradation and cycling
	Lead times	Short- vs long-term lead time. Length of procurement process. Forecasting uncertainty
	Charge/discharge times	Related to sizing
	Flexibility	Related to variability and portfolio design
	Controllability	Related to variability and portfolio design
	Resource variability	Related to fuel source
Design *Sizing*	Power	Related to other temporal, location and dispatchability factors
	Energy	Related to other temporal, location and dispatchability factors
	Losses/efficiency	Related to location factors
	Headroom	Related to forecasting uncertainty
	Customer participation	For EE and DR, type and number of customers
	Degradation	Related to temporal factors
Design *Reliability*	Lifetime	Related to degradation, cycling and forecast uncertainty
	Availability	Number of resources, many small or one large
	Probability of failure	Number of critical systems (e.g. resource, power electronics, communications) and their probability
Design *Other*	Third party contracting	Lead time for contracting, risk of going out of business, etc.
	Portfolio design	Desired objective and optimal resource share
Economics	Capital Costs	Related to lead times (upward and downward trend)
	Operational Costs	Fuel costs
	Maintenance Costs	Related to lifetime
	Lifetime and replacement costs	Related to planning horizon
	Avoided costs	Energy, ancillary services, RPS, taxes, etc.

It should be noted that although the number of considerations to be made are substantial, not all factors will be applicable to all NWAs. Additionally, for some factors, there is still much to be learned in order to compare NWAs with conventional distribution upgrades on a like basis. To consider DERs and NWAs as part of the distribution planning process, the overall steps of the existing planning process do not need to change, but the outlined factors will need to become additional considerations within each planning step. This will facilitate fair and consistent comparisons of all available mitigation alternatives.

Key Case Study Observations

To provide industry guidance on the future development of successful NWA arrangements, EPRI profiled three real-world NWA projects—two existing, and one proposed. The case studies highlight each project's locational, temporal, design, and economic considerations in an effort to illustrate their influence on chosen approaches and associated outcomes.

In many ways, all three NWA initiatives – Arizona Public Service's Punkin Center project, Con Edison's BQDM program, and National Grid's proposed Little Compton Battery Storage Project – are each serving as a testing ground for novel technologies, programs, and methods that can deliver distribution system benefits. They are leveraging a growing body of DER operations and maintenance experience to pursue a variety of use cases, and, in turn, helping to evolve traditional utility planning and business models for grid integrating rising penetrations of variable resources, accommodating forecasted load growth, and mitigating associated distribution system constraints.

What follows are observations across the described NWA projects. Reflections are meant to compare and contrast the primary considerations driving each of the projects and convey commonalities and differences that can help mainstream successful utility NWA initiatives.

Locational Considerations

All three NWA initiatives take into account the locations of identified system constraints, and consider potential spatial and siting limitations that may impact the applicability and effectiveness of certain non-traditional mitigating solutions.

- The battery solution at the APS Punkin Center project is sited 16.5 miles downstream of the feeder constraint and can be appropriately dispatched through several methods to mitigate thermal issues, as necessary. The installation has no spatial limitations; it, in fact, has been planned with expansion in mind should load growth require it.
- ConEdison's BQDM program employs a portfolio of DERs to provide targeted load reductions in an urban environment. Utility- and customer-sided installations and schemes, dispersed throughout the project's boundary area, collectively alleviate substation constraints. The multiple and complementary solutions employed overcome siting limitations in a city environment.
- The proposed 250 kW/1 MWh battery installation in National Grid's LCBS project was intended to provide peak load relief through the summer of 2022. The system was going to be located on municipal land to address forecasted load growth at the nearby Tiverton Substation.

Temporal Considerations

Resource availability, output variability, sustainability of response, and resource lifetime are incorporated into the strategies of each of the NWA projects.

- The 2 MW/8 MWh battery at Punkin Center is sized to effectively address thermal constraints on the feeder during 20 to 30 peak power demand days per year. Battery dispatch can occur through three methods and is now coordinated with integrated volt/var control to manage feeder voltage during reverse power flow conditions.
- BQDM's portfolio of customer-sited and utility-owned DERs are designed to complement each other and provide summertime overload relief for a period of 12 hours, from noon to midnight, including the peak load constraint that occurs from 9-10pm.
- The LCBS project's planned battery installation was an extension of a previous NWA that relied on energy efficiency, demand response, and solar PV measures. Stakeholders determined that the battery, given load growth projections, was capable of meeting anticipated grid constraints for a needed four-hour period during the summer months.

