

**STATE OF CONNECTICUT**

PUBLIC UTILITIES REGULATORY AUTHORITY

DOCKET NO. 17-12-03RE07

PURA INVESTIGATION INTO DISTRIBUTION SYSTEM PLANNING OF THE ELECTRIC DISTRIBUTION COMPANIES – NON-WIRES ALTERNATIVES

ATTACHMENT A – STRAW NON-WIRES ALTERNATIVES PROGRAM DESIGN

1. **BACKGROUND**

Pursuant to §§ 16-11, 16-243w, and 16-244i of the General Statutes of Connecticut (Conn. Gen. Stat.), and in accordance with the Interim Decision dated October 2, 2019 in Docket No. 17-12-03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies (Interim Decision), the Authority establishes the non-wires alternative solutions process and program (NWA Solutions Program) defined herein.

On June 18, 2020, the Public Utilities Regulatory Authority (Authority or PURA) initiated Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, to establish a transparent and competitive process for comparing potential non-wires alternatives (NWA) against traditional distribution system upgrades and other utility expenses. This process will substantially improve upon existing electric distribution company (EDC) approaches and will seek to leverage competitive forces to drive down the costs of both traditional distribution system capital and operational expenses and future NWA solutions in Connecticut in accordance with the Framework for an Equitable Modern Grid (EMG).[[1]](#footnote-2) This process will also aim to unlock the potential benefits streams, both electric system and non-electric system benefits, associated with NWAs to achieve the objectives of the EMG. The NWA Solutions Program will be implemented within the service territories of the Connecticut Light and Power Company d/b/a Eversource Energy (Eversource) and The United Illuminating Company (UI; collectively, electric distribution companies or EDCs).

1. **Conduct of Proceeding**

The Authority held two Solutions Days in the instant proceeding on August 4, 2020 and August 26, 2020. On September 29, 2020, the Authority issued a Notice of Request for Written Comments due November 13, 2020. The Authority reviewed the comments submitted in response to its September 29 Notice, including those comments submitted by the Department of Energy and Environmental Protection (DEEP), the Office of Consumer Counsel (OCC), the EDCs, as well as the comments submitted by other interested stakeholders. Additionally, the Authority issued two sets of interrogatories on December 21, 2020 and January 4, 2021.

With appreciation for those comments and input, the Authority issues this Straw Proposal. The Straw Proposal includes a discussion of the following program elements:

1. Program Administration
2. Suitability Criteria for NWA Solutions Expected to Evolve with Experience
3. NWA Screening Process Among the EDCs and Stakeholders
4. Competitive Solicitation Process
5. BCA Framework Elements
6. NWA Resources that Qualify to be Considered and Use Cases
7. Performance Criteria
8. Measurement and Verification Plan Requirements
9. Ownership Models
10. Market Engagement Strategies
11. Equal Playing Field for Ratepayers to Keep Costs Down
12. Participation of NWA Resources in Other Programs and Markets

The elements of the NWA program design outlined above will be developed more fully by the Third-Party Program Administrator (Third-Party Administrator) and will require additional stakeholder engagement. Upon issuance of the final Decision in the instant proceeding, the Authority will request that the EDCs, DEEP, OCC, the Connecticut Green Bank (CGB), and other stakeholders work with the Third-Party Administrator to develop, for the Authority’s review and approval, the appropriate program documents and additional program rules necessary to effectively implement the final version of this NWA Solutions Program design (Program Design Documents) outlined in the Straw Proposal.

The Straw Proposal also includes a discussion of utility cost recovery and utility incentives.

1. **GOALS AND OBJECTIVES IN ESTABLISHING A NON-WIRES ALTERNATIVES (NWA) TO TRADITIONAL WIRES AND SUBSTATIONS INVESTMENT PROCESS**
2. **NWA Solutions are now feasible and may be less expensive for ratepayers and more reliable for customers**

Unlike the 20th century, needs on the transmission and distribution system, e.g., a new distribution line or a capacity upgrade, may now be addressed through a solution such as a battery or a set of passive energy efficiency investments. Traditional distribution system investment such as expanding substations, upgrading and replacing transformers, and other infrastructure can now be accomplished in some cases by non-traditional “non-wires alternatives” (NWAs) including both distributed energy resources and grid-scale resources and including technology applications such as energy storage, demand response, and controls systems enabling more tailored and less expensive grid investments. Compared to traditional distribution or substation plant additions, a NWA solution may be less expensive, more reliable, more resilient, more flexible -- or all the above. Because the NWA solution might be less expensive or have significant broader energy system benefits, it can save ratepayers money. Because a NWA solution might be more reliable, resilient or flexible, it may offer great customer value.

Eversource has argued strongly for a distribution utility-driven approach of NWA consideration and planning.[[2]](#footnote-3) While the Authority acknowledges the vital role of the EDCs in any NWA process or program, the Authority rejects the suggestion that the EDCs alone should conduct the screening, selection, and implementation of any NWA program. NWAs by their nature as alternatives to traditional utility infrastructure, made technologically and economically feasible by advanced technologies, may be better understood and more economically and reliably implemented by non-utility energy companies. Both Eversource and UI propose and comment that utilities must control and implement, if not own, NWAs.[[3]](#footnote-4) The Authority finds this stance concerning. When the conditions of a natural monopoly do not exist, possible competition is preferable so long as safe, affordable, and reliable service is thereby furthered. NWAs present just this opportunity.

The process by which electric distribution companies previously undertook significant distribution system upgrades needs to be re-assessed to ensure these distribution wire and substation additions are necessary in light of new technologies that may be less expensive or better solutions, particularly if evaluated through the lens of resilience. The Authority notes that some solutions are available from non-regulated and non-utility advanced energy companies that now can compete with traditional utility infrastructure in ways that were not possible even two decades ago. The current status quo is not designed to optimize utility investments with customer-side resources. The NWA process is intended to include more resource options, more transparency to how those options are evaluated, and to optimize outcomes across parallel programs that use customer-side resources in competition with traditional utility investments.

Further, the utilities’ exclusive control over customer and grid data is now potentially a barrier to desired sharing of system data with third parties. Third party entities may be able to develop less expensive, more reliable and/or innovative solutions to traditional utility wires and substation builds in Connecticut as they have done so in New York,[[4]](#footnote-5) Maine,[[5]](#footnote-6) Rhode Island, and California.[[6]](#footnote-7) However, such innovative companies simply cannot develop and propose any solution without access to adequate utility distribution engineering, system data, and planning and costs options to address modern grid and customer needs. More specifically, for third-party solutions to be viable from a utility planning perspective, third parties need to have access to utility plant need identification data, and any needs assessments and utility investment plans both sooner and to a much greater degree than in the past.

In 2021, when distributed resources can provide less expensive options for ratepayers than some utility investment, consideration of NWAs in a transparent process open to the public and other energy service provides is now part of prudent utility planning. Examples of the value NWAs provide are listed in Appendix A. The Authority notes that in multiple well-known examples of NWAs, the NWA itself combined with delay in the planned T&D upgrades and a hard look over time at the planned utility investment and implementation of alternatives led to cancellation of the utility investment as unnecessary. So, avoidance as well as deferral of traditional T&D infrastructure is possible.

For these reasons, Connecticut needs a new system to fairly evaluate utility and non-utility solutions – to put competing utility and competitive solutions on an equal playing field and opportunity to compete for the most effective least-cost solution. That is not possible where the utility controls information and data on distribution system needs and makes critical table-setting decisions years in advance.

Ultimately, as competition becomes increasingly viable with traditional monopoly utilities, the role of energy regulators is to ensure there are viable processes and space for that competition to occur – in short, the development of an open NWA process is a direct evolution of PURA’s regulation to ensure reliable, safe, and affordable electricity service.

1. **Goals of Connecticut’s NWA Solutions Program**

The goals that the Authority adopts in establishing the NWA Solutions Program for Connecticut’s investor-owned EDCs are:

1. Improving the evaluation of distribution needs and planning transparency for significant additions;
2. Leverage market competition to reduce prices and improve customer service;
3. Fully pursue and capture reasonable benefits for Connecticut ratepayers and businesses, including values beyond the distribution grid to save money on reducing regional costs and undertake resilience measures; and,
4. Furthering Connecticut’s clean energy, climate action, and renewable goals and mandates.

