SECTION 3: GRID MODERNIZATION

The electric sector and its infrastructure are the veins and arteries that power modern society. Nationally, the electric sector accounts for approximately 5% of the gross domestic product (GDP). Indirectly, the electric sector contributes much more, enabling businesses and industry to create the goods and services that make up the remaining 95% of the GDP and improving productivity, health, safety, comfort, and convenience. However, today's electric grid faces new and growing challenges such as rising energy demand, growing deployment of distributed energy generation resources (DERs) like rooftop solar, ambitious climate and energy policies, and increasing storm frequency and intensity. These, and other challenges, are impacting the affordability, resilience, and reliability of our electric distribution system.

In response to these challenges, PURA determined that it needed a distinct strategy for grid modernization, separate from traditional electric sector regulation. In October 2019, PURA issued an Interim Decision in Docket No. 17-12-03, PURA Investigation into Distribution Planning of the Electric Distribution Companies (EMG Interim Decision) outlining the Authority's framework for investigating both near- and long-term strategies to implement an Equitable Modern Grid (EMG) for Connecticut. This framework is designed to foster innovative solutions that address the major challenges and opportunities facing the electric sector and has four objectives:

- Support (or remove barriers to) the growth of Connecticut's green economy;
- Enable a cost-effective, economy-wide transition to a decarbonized future;
- Enhance customer access to a more resilient, reliable, and secure commodity; and
- Advance the ongoing energy affordability dialogue in the state, particularly in underserved communities.

What is a "reopener docket"?
A docket that is initiated to either reassess or continue evaluating a specific part of the original docket's decision. It helps to maintain continuity between related dockets. "Reopened" proceedings use the naming convention "##-##-##re0#" in PURA's docket database.

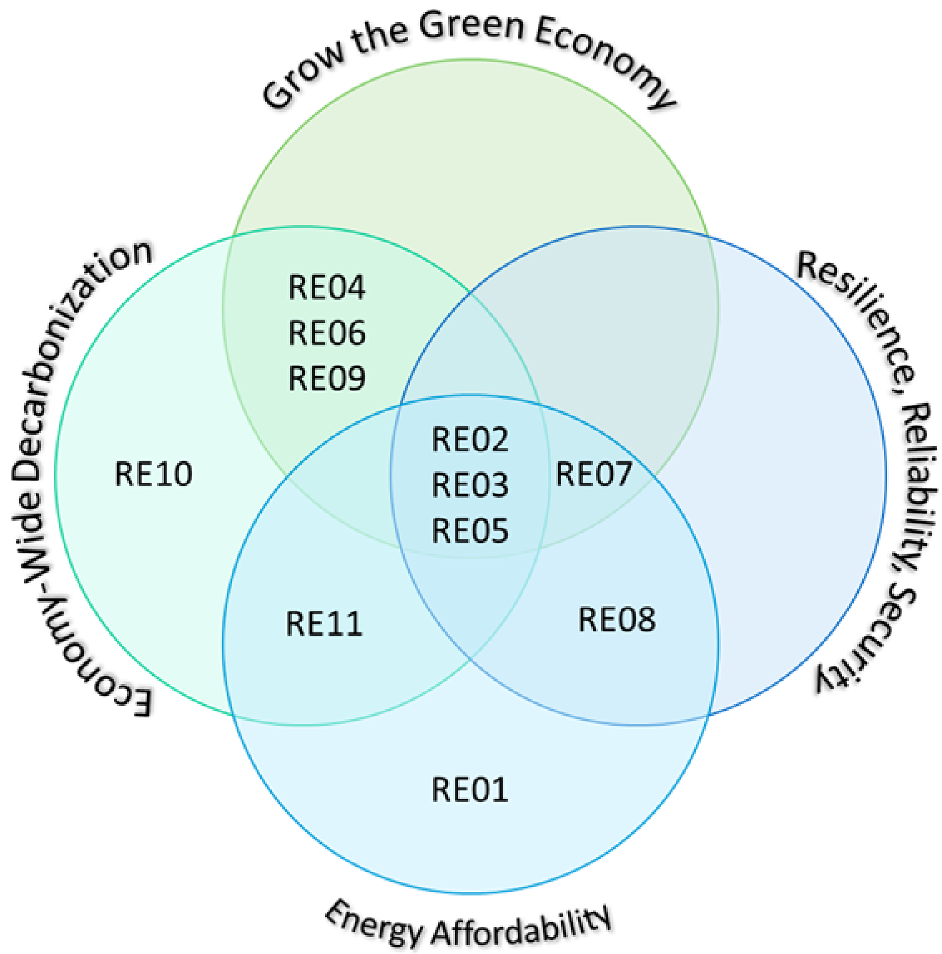
All four objectives are inextricably connected and, thus, no single objective can be accomplished without the others if an Equitable Modern Grid is to be achieved. Similarly, the whole of an Equitable Modern Grid is greater than the sum of its parts, as the realization of each objective can further the achievement of the others.