Additional Design Considerations

The profiled projects have different requirements related to their sizing, lead-times, reliability, customer participation, and third-party contractual arrangements. BQDM comprises a portfolio of technologies, while the others contain a singular solution type. BQDM relies on behind-the-meter customer installations, while the others employ front-of-the-meter utility arrangements. Meanwhile, BQDM and Punkin Center are further along in their lifecycle, and have generated the kind of operating data and experiential learning useful to facilitating industry education.

- A competitive bidding process was successfully used by APS to procure, own, and operate the Punkin Center battery storage unit. A long-term ten-year contract with a developer assures the batteries run at nameplate capacity. Meanwhile, redundancy has been baked into communications infrastructure to assure constant connection with the battery system. Flexibility has also been incorporated into the site, and contingency generators are on call in the event of a battery outage.
- BQDM is pursuing a portfolio of customer- and utility-side NWA measures to defer traditional wires upgrade. The employed technologies are intended to complement one another to meet project objectives. However, customer acquisition, vendor contracting, (battery) permitting, proper alignment of customer incentives and compensation structures, as well as municipal planning and coordination have introduced challenges.
- National Grid planned to enter into a four-year services contract with a third party that would reduce peak load through a vendor-owned battery storage unit at its Tiverton NWA pilot. An accepted bid for the project was eventually shelved due to, among other things, delays in construction scheduling and equipment availability, which lowered the selected vendor's assessment of the project's value proposition.

Economic Considerations

The three profiled projects are either pilot projects or are mandated by regulatory or legislative bodies. Moreover, the economics driving existing projects appear to pencil out, with benefits outweighing costs over their expected operating lifecycles.

- The Punkin Center Battery Storage Project is oversized compared to the projected T&D deferral need so it can generate savings through energy arbitrage and other grid services such as solar peak shifting, voltage regulation, and power factor regulation. The remote location of the Punkin Center community as well as its growing load demands, the challenges introduced by the surrounding area's rugged terrain, and the battery system's added technological benefits (i.e. value streams) were key to the project's greenlighting.
- The BQDM program is an outgrowth of New York's long-term Reforming the Energy Vision strategy and has leveraged incentives offered by NYSERDA and others to promote program participation. Moreover, the utility is taking advantage of favorable cost recovery terms as well as a return on equity adder that is tied to several performance metrics (peak-load reduction, DER provider diversity, and cost savings). The costs of the BQDM scenario exceed those of the wires alternative, but once savings from avoided capacity, energy, distribution, environmental, and line loss costs are factored in, the project results in a net savings to ratepayers.
- The LCBS project's costs were going to be paid for through National Grid's annual system reliability funding plan, which is funded by ratepayers through an Energy Efficiency Program (EEP) charge. National Grid's benefit-cost analysis using the Rhode Island Test, an alternative to the Total Resource Test, calculated that a four-year deferral would deliver savings for its customers.

5 REFERENCES

[1] “Incorporating DER into Distribution Planning,” EPRI, Palo Alto, CA, 2018, 3002010997.

[2] “Solar PV Market Update Volume 16,” EPRI, Palo Alto, CA, 2015, 3002005779.

[3] “Review of Environmental Life-Cycle Assessments of Lithium Ion Batteries for Grid-Scale Storage,” EPRI, Palo Alto, CA, 2017, 3002009392.

[4] “Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process),” California Public Utilities Commision, 2018.

[5] “Wind Turbine Asset Management Technology Assessment,” EPRI, Palo Alto, CA, 2010, 1019773.

[6] “Budgeting for Solar PV Plant Operations & Maintenance: Practices and Pricing,” EPRI, Palo Alto, CA, 2015, 3002006218.

[7] “Strategic Intelligence Update: Energy Storage & Distributed Generation, July 2018,” EPRI, Palo Alto, CA, 2018, 3002013504.

[8] “Addressing Solar Photovoltaic Operations and Maintenance Challenges: A Survey of Current Knowledge and Practices,” EPRI, Palo Alto, CA, 2010, 1021496.

[9] “Integration of Energy Efficiency and Demand Response into Distribution Planning Processes,” EPRI, Palo Alto, CA, 2008, 1015985.

[10] “Utilization of Energy Efficiency and Demand Response as Resources for Transmission and Distribution Planning,” EPRI, Palo Alto, CA, 2008, 1016360.

[11] “New Energy Outlook 2018,” Bloomberg New Energy Finance, New York, 2018.

[12] “Non-Wires Alternatives: Emerging, Maturing, or Stalled?,” GTM Research, Boston, 2018.