First, PURA’s aim is to establish a transparent process for comparing potential NWA solutions against traditional distribution system upgrades. This process needs to be transparent to allow non-utility third parties the opportunity to provide superior value in meeting distribution system needs; those providers are currently unable to do so without changes to increase the transparency of utility grid information. Utility information superiority can stop competition before it ever occurs or ensure a competitive advantage for the utility. Consequently, Connecticut needs transparency on how distribution system investment is considered, what distribution needs exist, and a process to share that information with companies offering alternatives years in advance.

Second, the process aims to leverage competitive forces. Properly harnessed competition can bring down prices to consumers and improve service. Because competition for utility distribution services is now able to be competitive, PURA recognizes this reality and the potential for alternative measures to provide superior solutions in some regards to traditional utility upgrades.

Third, the process should fully capture all reasonable benefits that solutions provide to and for Connecticut customers. NWA projects have the possibility of reducing costs. NWAs also may be more reliable, as energy efficiency NWAs in Vermont have shown. Values beyond the distribution system should be captured too when reducing the expense of transmission, capacity, and peak energy supply payments by Connecticut’s customers results from a distribution NWA. Bulk-power and regional market savings on the wholesale side can provide substantial savings too. Other solutions that combine resources might service distribution system needs and also provide enhanced customer resilience for storm operations through islanding, microgrid, or behind-the-meter solutions that simultaneously address distribution system needs.

Fourth, the process should maximize benefits to Connecticut’s customers in implementing Connecticut’s Global Warming Solutions Act, renewable energy goals codified under the State’s Renewable Portfolio Standard, more than a decade of supportive climate and clean energy legislation starting with Public Act 11-80, DEEP’s Comprehensive Energy Strategy[[7]](#footnote-8) and Integrated Resources Plan, and the Authority’s Framework for An Equitable Modern Grid.

[The Authority set forth the following objectives in its Equitable Modern Grid Interim Decision, pp. 3-4](http://www.dpuc.state.ct.us/dockcurr.nsf/0/98b91b64d734d3368525848700598fe1/$FILE/171203-100219%20InterimDecision.pdf):

The Framework . . . is consistent with the clear policy directive of the General Assembly over the past decade as first expressed in Public Act 11-80, An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut’s Energy Future. In the years since enactment of Public Act 11-80, an impressive suite of varied energy policies have been considered by the General Assembly; however, not all of these initiatives have been incorporated into utility plans or reflected in the Authority’s approach to regulation. Thus, the Framework will endeavor to maximize the benefits associated with energy policies duly adopted by State policymakers by addressing any lingering barriers to their cost-effective proliferation through a comprehensive, overarching planning process.

The Authority’s Framework for an Equitable Modern Grid will enable an economy-wide transition to a decarbonized future (objective 2) by not only planning for the decarbonization of power generation, but also for the transportation sector and building heating and cooling sectors. The Framework will leverage the work of the [DEEP] in analyzing pathways to a 100 percent zero carbon target for the electric grid by 2040 in the Integrated Resource Plan (IRP) and will ensure that cost-effective, efficient approaches are in place to deliver on those pathways. *The Framework will investigate the barriers to, and improve the integration of, distributed energy resources such as solar PV and electric storage.* Moreover, the Framework will ensure that the electric sector is positioned to facilitate the deployment of ZEVs and renewable thermal technologies (RTTs) as a pathway to decarbonization. (emphasis added, footnotes omitted)

1. **PROGRAM DESIGN**
   1. **Program Summary**

The NWA Solutions Program will rely upon input from the EDCs, DEEP, the OCC, the Connecticut Green Bank, and stakeholders to identify appropriate NWAs from among all proposed distribution system investments over $500,000 in any year on any feeder, circuit, or substation. Those distribution system needs shall be identified at least five years before any planned utility investments to address anticipated reliability violations, resilience standards, infrastructure replacement, or load growth. The Authority expects the EDCs to identify distribution system upgrades as a result of their capital and operational planning to ensure reliability, safety, and adequate service in light of changing customer needs including increased levels of distributed energy resources (DERs) and beneficial electrification.

The Authority will rely upon an independent third-party NWA administrator working as a consultant to PURA to review submissions from EDCs on all distribution system investments over $500,000 as well as proposals and comments of third parties. The independent NWA administrator shall be retained by PURA and be independent of the EDCs and interested stakeholders. The NWA process shall be conducted in public meetings to the extent feasible and mandated by law. However, at the EDCs’ request and as PURA finds necessary and consistent with the law, the independent third-party NWA administrator and interested third parties will execute non-disclosure agreements (NDA’s) and confidential energy infrastructure information (CEII) agreements to review EDC’s projections of violations, distribution system needs, and EDC proposed solutions.

It is PURA’s intent that all significant utility investments (i.e., over $500,000) be reviewed by the independent NWA administrator in concert with interested stakeholders, DEEP, and the OCC to determine if lower-cost and/or more reliable and resilient alternatives to a traditional utility project are feasible and cost effective. The Authority invites third-party energy companies to participate as stakeholders and potential bidders on NWA projects. It is the Authority’s purpose to enhance a competitive market for alternative energy services in Connecticut and particularly to establish a program to invite interested third parties to participate and submit proposals for any NWA.

The Authority does not anticipate that potential status as a bidder will be sufficient basis for an EDC or the Third-Party Administrator to deny access to distribution system data to a third-party that agrees to abide by an NDA and CEII agreement as necessary. Potential bidders for NWAs, in fact, should have access to information on potential NWA needs at the same time the utility evaluates those needs. This means the distribution planning process must be *much more open and transparent*.

In the 21st century when NWAs have proven to be cost effective, distribution system planning need to adjust to the possibility that new technologies make NWAs feasible. While both utilities and non-utility third-party energy providers can design and implement NWAs, the Authority is focused on ensuring that the process is fair so that non-utility providers can compete to offer innovative solutions that may either be less expensive or provide superior services. As utilities develop better and more sophisticated data monitoring, SCADA, and load monitoring information technology, these systems will need to be designed to provide information, or enable provision of information with minimal effort, to third parties on hourly and sub-hourly feeder and substation, voltage and thermal levels and limits, for example, to level the information playing field so third parties can offer NWAs (as well as a number of other third party uses for that data).

* 1. **Program Administration**

As noted, the program will be administered by a third-party NWA administrator (Third-Party Administrator) retained by and working as a consultant to the Authority, independent of the EDCs and other stakeholders.

The Third-Party Administrator may itself have expertise in distribution engineering, may retain such expertise, or PURA may separately retain distribution engineering expertise to work with the NWA administrator in reviewing EDC distribution engineering, plans, all projects and submissions for distribution system upgrades over $500,000. The Third-Party Administrator will be able to request EDC information and elevate any disagreements to PURA for expeditious resolution.[[8]](#footnote-9)

The Authority expects the Third-Party Administrator will work with the EDCs, the Connecticut Green Bank, DEEP, OCC, other stakeholders, and members of the public on a standardized public format to submit information on planned distribution system upgrades for NWA process consideration and examination with potential NWA providers.

The information which the Authority will expect to be submitted to it annually through the Third-Party Administrator is outlined in Appendix A to the Straw Proposal. This information is necessary for the Third-Party Administrator to evaluate the distribution system upgrades and potential NWA. After the utilities submit this information and the Third-Party Administrator gains experience reviewing it, PURA may expand or narrow the information outlined in Appendix A. The Third-Party Administrator will run a public process to ensure information is shared with Connecticut energy stakeholders and potential NWA bidders to work with the EDCs to identify areas for consideration of NWAs. This represents a transparent opening of the heretofore closed utility distribution planning process.

The Authority expects the EDCs to maintain system information such as feeder and substation hourly and sub-hourly loading and voltage measures in formats that can be readily shared with the Third-Party Administrator and third parties as part of this process. To the extent justified by the EDCs, confidentiality agreements can be signed by third parties and members of the public to assure confidentiality when such requests are legitimate, but the Authority has a preference for a public, open process when possible given the increasing level of public interest in Connecticut’s electricity grid.

When a likely candidate for an NWA project is identified (i.e., a distribution need that could be met with an NWA), the Authority expects the Third-Party Administrator to determine if timing of the need allows for gathering more information. If so, the Authority expects the Third-Party Administrator to issue one or more Requests for Information (RFIs) to the EDCs on the likely projects and parameters and then simultaneously or sequentially to interested bidders. If the utility is a potential implementor of an aspect of the NWA or related distribution or transmission upgrades related to the violation that the NWA may address, the RFI process and responses should be open to other potential bidders, stakeholders and members of the public who complete any necessary NDAs or CEII agreements on forms approvals by the Authority. That said, the Third-Party Administrators, EDCs and other parties shall endeavor to maintain as much information as public as possible. An ordinary distribution system NWA opportunity does not necessarily involve any EDC business confidentiality or CEII issues and the Authority do not mean to suggest that to be the case.