The 2019 EMG Interim Decision introduced 11 sub-topics for further investigation through a series of "reopened" proceedings, where PURA has been and, in one case, continues to evaluate potential solutions for their cost-effectiveness and ability to meet the objectives of the framework in the long-term. Since 2019, PURA has initiated decisions or final reports in all 11 reopeners, with several having moved into the annual program review stage. The reopeners and their progress are as follows:

Figure 8: Progress Across EMG Reopener Dockets

Though each reopener contributes towards all four EMG objectives, some further more of the objectives than others. Figure 9 below helps to demonstrate the relationship between each topic and the EMG objectives, and PURA's strategy to ensuring all four are accomplished through this comprehensive approach.

Figure 9: Reopener Alignment with EMG Objectives



KEY GRID MODERNIZATION TOPICS IN 2023

As demonstrated by Figure 9 above, each EMG reopener docket addresses one or more of the original EMG Interim Decision objectives. As of January 3, 2024, the Authority has now issued final decisions or reports in all 11 of the EMG reopener dockets and has moved on to full implementation of the programs and policies designed by these final documents.

In 2023, in addition to its numerous program annual review dockets, the Authority issued multiple groundbreaking grid modernization decisions, each supporting the EMG Framework as a whole, and making significant contributions towards the Framework's objectives. In Docket No. 23-05-01, Annual Review of Affordability Programs and Offering

(Energy Affordability Annual Review), PURA's October 11, 2023, Final Decision assessed the ongoing residential energy affordability programs offered by the state's regulated electric and gas utilities, as well as the 2024 implementation of the residential Low-Income Discount Rate (LIDR) and changes to the Matching Payment Plan (MPP) program as directed by Section 30 of Public Act 23-102, An Act Strengthening Protections for Connecticut's Consumers of Energy. In Docket No. 22-08-07, Innovative Energy Solutions Program Cycle 01, the Authority's December 13, 2023, Decision, formally approved seven innovative projects for pilot funding beginning in 2024. Additionally, PURA released a Final Legislative Report on December 13, 2023, in Docket No. 23-08-09, Annual Electric Distribution Company Reliability and Resilience Framework Review, reporting on the reliability of each EDC. In Docket No. 22-06-29, PURA Investigation into Distribution Energy Resource Interconnection Cost Allocation, PURA's December 20, 2023, Decision revises the policy regarding how to allocate distribution system upgrade costs that result from the interconnection of residential DER projects. The Authority also issued a decision in Docket No. 22-06-05, PURA Implementation of Public Act 22-55, on December 20, 2023, reviewing EDC proposals for front of the meter (FTM) storage resources under the framework it had previously designed in 2022.