[13] “Non-Wires Alternatives Projects: Emerging Utility Revenue Sources for the Distributed Energy Market,” GTM Research, Boston, 2017.

[14] “Traditional Transmission and Distribution Solutions: Market Drivers and Barriers, Business Models, and Global Market Forecasts,” Navigant Consulting, Chicago, 2017.

A
REPRESENTATIVE NWA PROJECTS WITH ENERGY-EXPORTING DER

Non-wires alternatives projects are steadily gaining traction as DER costs continue to fall, and technology operations and maintenance experience progressively accrues. Regulatory mandates along with supportive incentive schemes are also helping to stimulate development. Collectively, these overarching drivers are catalyzing novel NWA initiatives that primarily aim to produce distribution system benefits, like infrastructure upgrade deferral, via a range of use cases. Moreover, many of these trailblazing efforts are departing from historical approaches that exclusively apply energy efficiency measures and demand response schemes. Instead, they are leveraging energy-exporting resources – such as solar PV, fuel cells, CHP, wind, and energy storage – to achieve both short- and longer-term objectives.

Table A-1 provides a representative list of these emerging NWA projects, including key details about each project's utility sponsor, size (kW and/or kWh), technology composition, location and status, and background. As shown, the project group includes a diversity of DERs and approaches. Some comprise a portfolio of technologies, while others contain a singular solution type. Some rely on behind-the-meter customer installations, while others employ front-of-the-meter utility arrangements. Meanwhile, some are further along in their lifecycle than others, and have generated the kind of operating data and experiential learning useful to facilitating industry learning. Though still relatively small in number, these newer, often experimental, NWA initiatives are helping to inspire like-minded projects each with a unique set of location, temporal, design, and economic considerations.

Table A-1
Representative NWA projects that employ energy-exporting DERs

Utility - Project Name	Technology / Size	Location / Status	Summary Details
Arizona Public Service – Punkin Center	ES: 2MW / 8MWh	Arizona / Launched 1Q18	Battery system addressing load growth and resulting thermal constraints on a rural feeder by providing peak shaving during 20-30 peak power demand days per year. Other grid services also available via the unit (solar shifting, voltage regulation, etc.) Upshot: upgrade deferral of 16.5 miles of T&D infrastructure over rough terrain. Redundancy and design flexibility incorporated to ensure reliability, add battery capacity to meet future load growth.
Central Main Power (Avangrid) – BoothBay Pilot Project	EE, DR, PV, ES, diesel gen: 1.85 MW	Maine / Launched: 4Q13, Completed: 2Q18	Utility worked with 3rd party provider GridSolar to develop/operate DG, EE, DR to avoid $18M Tx line rebuild to the Boothbay region (primarily thru load reduction). Battery and thermal energy storage technologies deployed in 2013-2015, along with a diesel-fueled back-up generator, EE commercial lighting, and rooftop PV. Project terminated due to lower than expected electric load growth. Project costs totaled $6M, saving ratepayers ~$12M (present value terms) in avoided stranded costs from an unneeded Tx project alternative.
Con Edison – Brooklyn-Queens Demand Management (BQDM) Program	DR, EE, PV, ES, FC, CHP, CVR: 52MW	New York / Launched 2014	BQDM employing $200M in contracts for DER, DR, and other load relieving solutions to overcome a sub-Tx feeder constraint thereby delaying construction of a $1.2B area substation, new switching station, and feeders. To date, EE programs have yielded 15 MW in peak load reductions; DR has also made significant capacity contributions; fuel cells and CHP have offered 8 MW of deliverable peak load reduction capacity. Other load relief anticipated from energy storage. Program recently extended by NYPSC.
National Grid – Little Compton Battery Storage Project	ES: 1 MW / 250 kWh	Rhode Island / In Development	To delay a $2.9 million substation upgrade, the utility proposed procuring services from a 250 kW/1 MWh, vendor-owned battery storage system to provide peak load relief through the summer of 2022. The battery was intended to predominately be used to reduce peak from 3:30pm to 7:30pm during June thru September. When not being used for peak load relief, the system was going to be allowed to participate in the ISO-NE energy market. Due to a downwardly adjusted peak load forecast and the presence of significant distributed generation able to help reduce potential grid constraints, the project was no longer deemed necessary and shelved in December 2018.
National Grid – Old Forge	ES: 19.8MW / 63.1 MWh	New York / In Development	Microgrid project seeks to improve the reliability on a radial, 46 kV sub-Tx line that feeds 5 substations in 3 New York counties by sectionalizing a fault and serving impacted customers during an outage. The effort presents an opportunity to improve the CAIDI and SAIFI reliability scores for the 7,700 residential and commercial customers in the area. An RFP issued in 2017 generated 9 proposals, nearly all of them containing energy storage. RFP award expected in 1Q19.
National Grid – Nantucket Battery Storage Project	ES, diesel gen: 6 MW/48 MWh and 10 MW	Massachusetts / In Development	Utility procuring a Tesla battery, to be installed by 2019, in order to delay the construction of a third undersea transmission cable to meet increasing summer peak demand. (Peak demand is double the load experienced during non-summer months.) The battery is expected to defer the construction of the undersea cable (price tag: $75M-100M) by 15-20 years, or 3-8 years beyond the current forecast. Two existing 3-MW diesel generators will also be replaced by a 10-MW unit for emergency back-up.