RFIs themselves can be useful for informing both the Third-Party Administrator and the process of how to hone effective RFPs for NWA projections to meet distribution system needs, save ratepayers money, and identify technical, reliability and project permutations between traditional EDC plant and NWAs. The Authority would expect that a given RFI would gather information on what resource types and combinations of resources may meet particular distribution system needs, integration of resources with the distribution system, and operations needs for NWAs. For these reasons, the Authority expects the Third-Party Administrator to issue RFIs related to NWA design, integration with the distribution system, and potential bidder structures. The circumstances that may justify jumping from an NWA need identification directly to an RFP would involve imminent timing to address a distribution system need on short notice from the LDCs.

* 1. **Suitability Criteria for NWA Solutions Expected to Evolve with Experience**

While the EDC’s maintain in their comments that the utilities must initially control the identification of suitable NWAs[[9]](#footnote-10) before the Authority, DEEP, OCC or stakeholders are aware of distribution needs presenting an opportunity for an NWA, the Authority finds this insistence on utility control to be contrary to PURA’s obligation to ratepayers to review EDC costs for prudence and necessity.

As noted previously, the Authority finds that when DERs can provide load flexibility and deliver load reduction or distributed generation to meet reliability needs. Ensuring that the best suite of DERs to address any distribution system need are considered, and ultimately selected, requires an open, transparent process starting with identification of violations, service upgrades and improvements to the grid system as they identify new distribution system investments.

While projected thermal violations, voltage violations, and substation expansions, often associated with load growth scenarios, have been subject to NWAs to date in other jurisdictions, the Authority is reluctant to establish narrow suitability criteria that might inadvertently eliminate the ability of EDCs and stakeholders to propose innovative NWAs to address projected utility system needs more efficiently than traditional solutions. For this reason, PURA directs that the independent NWA Administrator and associated stakeholders proceed to review all distribution system investments over $500,000 per circuit and per substation for the project, whether spread over one or more years. This will require regular monthly meetings of an NWA stakeholder group led by the Third-Party Administrator. It will also require submissions by the EDCs annually in advance of each meeting of planned distribution system upgrades, emerging violations, projected issues and system needs five to ten years hence.

As the EDCs perform system analysis and update needs for future years, the Authority anticipates submission to the NWA process on emerging violations, identified distribution system investments over $500,000 per circuit and per substation and projected system needs five and ten years hence. In sum, this information will be updated at least annually on a system-wide basis to be filed with the Third-Party Administrator and shared with the NWA stakeholders. It will be reviewed in a series of meetings, at least monthly.

While the Authority is not mandating suitability criteria at this early stage in development of the NWA program, the Authority does expect NWAs to be evaluated on a comparable financial and cost basis to traditional system upgrades. NWA cost deferrals that are assumed to disappear after year 10 is an example of an assumption that unduly favors a traditional distribution plant capital upgrade. Due to successes with Connecticut energy efficiency investments, it is quite conceivable that an NWA project provides sufficient time for the traditional distribution plant capital need to be eliminated in part or entirely.

* 1. **NWA Screening Process Among the EDCs and Stakeholders**

Screening will occur for all distribution system investments over $500,000 by the Third-Party Administrator’s facilitation of the public, stakeholder process. An identification of any distribution system investments over $500,000 will be submitted at least annually to the Authority and the Third-Party Administrator who will review the projects with the EDCs and stakeholders. The EDCs will also annually submit the information contained in Appendix B to this NWA Program Document.

As to the submission of system upgrades, the EDCs will identify the year of need, the violation(s) driving the need, the size and type of need and the EDC’s preferred or tentative solutions together with a range of OPEX and CAPEX costs associated with each preferred or tentative solution. When there is a capacity and/or duration (number of hours per year, duration of each event) need to resolve the violation of need, the utility will specify that capacity needed, hours of violation or projected violation, and duration of violation or projected violations by event and year.

The Authority anticipates that the process of regular NWA meetings convened by the Third-Party Administrator will proceed from need identification to need solution(s). Those solutions may be (1) through an NWA project or projects, (2) through traditional distribution system upgrades, or (3) through a combination of an NWA approach with traditional distribution system upgrades. The overall guiding principle will be to identify value for Connecticut ratepayers and societal benefits over the long term. Experience in other states[[10]](#footnote-11) has shown that even where an NWA solution does not completely meet an identified need, NWA solutions can result in cost savings and smaller traditional distribution system upgrades than would have been needed absent an NWA. NWA projects that propose superior benefits to traditional distribution system upgrades may be considered even at similar costs. Examples of such superior public benefits for ratepayers may be NWA improvements as part of a public safety microgrid project that would provide backup power for public safety, emergency or medical facilities when the grid is down due to extreme storm, cyber event or terrorists events, etc. Other than superior public benefits for ratepayers, the Authority expects the Third-Party Administrator would strive to identify cost savings or service and reliability benefits for ratepayers from NWA projects. The Authority also notes that it is likely that NWA projects may involve aspects of upgrades to traditional distribution systems by the utilities as well.

All stakeholder reviewed screenings for NWAs will be submitted to PURA for review by the Third-Party Administrator upon a joint motion of the stakeholders reviewing it. The Authority expects to receive at least quarterly updates from the Third-Party Administrator on status of review of distribution system investments, NWA opportunities, the quality of information provided by the EDCs, and interest of third parties in all NWA opportunities. The updates may be in person public meetings whereby the Third-Party Administrator updates the Authority on status each of the broad items enumerated herein.

* 1. **Competitive Solicitation Process**

When an NWA Solution may be feasible in the judgement of the independent Third-Party Administrator, the Third-Party Administrator may prepare a solicitation RFP for a competitive solicitation. The Third-Party Administrator will share the draft solicitation with the EDC involved for comment and attempt to refine the needs cooperatively with the EDC. The EDC shall also cooperate in good faith with the Third-Party Administrator to refine any NWA RFP.

As noted above, the Third-Party Administrator is encouraged to issue RFIs to gather additional information from EDCs, alternative energy companies, potential bidders, and other stakeholders. Such additional information can involve technical needs to safely and reliability address a potential violation, information on the potential violation, or types of NWA elements and combinations of technologies, reserves and redundancies required. This list of RFI requests is not exclusive or limited to these items. Other NWA processes have found RFIs to be useful prior to issuance of an RFP.

The Third-Party Administrator shall issue an NWA RFP and evaluate the resulting proposal. In the judgment of the Third-Party Administrator, it may involve the EDC in reviewing technical (but not pricing) aspects of proposed solutions. If the EDC is bidding on the project or has an affiliate bidding on the NWA project, the Authority would not expect the Third-Party Administrator to involve the EDC in the evaluation.

The Third-Party Administrator may make recommendations to PURA on procurement of NWAs. The Third-Party Administrator recommendations will include application of the existing Conservation and Load Management (C&LM) plan and ratepayer impact tests applied in Connecticut as well as benefit-cost framework elements addressed below in Section F. The Third-Party Administrator will provide a technical feasibility analysis, compare the NWA to the traditional alternatives including whether the NWA would provide at least the same level of reliability and resilience; and a narrative comparing the society costs/benefits of the NWA, and how it aligns with Connecticut’s policy and PURA’s regulatory objectives.

PURA would then conduct a review process regarding feasibility, costs, alternatives, reliability, and resilience benefits of the proposed solution(s) and the comparison of the alternatives through a docketed proceeding. PURA would either adopt the NWA recommendation of the Third-Party Administrator and order the EDCs to enter into a contract to implement the NWA, the contract to be approved by PURA, or decline to adopt an NWA.

* 1. **BCA Framework Elements**

In evaluating a proposal, the Third-party Administrator will focus on feasibility, cost effectiveness, and other benefits including reliability and resilience. Costs and benefits would be considering following current BCA framework elements as recognized by DEEP, PURA, and the Connecticut Green Bank. As noted by DEEP in its response to RSR-2, the latest description of benefit-cost screening of the C&LM plan is contained in Chapter Three of the 2021 Plan Update. The benefits included for the primary utility cost test for electricity savings include:

* Electric energy savings and energy demand-reduction induced price effects (DRIPE);
* Electric wholesale generation capacity and capacity DRIPE;
* Avoided T&D costs in Connecticut based on 2017 studies from Eversource and UI;
* Avoided regional transmission costs from the ISO-NE Pooled Transmission Facilities tariff; and
* A monetized benefit estimate for reliability.