In addition, as a result of significant Authority analysis and stakeholder input throughout 2023, PURA also issued important grid modernization final decisions in early 2024. In Docket No. 17-12-03RE02, PURA Investigation Into Distribution System Planning Of The Electric Distribution Companies – Advanced Metering Infrastructure, PURA's January 3, 2024, Decision establishes a framework that serves as a regulatory roadmap for the EDCs to invest in advanced metering infrastructure (AMI), while protecting ratepayers and advancing the state's policy goals. In Docket No. 17-12-03RE10, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Building Blocks of Resource Adequacy and Clean Electric Supply, PURA issued a Final Legislative Report on February 1, 2024. This report outlines the Authority's investigation into the procurement of Standard Service (SS) for EDC customers in accordance with Section 16 of Public Act 23-102, An Act Strengthening Protections for Connecticut's Consumers of Energy. Further details on each of these decisions are discussed below.

Progress Advancing Energy Affordability

Each year, PURA conducts a comprehensive review of the energy affordability and arrearage forgiveness programs (AFP) offered by the EDCs and LDCs through one consolidated proceeding. The Annual Review process provides the Authority with an opportunity to assess these programs' effectiveness at addressing ongoing energy affordability issues, particularly for low-income or disadvantaged communities, as well as their impact on reducing overall unpaid utility bills. The programs available to help customers pay their bills are the result of collaboration between the Authority, the utilities, the Office of Consumer Counsel, EOE, the Department of Social Services (DSS), the General Assembly, low-income and community advocates, and other stakeholders with a commitment to ensuring these offerings are as helpful to customers as possible. These programs include the following summarized by Table 8:

Table 8: Connecticut Energy Affordability and Arrearage Forgiveness Programs

Program or Policy	Definition	Eligibility	Enrollment Process
Hardship Verification	A designation that protects residential customers from service shutoff during the winter and makes them eligible for certain energy affordability programs. Medical protection status is also available to customers with serious or life-threatening medical conditions.	Customers who receive public assistance benefits from DSS, have a household income of <60% of State Median Income (SMI), or have a serious or life-threatening medical condition.	Contact your electric utility, or your local Community Action Agency (CAA).
Connecticut Energy Assistance Program	Applies direct funding (typically in the range of $250-$600) towards your heating bill.	Customers who also receive public assistance benefits from DSS, or have a household income of <60% of State Median Income (SMI).	Apply directly at your local CAA.
Matching Payment Plan	A payment plan for hardship customers heating with electricity or gas with past-due balances. Each payment made by the customer is matched by the utility until the balance is eliminated.	Customers who qualify as medical or financial hardship through DSS or a Community Action Agency (CAA) who have past-due balances.	Contact your local natural gas or electric utility company, or CAA directly.
Flexible Payment Plan	A payment plan for any active electric, residential customer with a past-due balance. Customers make monthly payments to prevent service shutoff.	Any active electric, residential customer of Eversource or United Illuminating.	Contact your electric utility company directly.

These programs are designed to ensure that as many customers and their varying circumstances can be addressed as possible. The Authority conducted its review of the 2022-2023 Program Year for these programs through Docket No. 23-05-01, Annual Review of Affordability Programs and Offerings (Energy Affordability Annual Review). Key findings, issues, and program modifications included in the October 11, 2023, Decision in this docket are discussed below.

Matching Payment Plan (MPP) Program

Connecticut law provides that residential electric or gas heating customers with unpaid utility bills who meet either income or medical qualifications are eligible to enter into an amortization agreement with their utility to reduce their unpaid balance. The Matching Payment Plan (MPP) program offered by Eversource and UI is the programmatic implementation of this law. Through the MPP, hardship customers (i.e., customers who receive public assistance benefits from DSS, have a household income of <60% State Median Income, or have a serious or life-threatening medical condition) are put on a payment plan to eliminate past-due utility balances. Each payment made by the customer is matched by the utility until the balance is eliminated.

Payment Calculation

Historically, a customer's monthly payment was calculated using the total of the last 12 months of a customer's bills, less any award from the Connecticut Energy Assistance Program (CEAP), divided by 12. However, this calculation methodology required modification due to the launch of LIDR on January 1, 2024. Accordingly, the Authority modified the monthly payment calculations for the MPP program to use the average of the past 12 months of kWh usage, multiplied by the average of the past 12 months of retail rates.