Utility - Project Name	Technology / Size	Location / Status	Summary Details
Pacific Gas & Electric – Angel Island	PV, Wind, NG, ES: TBD	California / unclear	Originally pursued as a demo (E) project under the utility's distributed resources plan (DRP), the NWA seeks to replace 2 undersea 12 kV cables serving Angel Island. Preliminary study proposed 2 NWAs comprised of wind, PV, battery storage, and propane/natural gas back-up. DER technology make-up still TBD. The solicitation seeks bids from a variety of front- and behind-the meter DER technologies.
Pacific Gas & Electric – Chowchilla, El Nido Substation (Demo Project C)	DER: TBD	California / In Development	Part of PG&E's distribution resources plan (DRP), project seeks 4 MW of distribution baseload capacity by summer 2019 or 2020, and 1 MW of distribution peak capacity by April 2019 or 2020 to demonstrate DER's locational benefits to provide Dx capacity services for mitigating overload.
Pacific Gas & Electric – Oakland Clean Energy Initiative	ES, EE: 45 MW	California / In Development	Approved by CA regulators in March 2018, PG&E and local electricity supplier East Bay Community Energy will use DER to replace an outdated fossil fuel peaker plant and serve Tx reliability needs. Projected NWA cost is $102M vs. $537M in new Tx infrastructure.
Southern California Edison – Distributed Energy Storage Integration (DESI) Pilot 1	ES: 2.4 MW / 3.9 MWh	California / Launched 2015	A utility-side Li-ion battery from NEC Solutions (procured thru a competitive bidding process) is deferring upgrades to a 12 kV distribution circuit and increasing reliability by providing load management services to support summertime peaks. In addition to limiting load, the system can simultaneously support circuit voltage or control reactive power flow at the substation. It is a dedicated, single-point grid reliability device rather than a dual-use system (i.e. one that can also participate in the CAISO market when not being used for reliability). The battery, located in a compact customer location, is maintained by a 3rd party and owned/operated by the utility as a grid asset.
Southern California Edison – Distributed Energy Storage Virtual Power Plant	ES: 85 MW	California / Launched 2016	Utility partnering with 3rd party provider Stem to deploy customer-sited energy storage that can contribute flexible capacity over 10 years. The project is part of the utility's effort to meet its long-term local capacity requirements (LCRs) by 2021, which have been exacerbated by the closure of the San Onofre Nuclear Generating Station and anticipated NG retirements in Southern California. It leverages Stem's AI platform to control and dispatch a virtual power plant (VPP) of distributed resources on a repeatable, real-time, day-ahead and targeted geographic basis. As a result, the VPP serves as a firm, on-call dispatchable, peak capacity resource that applies storage systems as demand response. >100 systems currently participating, with more in the construction phase. Customer contracts include fixed monthly subscription payments; the utility hopes avoided cost savings will exceed payments by 2-3x.

Sources: SEPA, PLMA, GTMR, EPRI

Note: CVR = Conservation Voltage Reduction; CHP = Combined Heat & Power; DR = Demand Response; EE = Energy Efficiency; ES = Energy Storage; NG = Natural Gas; PV = Photovoltaics

Export Control Restrictions

Access to and use of this EPRI product is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or U.S. permanent resident is permitted access under applicable U.S. and foreign export laws and regulations.

In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI product, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case by case basis an informal assessment of the applicable U.S. export classification for specific EPRI products, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes.

Your obligations regarding U.S. export control requirements apply during and after you and your company's engagement with EPRI. To be clear, the obligations continue after your retirement or other departure from your company, and include any knowledge retained after gaining access to EPRI products.

You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of this EPRI product hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI members represent 90% of the electric utility revenue in the United States with international participation in 35 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together…Shaping the Future of Electricity

3002013327

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com