In addition, the total resource cost test includes additional benefits for non-electric fuel savings, avoided water costs, and emissions benefits. The below chart from the 2021 Plan Update to the 2019-2021 Conservation & Load Management Plan[[11]](#footnote-12) shows how the valuation of different elements occurs.



Of course, in the case of avoided distribution costs for a non-wires alternative, costs that are specific to the relevant distribution project must be substituted for generic system-wide distribution avoided costs.

In the context of the C&LM plan, the utility cost test has historically been the primary cost test. The Authority observes that DEEP has recently specified inclusion of non-energy benefits for the income-eligible program due to a statutory change as well as all energy savings.[[12]](#footnote-13) In light of these changes as well as the importance of Connecticut policies to reduce harmful criteria air and climate pollution, use of the more expansive total resource cost test, along with the utility cost test, is appropriate for NWAs.[[13]](#footnote-14) The Authority directs the Third-party Administrator to use this framework, and specifically the total resource cost test and utility cost test approaches of the 2021 C&LM update and project-specific distribution avoided costs in its evaluation of NWA proposals. Given that NWA proposals will be considered on a case-by-case basis, the application of this BCA framework and any recommended modifications to apply the 2021 C&LM BCA approach to specific NWAs can be examined in each PURA docket evaluating an NWA selection.

PURA recognizes that several commenters recommended a stakeholder process to establish a benefit-cost framework specific to non-wires alternatives. Such a process for NWAs is not proposed here for the following reasons. First, while the benefits of non-wires alternatives have a significant locational element that is not present in some other contexts, the broader revisions of Connecticut’s benefit-cost test approach for energy projects and program evaluation are not unique to this docket and should be considered across programs. Second, such a stakeholder process would necessitate significant time and resource commitments by state agencies, stakeholders, and the utilities that is better spent standing up the more general process for this program. Third, DEEP plays a substantial role in Connecticut’s revisions to BCA processes and methodologies, which the Authority recognizes. As with other elements of the Straw Proposal, comments on this path forward are welcome.

The Authority anticipates any project or solicitations questions in applying this BCA framework to any specific NWA will be addressed by stakeholders in the NWA process with the Third-Party Administrator in any recommendations ultimately subject to PURA review. As experience and practice with a Third-Party Administrator framework accumulates, the Authority may find it advisable to adopt a modified BCA framework for NWAs. Alternatively, DEEP may continue to adapt the benefit-cost tests used for the C&LM plans, which PURA may adopt as DEEP’s approach evolves.

* 1. **NWA Resources that Qualify to be Considered and Use Cases**

PURA does not place limitation on qualifying technology types for NWA projects. Premature limitations may inhibit innovation by EDCs or third-party bidders and development of new options in the marketplace. PURA observes that competition tends to reduce costs and improve service quality leading to technology, service, and business case innovation. For that reason, PURA endorses broader competition to meet ratepayer and customer needs when feasible to provide reliable service.

Innovative proposals may find new technology, service, firmware and software that can provide reliability and resilience benefits that are comparable. Innovative proposals may involve customer benefits and resilience offerings that traditional distribution solutions do not. The Authority thus clearly states that it expects how it evaluates innovative proposals to include evaluation of traditional modes of evaluating reliability and resilience as may occur in particular proposals. The Authority expects that the Third-Party Administrator will build in reliability considerations, consider reliability criteria specified to consider NWAs and address those issues in any recommendations to the Authority.

NWA technologies that can satisfy the inter-related reliability, redundancy, and reserve needs of various grid elements (as set forth by the Third-Party Administrator in consultation with the EDCs and other stakeholders and determined by PURA) may be considered for NWAs. The list of qualifying technologies categories and types for NWA projects includes but are not limited to:

## Passive DERs including energy efficiency to reduce load.

## Active DERs such as electric batteries to provide load serving, voltage regulation, frequency regulation or other grid functions.

## Demand response.

## Connecticut Class I and Class III resources.

## Behind the Meter (BTW) technologies whether aggregated or not, and

## Front of the Meter (FTM) technologies whether aggregated or not.

The focal point of any inquiry for any NWA resource portfolio – a portfolio may be preferred to a single resource – is whether it meets the identified system needs and what additional benefits it might offer customers or the public.

In meeting needs, a margin for performance for particular resources may be advisable to build into any NWA a conservative engineering factor just as such factors are built into the current grid. Depending on the reliability need, redundancy of resource or combinations of resources with different performance and operational characteristics, built-in reserves margins, and other design features may be advisable to provide the desired or superior grid performance as well as grid resilience and customer resilience value. The New York Brooklyn-Queens project did exactly this in procuring DERs in anticipation that DER performance may fall short of expectations. This is consistent with aspects of current distribution system planning, where “firm” substation capacity can be thought of as the load carrying capability of the relevant equipment if the largest transformer fails. This type of planning carries extra distribution plant carrying costs in order to ensure reliability.

Use cases for each NWA may be different. While some use cases may emerge as more feasible, practical, or economic to pursue through NWAs in the long run, the Authority expects these use cases to be developed through program experience initially. For this reason, PURA does not propose to limit allowable use cases but rather to invite innovative and creative proposals to provide ratepayers savings and/or superior customer and grid services. Initially, as Connecticut develops this program, PURA staff would work with the Third-Party Program Administrator to advise PURA regarding the Third-Party Administrator’s recommendations on weighing the types and magnitude of benefits provided by proposed NWAs in the RFP process.

PURA does accept the comment of the New England Clean Energy Council and Renew Northeast to allow for use case stacking. While the primary use case may be distribution system reliability or another use, a secondary use case to provide customer benefits behind the meter or participate in the wholesale markets through frequency regulation, for example for a battery, is allowable and may be desirable to reduce the costs of different resources in a portfolio or provide an enhanced reserve or resource margin. Examining the complementary nature of different use cases and the ability of resources to meet those use cases under anticipated operational scenarios would be expected when resources with different “stacked” use cases are considered.

In fact, since distributed resources can provide multiple retail, wholesale, and customer level functions in different use cases, the Authority views this resource stacking as increasingly necessary and desirable. A new electric vehicle (EV) pickup truck or SUV will have a battery capacity capable of providing substantial NWA support, operating in the wholesale markets under an aggregation in Order 2222, or providing several days of backup power for a customer residence. Those use cases are more complementary than not and may be combined to support NWAs, wholesale market functions, and customer value.[[14]](#footnote-15)

The Third-Party Administrator may select one or more NWAs that provide net positive benefits to ratepayers that meets the specified need(s). The Authority declines to prescribe quantifications or qualitative factors in use cases for benefits the Third-Party Administrator may consider or use to select one NWA over another so long as any NWA selected provides net present value positive benefits compared with the traditional solution using the benefits and cost tests employed in the CLM plan while providing for reliable service.

* 1. **Performance Criteria**

In evaluating any NWA, the Third-Party Administrator shall identify the grid need(s) to be addressed, any other benefits, costs factors for capital, and operational aspects of all alternatives considered in the utility’s(ies’) traditional set of grid additions. The RFP, selection and recommendations of solutions to PURA shall include an evaluation of how different alternatives meet grid needs. The grid needs will be refined from the needs identified by the EDCs in the EDCs’ annual filing of distribution system needs by elements specified in Appendix B and specifically each distribution system improvement of $500,000.

Performance criteria to ensure delivery of anticipated grid benefits, within anticipated cost ranges will be identified with each NWA solution recommended by the Third-Party Administrator to PURA.

For additional operational, grid, customer or other benefits, the Third-Party Administrator shall also propose performance criteria to evaluate NWA Solution success. Together with operational, implementation, and other performance criteria, any cost criteria important to track will also be identified by the Third-Party Administrator and provided to PURA for further review and development.

As with the cost-benefit and use case approach above, as Connecticut develops this program, PURA staff would work with the Third-Party Program Administrator to advise PURA on the types and magnitude of benefits provided by proposed NWAs in the RFP process. The Program Administrator may select one or more NWAs that provide net positive benefits to ratepayers that meets the specified need(s) and other criteria consistent with the benefits and cost test employed in the C&LM plan. The Authority declines to prescribe performance criteria beyond mandating that the Third-Party Administrator may consider or use to select one NWA over another with criteria for each NWA project selected to ensure any NWA selected provides net present value positive benefits compared with the traditional solution using the benefits and cost tests employed in the C&LM plan.

* 1. **Measurement and Verification Plan Requirements**

Each NWA that is procured will have performance criteria specified in the RFP and may be further developed through the Third-Party Administrator process, ultimately to be approved by PURA as described above. The performance criteria will be refined to development, deployment, implementation, operational, and reporting metrics. Those metrics will be quantifiable with precise data to be collected and specified formulas to be applied to the extent practical in PURA’s approvals. The Third-Party Administrator may make recommendations for specific performance criteria for each recommended NWA.

If some metrics cannot be quantified, qualitative metrics may be considered. For example, one such qualitative metric could be end-user experience where behind-the-meter (BTM) technologies participate in an NWA and also provide end-user benefits. The Authority recognizes that measures and metrics such as end-user benefits and experience may involve both quantified metrics and qualitative measures: a BTM battery installation available for back-up or storm outage power might have minutes of back-up power to provide as a specified (quantified) measure while surveyed satisfaction with installation, reliability and flexibility may be a (qualitative assessment) measure.

After an NWA solution is approved by PURA for implementation, the Third-Party Administrator, in consultation with the EDCs, shall develop an evaluation, measurement and verification (EM&V) plan that is specific to each NWA. After consulting with the EDCs, public stakeholders, and the entity carrying out the NWA, the Third-Party Administrator shall submit an EM&V plan to the Authority that contains the following elements:

* 1. NWA system costs projected and actual, including CAPEX and OPEX, any soft costs such as permitting, lease payments, interconnection and utility upgrade costs;
  2. Projected and actual commercial operation data;
  3. Projected and actual run-time, durations for the NWA elements, by element and together on an hourly or sub-hourly basis;
  4. Type(s) and operational data on energy management systems, controls and/or dispatch associated with the NWA;
  5. Financial data on project return, capital in rate base or investor by third parties, cost recovery (may be filed as confidential data by third parties);
  6. For projects involving customer participation, information on customer participation and customer value measures and metrics including measures of customer resilience and value when the grid is down as applicable;
  7. Any revenue including wholesale market and utility revenue requirement revenues to the project;
  8. Reporting measures and metrics on the distribution system need addressed by the project and evaluation of meeting that need;
  9. Peak demand reductions for each event;
  10. Any zonal capacity or transmission reductions under the ISO-NE tariff;
  11. Public health benefits;
  12. Reductions or increases in emissions of NOx, PM 2.5, and CO2;
  13. Any impacts on distributed generation hosting capacity;
  14. Measure of power quality such as voltage within allowable limitations, SARFI70, Total Harmonic Distortion, Total Demand Distortion; and
  15. Reliability metrics for the circuit for tracking by five years prior to the NWA through the NWA for SAIDI, SAIFI, CAIDI, excluding and including major storm events.[[15]](#footnote-16)

All EM&V plans shall be approved by the Authority in a proceeding simultaneously to or following approval of the NWA project(s). Thereafter, the EDCs shall work with the Third-Party Administrator in consultation with DEEP and OCC to execute the EM&V plan for each NWA. While a standard format for an EM&V plan for NWAs may eventually be established, the Authority anticipates developing best practices for NWA EM&V through learning and evolution of in the initial NWA projects.

* 1. **Ownership Models**

In support of a vigorous and fair competitive process, EDC ownership of NWA solutions shall only be allowed in the following circumstances:[[16]](#footnote-17)

1. Procurement of an NWA has been solicited to meet a system need, and the EDC has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or fail to satisfy the benefit to cost analysis compared to a traditional utility infrastructure alternative;
2. A project consists of energy storage integrated into distribution system architecture;
3. A project will enable low- or moderate-income residential customers to benefit from DERs where markets are not likely to satisfy the need based on the results of a Third-Party Administrator or utility solicitation; and
4. A project is being sponsored for demonstration purposes by a utility.
   1. **Market Engagement Strategies**

Transparency is critical to development of a competitive market for NWA providers at all stages including initial distribution system need identification and NWA suitability screening. Competitive companies need to have confidence in the process to invest their own resources to develop competitive bids. An open NWA process that allows NWA providers to access information on potential NWAs concurrently with potential utility-affiliates is important for the Third-Party Administrator.

The Northeast Clean Energy Council and RENEW Northeast pointed to the importance of information sharing to facilitate well-designed RFP solutions:

Respondents require clarity on the solution being sought, the characteristics of the project need and surrounding load, the criteria by which a project will be evaluated, and the deadline for project completion. The more information that is available to potential respondents, the more well-designed a solution can be.[[17]](#footnote-18)

For these reasons, the Authority views a transparent process communicating the solution(s) being sought, the project need(s) and surrounding load, and criteria for evaluation as well as project completion as a critically important market engagement strategy.

NWA providers must be able to be engaged in all aspects of the process from identification of distribution system projects to scoping with the Third-Party Administrator. NWA providers shall be allowed to sign NDA and CEII Agreement to have the same access to project identification and scoping data and information as the Third-Party Administrator. Ideally, NWA providers shall be allowed the same access as any EDCs bidding on those projects, which necessitates the open initial process to needs identification discussed herein.

Indeed, where alternatives to traditional EDC distribution lines, substations and other costs are available, the EDC’s “traditional solutions” sets the baseline solution to beat in pricing and/or service quality. The NECEC and RENEW comments underlie this point as well, emphasizing that:

. . . the NWA Framework must ensure that the EDCs’ solicitations provide for third-party solutions, and the EDCs are incented to choose the most competitive and reliable solution regardless of who owns the NWA resources.[[18]](#footnote-19)

The Authority acknowledges and adopts these two points in NECEC’s and RENEW’s comments on the importance of competition and openness to third-party solutions facilitated with thorough transparency. The EDCs and third parties may both have legitimate business confidentiality needs. While the Authority intends to establish an open and transparent process to share information on distribution system needs and costs with third parties and the public, it also recognizes that there are proprietary technology and competitiveness concerns. The Authority expects there to be a confidential process to identify and vet claims of business confidentiality and proprietary information that may involve Third-Party Administrator referral of confidentiality request to the Authority in an RFI or RFP process. Moreover, once a final project is selected and a contract is negotiated, it may be appropriate to qualify proprietary technology performance and pricing as confidential, if necessary, to procure deployment of such technologies in a Connecticut NWA project.

* 1. **Equal Playing Field for Ratepayers to Keep Costs Down**

The goal of reducing ratepayer costs necessitates comparing bid NWA expenses against likely EDC and ultimate customer expenses for a traditional utility solution. For purposes of the Third-Party Administrator comparisons and the Authority’s consideration, the costs that ratepayers would be most likely to incur in the revenue requirement will be used for an accurate dollar-to-dollar comparison of alternatives.

In making the calculation of potential savings for ratepayers in costs to be avoided through an NWA, the traditional utility solution may be calculated from the year of implementation that the Authority determines is reasonable to initiate when the traditional solution would be added to rate base. Because ratepayers typically pay for all utility revenue, including rates of return, the calculation of EDC capital and operational expenses savings for customers may include the EDC’s approved rate of return on capital components, any requested rate of return pending, any amortization/depreciation expense, and operation expenses approved or pending as if the traditional solution were included in EDC rate base.

The possible ratepayer savings are substantial given the likelihood that most NWAs will be operation expenses rather than capital expenses and therefore not subject to utility rate of return, amortization, and depreciation expense each year.

* 1. **Participation of NWA Resources in Other Programs and Markets[[19]](#footnote-20)**

The ability of NWA resources to participate in other markets and programs is important in realizing their value at each level of the grid. Some DERs provide services, in addition to value as NWAs, to distribution infrastructure.

To realize the value that may exist from multiple value streams, designing NWAs to procure distribution value for EDC functions and EDC ratepayers while also allowing for other uses that are complementary and non-exclusive, will reduce the costs of these NWA solutions and improve the potential customer value.

For example, in Vermont, Green Mountain Power’s battery programs provide distribution system support as well as provide a power supply hedging resource for GMP and provide customers with back-up power support during storm outages.[[20]](#footnote-21) Each use is non-exclusive, distribution system support and supply hedging support for GMP’s operations and economics, reduce costs and therefore also assist ratepayers in grid reliability and cost-reductions. The same batteries provide the customer with storm back-up power -- a BTM customer benefit that traditional distribution infrastructure cannot. Complementary uses should be identified and maximized to the extent consistent with the primary purpose of the NWA. Indeed, it is possible that revenue and savings from complementary uses such as capacity or transmission peak reductions may exceed distribution system savings. The Authority sets no minimal distribution system savings figure or percentage so long as the benefits overall exceed costs.

ISO-NE is now finalizing its FERC Order 841 compliance for integration of batteries into its markets. And ISO-NE is proceeding with implementation of FERC Order 2222 on DER Aggregation. Both FERC mandates will potentially allow for more NWA resource value streams that may make NWAs both less expensive and able to recognize multiple values. FERC Order 2222 is explicit about DERs ability to participate in multiple markets.

To the extent that multiple values can be realized while maintaining the integrity of each function, the cost of realizing each value is reduced and the potential to enhance customer service grows.

1. **UTILITY COST RECOVERY FOR NWA SOLUTIONS**

When the Authority approves a Third-Party Administrator recommendation for an NWA, the EDC will be able to recover all reasonable and prudently incurred NWA costs. The EDC will not be at risk for NWA provider cost overruns and contractual provisions will be designed to avoid such overruns. The EDCs will only be responsible for their own implementation of the NWA solution and will recover their costs as operational expenses.

Because the EDCs will be allowed to bid on NWA solutions, they will have the same opportunities as other RFP respondents to make a profit on a winning RFP response. Allowing the utility itself to recovery an ROE on the NWA costs would perhaps constitute a layer of double recovery of profit and utility costs that could create perverse incentives to shift costs and cost accounting. In any event, the possibility of double-recoveries will always need to be monitored carefully under any NWA structure. For these reasons, the Authority determines that any costs for NWA shall be recovered as operational costs without any ROE incentive but subject to utilities earnings for ratepayers’ costs savings sharing and consumer benefit incentives discussed below.

However, in the event that an NWA does not provide a viable alternative to the proposed or preferred traditional solution, the EDCs will be allowed to rate base the prudently incurred costs associated with the traditional solution deployed consistent with the Authority’s past practices.

1. **UTILITY INCENTIVES TO ACHIEVE CUSTOMER SAVINGS**

When an NWA solution is preferred to traditional utility solution(s), and the EDC has cooperated in development of the opportunity by sharing information and implementation, the EDC may be awarded a shared savings performance incentive of up to one quarter of the projected net savings achieved in comparison to the traditional utility solution.

This customer savings incentive designed to share with utilities will act as a cap on the utility performance incentive for both customer savings and superior grid and customer benefits addressed in Section VI below. The Authority finds that utility implementation incentives of up to one quarter of the project net customer savings shall be shared for several reasons: (1) this customer savings incentive is focusing primarily on customer savings; (2) it provides the EDCs and all stakeholders with a strong signal to look for NWAs that provide cost savings; and (3) it is more conservative than other jurisdictions. On that last point, we note that New York allows a 30% sharing of net benefits[[21]](#footnote-22) (as distinct from net consumer savings). In this regard, the Authority suggests a more conservative test because either the consumer savings incentive or the customer benefit incentive would both be capped at 25% of customer savings. This structure hems the Authority’s approach closely to pursuing customer savings at the same time it advances Connecticut’s grid modernization through NWA and other initiatives.

In making the calculation of actual savings for customers, the traditional utility solution may be calculated from the year of implementation that the Authority determines is reasonable to initiate when the traditional solution would be added to rate base. The calculation of actual savings for customers may include the utility’s approved rate of return on capital components, amortization/depreciation expense, and operational expenses as if the traditional solution were included in utility rate base to produce a counter-factual baseline as if the NWA had not gone forward that is used to calculate the customer savings for the NWA.

The Authority requests that the Third-Party Administrator calculate consumer savings compared to traditional utility plant costs as well as net grid and customer benefits below in Section VI. Customer savings may include savings for any costs -- whether distribution system, ISO-NE transmission or capacity allocations or market savings. It is important for the Authority to consider both customer savings compared to a distribution system plant addition in a business as usual case, thus the customer savings, and the total grid and customer benefits, which may well be a broader set of considerations than customer costs.

1. **UTILITY INCENTIVES TO ACHIEVE SUPERIOR GRID AND CUSTOMER BENEFITS**

Where an NWA solution offers EDC, grid, wholesale market, ISO-NE expenses, or customer benefits beyond a dollar savings, the Third-Party Administrator may attempt to quantify the value of those additional savings. Such additional savings may involve resiliency, reliability, environmental, or other attributions that a traditional EDC solution could not achieve.

The Authority may approve EDC performance incentives for up to half the calculated value of additional, superior grid, and/or customer benefits provided that the total grid and customer benefit incentives shall not exceed the customer savings incentives described in Section V above. The benefit performance incentive may be in in lieu of a customer savings incentive as discussed in Section V based on the particular recommendations of the Third-Party Administrator and the Authority’s view of the benefits, costs and risk allocation, as well as the party best situated to manage the risks for implementation and project management. However, 50% of net customer benefits remains capped at 25% of customer savings as described in Section V above. For this reason, the Authority approves up to 50% of net customer benefits, mainly because this incentive may not exceed 25% of customer savings compared to traditional utility infrastructure and traditional utility returns.

To earn a utility incentive, the superior grid benefits and customer benefits must be quantified and accepted by PURA in establishing the NWA. The EDC is entitled to clear guidance on what incentives it can earn and the ratepayers are entitled to clear quantifications to show how those incentives that ratepayers will pay are earned by an EDC.

1. **SUMMARY**

The Authority hereby concludes that encouraging NWA consideration through an independent Third-Party Administrator is in the best interests of Connecticut’s EDC customers. The Third-Party Administrator would be selected by PURA to run a regular review of EDC system distribution needs to identify and consider NWA opportunities through an open, transparent stakeholder process. When appropriate, the Third-Party Administrator will be authorized to solicit NWA proposals, fully evaluate those proposals, and make consensus or its own recommendations to the Authority, which the Authority will consider through a distinct docketed proceeding. The Authority anticipates a transparent process throughout, aided by the good faith participation and active engagement of the EDCs, along with the participation and consultation of DEEP, OCC, and other interested stakeholders.

**Appendix A**

NWA solutions utilized in other jurisdictions

This appendix provides a brief overview of the most frequently cited non-wires alternative projects in the U.S. These projects include a mix of non-wires alternatives on the transmission and distribution system. Many of the projects listed here are in the Smart Electric Power Alliance report, which selected 10 NWA case studies based upon their applicability to other utilities, whether the challenges and lessons learned had broad industry applicability, and cross-sectional representation of geographic area, size and project type.

Examples of NWA solutions that have proven feasible and cost-effective:

* The Consolidated Edison Brooklyn-Queens Demand Management project, started in operation in 2016, definitively put to rest any debate over whether NWA solutions are feasible. The Brooklyn-Queens project also put to rest any debate over whether NWAs can save ratepayers substantial amounts. In that New York case, ConEd working with the New York DPS pursuant to NY DPS orders solicited multiple procurements of DERs to reduce and shift load sufficiently to avoid investment of over $1 billion in a new substation. The BQDM project is one of the largest NWA projects in the U.S, with close to 52 MW of traditional customer-side options (41MW) and non-traditional utility-side (11MW) resources, including fuel cells; combined heat and power (CHP); energy efficiency (EE) projects with the city and state; battery storage; solar photovoltaic (PV) systems; and conservation voltage optimization (CVO). BDQM met the original program objectives, and has since been extended to meet additional load reduction needs. Savings from the measures deployed in the NAW delayed the buildout of a new substation, leading ConEd to further delay the buildout, and potentially permanently defer the new substation.[[22]](#footnote-23)
* The non-wires alternative project on Maine’s Boothbay peninsula avoided the need for a new 115 kV transmission line with suite of much less expensive DERs between 2013 and 2017. DERs included energy efficient commercial lighting, energy storage, and rooftop solar PV systems, which helped to mitigate the impacts of seasonal businesses. In total, 1.8 kW of non-transmission alternatives were deployed between late 2013 and early 2015, and included the first large-scale, 500 kW, battery storage unit in Maine, a 500 kW diesel fueled back-up generator, 243 kW of efficient lighting and air conditioning, 308 kW of solar PV, 224 kW of peak load shifting, and 29 kW of demand response units.[[23]](#footnote-24) The 115 kV transmission line was subsequently cancelled.
* Eversource utilities briefed the re07 workgroup on its non-wires alternative project on the Cape in its Massachusetts service territory that likewise is avoiding the need for a new transmission line in an area where siting would pose difficulties.
* Arizona Public Services 2 MW, 8 MWh Battery Electric Storage System in Punkin Center Arizona designed for 21 kV feeder-level peak shaving.[[24]](#footnote-25) The project started in 2018 and has successfully provided feeder peak shaving with high reliability. The project has the potential to provide a long-term deferment of wires investment and generation. The BESS was considered the least-cost solution rather than rebuilding 17 miles of power lines over rough terrain.[[25]](#footnote-26)
* Southern California Edison’s 2.4 MW, 3.9 MWh Battery Electric Storage System in Orange California, which has been active since 2015, deferred a distribution system upgrade, and mitigated a substation transformer overload, thus meeting the original objectives of the project. The BESS is also capable of other control odes, including reactive power dispatch for voltage regulation.[[26]](#footnote-27)
* National Grid created a NWA pilot Tiverton and Little Compton Rhode Island in 2012, using geographically-targeted energy efficiency and demand response.[[27]](#footnote-28) The goal was a 1 MW load-offset goal, which was not reached, but it did successfully defer a $2.9 million feeder project.[[28]](#footnote-29)
* Consumers Energy in Michigan created the Schwartz Creek Energy Savers Club to address a distribution grid constraint utilizing energy efficiency and demand response. The goal was to reduce load requirements below 80% maximum summer capacity in order to defer a $1.1 million upgrade of infrastructure. The project needed to reduce load by 1.4 MW by the end of 2018, or 1.6 MW by the end of 2019. The program met almost the entire 2018 savings target of 1.4 MW. Ultimately anticipated load growth at the target substation did not materialize, so no upgrades were needed.[[29]](#footnote-30)
* Central Hudson in NY state created a Peak Perks Targeted Demand Management Program as part of the NY REV initiative. The program, which started in 2016, was designed to defer the need for new infrastructure in three zones for 5-10 years. In the first year, the utility exceeded the 5.3 MW load reduction target by achieving 5.9 MW of load reduction. It also achieved it’s 50% load reduction target of 8.0 MW in October 2017.[[30]](#footnote-31)
* Vermont has a system planning committee (known as VSPC) created in 2007 which is a statewide collaborative process for addressing electric grid reliability planning. The goal of the process is to ensure full, fair and timely consideration of all options to solve grid reliability issues. Each identified reliability issue on the electric grid must be screened to determine whether a potential exists to resolve the issue with some configuration of energy efficiency, demand response and generation, or a hybrid solutions approach. If a potential exists, the affected utilities then conduct a full analysis to determine whether some configuration of alternatives is cost effective.[[31]](#footnote-32) The analysis also contains a geotargeting screening framework to determine where installing additional generation may provide sufficient benefit to reduce or eliminate the constraint without a poles-and-wires solution. Due to declining load growth, few reliability constraints have been identified that would utilize the screening process.

**Appendix B**

Baseline Distribution System, Financial, and DER Deployment Data and Information

To be submitted by the EDC to the NWA process

**System Data**

1. Modeling and power flow software currently used (name and vintage)
   1. Is software capable of probabilistic or Monte Carlo method forecasting?
   2. Is there system interoperability or links between modeling software and other  
      existing data platforms (e.g. Meter Data Management System (MDMS),  
      Supervisory Control and Data Acquisition (SCADA), PI (Historian type  
      database), Geographic Information System (GIS), Esri, etc.?
   3. Are there planned software deployments that will impact 1(a) and (b)?
   4. GIS system information, including how up to date the system is, the method and frequency for updating the data, how the data is used in planning, the methodology for validating the data, and operations models utilizing that data hosting capacity analysis.
2. Annual peak load growth at the most granular level available i.e. the circuit,  
   substation, town, operating area, or system level for each of the past five  
   years and forecasted load growth for each of the next ten years
3. Distribution system load forecast for all circuits, including circuit capacity, Including historic loading, both maximum peak day and minimum day, for the past three years, including projected new loading, and projected Distributed Energy Resources (“DER”) impacts
4. Number of substations (transmission to distribution or sub-transmission to  
   distribution) which feed only distribution level customers
   1. Number and Percentage that have no remote monitoring at the feeder level
   2. Number and Percentage that have more detailed remote monitoring but no control
   3. Number and Percentage that have detailed remote monitoring and control
   4. Any planned additions to enhance 4 (a) and (b)
5. Number of distribution substations (transmission to sub-transmission supply) whose circuits feed only the high side of another distribution substation
   1. Number and Percentage that have no remote monitoring at the sub-transmission feeder level
   2. Number and Percentage that have more detailed remote monitoring but no control
   3. Number and Percentage that have detailed remote monitoring and control
   4. Any planned additions to enhance 5 (a) and (b)
6. Number of hybrid distribution substations (transmission to sub-transmission and distribution circuits) that may feed both distribution customers and provide sub-transmission to other distribution substations
   1. Number and Percentage that have no monitoring at the feeder/sub-transmission level
   2. Number and Percentage that have more detailed and complex monitoring but no control
   3. Number and Percentage that have detailed monitoring and control.
   4. Are there planned additions to enhance 6 (a) and (b)
7. Sub-Feeder level visibility and measurement
   1. Distribution Feeder Level: Percentage that have 2 or more remote sensor  
      monitoring on three phase mainline. Indicate type of measurement (voltage,  
      current, etc.) and interval timeframe of data capture
   2. Sub-transmission Feeder Level: Percentage that have 2 or more remote sensor monitoring on three phase mainline. Indicate type of measurement and interval timeframe of data capture
   3. Summary of past (last 3 years) and future (next 3 years) annual installments of sensor devices at the sub-feeder level
8. Number of customer meters with Advanced Metering Infrastructure (“AMI”)/Advanced Meter Reading (“AMR”)/Bridge AMR and those without, planned AMI/AMR/Bridge AMR or collector investments, and overview of existing  
   functionality available
9. Discussion of how the distribution system planning is coordinated with the integrated resource plan (“IRP”) (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans.
10. Discussion of how DER and at what level is considered in load forecasting (distribution feeder, sub-transmission level, distribution substation, bulk distribution substation level, or system-wide) and any expected changes in load forecasting methodology.
11. Discussion if and how the Institute of Electrical and Electronics Engineers (IEEE) Std. 1547-2018 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability).
12. Distribution system annual loss percentage for the prior year (system-wide and by circuit).
13. The maximum hourly coincident monthly load, in kilo-volt-ampere (kVA), for the distribution system, in the past 12 months, as measured at the interface between the transmission and distribution system. Indicate if calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.
14. Total distribution/sub-transmission substation transformer nameplate in kVA.
15. Total distribution/sub-transmission line transformer nameplate in kVA (do not  
    include capacity stated in Item 14).
16. List and map of distribution substation transformers (which feed only distribution level customers) that are:
    1. 90-100% within their normal rating
    2. 80-90% within their normal rating
    3. Less than 80% of their normal rating
17. List and map of sub-transmission substation transformers (whose circuits feed only the high side of another distribution substation) that are:
    1. 90-100% within their normal rating
    2. 80-90% within their normal rating
    3. Less than 80% of their normal rating
18. A list of all distribution feeders broken down by distribution feeders that are:
    1. 90-100% within their normal rating
    2. 80-90% within their normal rating
    3. Less than 80% of their normal rating
19. A list of all sub-transmission feeders broken down by sub-transmission feeders that are:
    1. 90-100% within their normal rating
    2. 80-90% within their normal rating
    3. Less than 80% of their normal rating
20. Total miles of overhead distribution wire:
    1. Three phase
    2. Single phase or two phase
21. Total miles of underground distribution wire:
    1. Three phase
    2. Single phase or two phase
22. Total number of distribution customers:
    1. Distribution Feeder customers
    2. Primary meter customers
23. Utility-wide System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), Customers Interrupted per Interruption (CIII) (IEEE) for the past three years.
24. Ranking of circuits by contribution to SAIDI and SAIFI (IEEE) for the past three years.
25. Information regarding any existing Conservation Voltage applications. (e.g. used to limit only peak loading, or for continuous management of voltage levels across the application area).
26. Number of separately metered electric vehicle charging systems added to the Company's distribution system over each of the past three years.
27. Number of electric vehicle charging systems currently forecasted to be installed in the next three to five years.

**Financial Data**

1. Historical distribution system spending for the past 10-years, in each category:
   1. Age-Related Replacements and Asset Renewal
   2. System Expansion or Upgrades for Capacity
   3. System Expansion or Upgrades for Reliability and Power Quality
   4. New Customer Projects and New Revenue
   5. Grid Modernization and Pilot Projects
   6. Government Mandates
   7. Metering
   8. Other
2. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects.
3. Planned distribution capital projects, including drivers for the project (e.g. see list in Financial Data #1), timeline for improvement, summary of anticipated changes in historic spending.
4. Provide any available cost benefit analysis in which the company evaluated a nontraditional distribution system solution to either a capital or operating upgrade or replacement.

**DER Deployment**

1. Current distributed generation deployment by type (photovoltaic, hydro, wind, etc.), size (≤100 kilowatt (“kW”), 100kW-1 megawatt (“MW”), >1MW), and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.).
2. Information on areas of existing or forecasted high distributed generation penetration; include definition and rationale for what the Company considers “high” penetration; include number and location of known sub-stations and circuits with no or very limited hosting capacity (e.g. for systems 500kW or greater) without significant distributed generation developer investment, and the cause of the limitation.
3. Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where distributed generation installations have caused operational challenges such as power quality, voltage or system overload issues, and associated customer complaints.
4. Provide currently available Hosting Capacity Maps for all measures of Hosting Capacity; information regarding any existing plans the Company has to develop a hosting capacity analysis.
5. Total number of applications and cost spent on distributed generation installation in the prior year (including application review, responding to inquiries, metering,  
   testing, make ready, etc.).
6. Total charges to customers/member installers for DER generation installations, in the prior year (including application, fees, metering, make ready, etc.).
7. Total nameplate kW of distributed generation system which completed interconnection to the system in the prior year.
8. Total number of distributed generation systems which completed interconnection to the system in the prior year.
9. Average interconnection time and average time to complete application review, per application type (Residential Inverter-based <= 20kW, Fast Track, Study Process) as well as number of still pending applications and specific number, if any, of applications still spending after 6 months.

1. The Equitable Modern Grid Framework is outlined in the Interim Decision dated October 2, 2019 in Docket No. 17-12-03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies. [↑](#footnote-ref-2)
2. See, Tr. 8/26/20, pp. 112-122, 129-137. [↑](#footnote-ref-3)
3. For example, see, UI Written Comments, dated November 13, 2020; see also, Eversource Response to RSR-13, Attachment 1, Non-Wires Alternative Framework, Version 2.0, dated February 19, 2021 (filed April 5, 2021). [↑](#footnote-ref-4)
4. Con Edison. (undated) Brooklyn-Queens Demand Management Demand Response Program. Retrieved from: <https://www.coned.com/en/business-partners/business-opportunities/brooklyn-queens-demand-management-demand-response-program> [↑](#footnote-ref-5)
5. GridSolar (2016, January). Final Report Boothbay Sub-Region Smart Grid Reliability Pilot Project. Retrieved from: <https://neep.org/sites/default/files/resources/FINAL_Boothbay%20Pilot%20Report_20160119.pdf> [↑](#footnote-ref-6)
6. Chew, B., Myers, E., Adolf, T., Thomas, E. (2018, November). Non-Wires Alternatives: Case Studies from Leading U.S. Projects. E4theFuture, PLMA, SEPA. Retrieved from: <https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/>, pp. 53-55. [↑](#footnote-ref-7)
7. Specifically, in the 2018 Comprehensive Energy Strategy (CES), DEEP recommended that “PURA should explore the feasibility of requiring the EDCs to conduct an alternatives analysis in distribution-system planning.” The 2018 CES further elaborated that “[a]ny such analysis should open and transparent and should explore the role that third parties could play in distribution system planning while simultaneously maximizing ratepayer savings.” [↑](#footnote-ref-8)
8. As with the Third-Party Administrator and third parties, as necessary and consistent with law, any independent NWA distribution engineer may need to execute non-disclosure agreements (NDA’s) and confidential energy infrastructure information (CEII) agreements to review EDC’s projections of distribution engineering, any data requested, data on violations, projected needs and violations, and EDC proposed solutions. [↑](#footnote-ref-9)
9. Eversource, Draft NWA Framework, Version 2.0, 2021; UI Written Comments, Dock. No. 17-12-03RE07, Nov. 13, 2020. [↑](#footnote-ref-10)
10. See, for example, Maine, Rhode Island, and Michigan examples as cited in Appendix A. [↑](#footnote-ref-11)
11. Submitted by DEEP as Attachment 5 to RSR-2. [↑](#footnote-ref-12)
12. DEEP Response to RSR-2. [↑](#footnote-ref-13)
13. PURA approved a similar consideration of multiple cost-benefit tests, including an expansion of the non-energy benefits included in such tests in Docket No. 17-12-03RE03, PURA Investigation into Distribution System Planning of the Electric Distribution Companies –Electric Storage, for the Electric Storage Program authorized in the Decision dated July 28, 2021. [↑](#footnote-ref-14)
14. The wholesale market function value is to some extent reliant on ISO-NE, NEPOOL, and ultimate tariff rules adopted under Order 2222, but even if not allowed due to the ISO-NE tariff limiting sharing of wholesale market resources for retail and customer value, the Authority would still encourage use case stacking of NWA DERs including batteries, EV, and other demand-side resources. [↑](#footnote-ref-15)
15. Major storms are defined in Docket No. 86-12-03, dated March 22, 1995, p. 2. The “major storm exclusion criterion [that] is based on a statistical analysis of the most recent four calendar years of reliability data. A cumulative frequency distribution of the number of locations requiring service restoration work per day would be calculated for this four year period. Whenever the frequency of restoration work locations exceeds the 98.5 percentile, by company and/or region, the major storm criterion would be met.” [↑](#footnote-ref-16)
16. The Authority understands this criteria to be similar to that currently employed in New York state. [↑](#footnote-ref-17)
17. Comments of Northeast Clean Energy Council and Renew Northeast, Re: Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, Nov. 13, 2020, \*NECEC and RENEW Nov. 13, 2020 Comments“), p. 2. [↑](#footnote-ref-18)
18. *Id.* [↑](#footnote-ref-19)
19. While the discussion herein is related to the use case stacking discussion in Section G above, Section M specifically addresses how PURA will consider qualification or disqualification of NWAs in other programs and/or markets. Section G discusses how such program and/or market participation will affect, and be factored into as appropriate, NWA valuation and project selection. [↑](#footnote-ref-20)
20. See, Green Mountain Power (undated). Bring Your Own Device program. Retrieved from: <https://greenmountainpower.com/rebates-programs/home-energy-storage/bring-your-own-device/> [↑](#footnote-ref-21)
21. NECEC and RENEW NE Comments at pages 18 to 19 citing Advanced Energy Economy. Utility Earnings in a Service-Oriented World: Optimizing Incentives for Capital- and Service-Based Solutions (Jan. 2018). [↑](#footnote-ref-22)
22. Chew, B., Myers, E., Adolf, T., Thomas, E. (2018, November). Non-Wires Alternatives: Case Studies from Leading U.S. Projects. E4theFuture, PLMA, SEPA. Retrieved from: <https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/>, pp. 53-55. [↑](#footnote-ref-23)
23. Buckley, B., Titus, E., and Walker, C. (2017) State Leadership Driving Non-Wires Alternative Projects and Policies. NEEP. Retrieved from: <https://neep.org/sites/default/files/resources/NWA%20brief%20final%20draft%20-%20CT%20FORMAT.pdf> [↑](#footnote-ref-24)
24. Arizona Public Service (2018, January 19). Punkin Center Battery Storage Video. Retrieved from: <https://www.youtube.com/watch?v=cjSRvaP7Ucg> [↑](#footnote-ref-25)
25. Chew, B., Myers, E., Adolf, T., Thomas, E. (2018, November). Non-Wires Alternatives: Case Studies from Leading U.S. Projects. E4theFuture, PLMA, SEPA. Retrieved from: <https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/> [↑](#footnote-ref-26)
26. Chew et al, 2018, p. 67 [↑](#footnote-ref-27)
27. Buckley, B., Titus, E., and Walker, C. (2017) State Leadership Driving Non-Wires Alternative Projects and Policies. NEEP. Retrieved from: <https://neep.org/sites/default/files/resources/NWA%20brief%20final%20draft%20-%20CT%20FORMAT.pdf> [↑](#footnote-ref-28)
28. Chew et al, 2018, p. 65. [↑](#footnote-ref-29)
29. Chew et al, 2018, pp. 56-57. [↑](#footnote-ref-30)
30. Chew et al, 2018, pp. 50-51. [↑](#footnote-ref-31)
31. For more information, see, Vermont System Planning Committee at <https://www.vermontspc.com/>. [↑](#footnote-ref-32)