Annual Participation Metrics

In the 2022-2023 MPP Program year, 68,695 customers participated in MPP. The Authority found that all companies saw an increase in MPP enrollment, up from 60,052 in the 2021-2022 MPP Program Year. This was likely driven primarily by the implementation of auto-enrollment for customers who participated the previous year. The Authority will continue to monitor the auto-enrollment process and its impact on MPP participation to identify any trends.

The Authority had previously established a goal of 65% of participants successfully completing payments between November 1 and May 1 of a given program year (Phase 1). Upon completing Phase 1, they receive their matching payment. During this program year, 59% of participants across Eversource, Yankee Gas, CNG, SCG, and UI successfully completed Phase 1. The companies all reported a variety of reasons that customers did not complete the program.

In evaluating the MPP and the utilities' explanations for a 59% completion rate, the Authority reached the conclusion that it may be necessary to re-examine what is considered success in the program, particularly where companies are seeing the same customer participate in MPP year after year. Therefore, the Authority directed the utilities to propose a revised definition of success for the MPP that includes, at a minimum, tracking the length of a customer's participation in the program to reach a zero past due balance. In advance of this proposal, the Authority also approved an expanded set of metrics used to track and assess participation rates going forward.

Figure 10: Participation Phases of MPP

MPP Phase I

Phase I of the MPP is the period between November 1 and May 1 of the MPP year. To receive a matching payment, customers must comply with the MPP requirements as of the time they enroll in the MPP and enter into a payment arrangement.

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MPP Phase II

Phase II is the period between May 2 and October 31 of the MPP year. The customers who successfully complete Phase I are eligible to participate in Phase II. Customers participating in Phase II must make payments as scheduled or they are subject to the normal disconnect process. Phase II of the program is much like Phase I. Customers receive matching payments equal to the amount they paid and/or on behalf of the customer through CEAP. Lastly, customers have an opportunity to make up missed payments by October 31 to successfully complete MPP.

Enrollment

Customers who participated in the MPP during the previous year who still have a past-due balance are automatically re-enrolled. Automatically enrolled customers receive a letter confirming their re-enrollment, identifying their monthly payment amount, and reminding them to apply for CEAP energy assistance. For customers that are newly enrolling, they need to demonstrate income eligibility and to apply for CEAP between November 1 and May 1.

In the 2023 Annual Review, PURA examined Eversource and UI's proposals implementing a rolling 12-month hardship verification designation, which serves as income eligibility. This will help minimize the number of steps that customers need to take to access the programs and help increase participation. After reviewing both companies' proposals and associated costs, the Authority directed both companies to implement rolling hardship verification by January 1, 2024, coincident with the launch of LIDR. The Authority did then allow an extension to Eversource until May 1, 2024.

Modifications to MPP Program by Public Act 23-102

Importantly, the enrollment requirements that have historically been used in the MPP program were modified, along with multiple other changes to the MPP, by

Section 30 of Public Act 23-102. The most significant amendments to MPP were to the eligibility criteria, the calculation of a customer's matching payment, and the timing of the distribution of matching payments. Specifically, the revised MPP is no longer tied to the heating source on which a residential customer relies. Additionally, residential customers are no longer required to apply and be eligible for benefits available under CEAP or a state-appropriated fuel assistance program. Rather, residential customers are now only required to meet the income eligibility requirements of CEAP or a state-appropriated fuel assistance program. Residential customers also must be eligible for financial hardship programs with the gas or electric distribution company. Residential customers are still required to authorize the gas or electric distribution company to send a copy of the customer's monthly bill directly to any energy assistance agency for payment and to enter into and comply with an amortization agreement that is consistent with decisions and policies of the Authority.

Throughout the proceeding, the Authority sought information from the utilities regarding implementation of the authorized changes to MPP, including costs and an associated timeline, to ensure its timely implementation. Both companies testified that the changes would take multiple months to implement. As such, the Authority directed the utilities to make the IT changes necessary to implement the New MPP no later than November 1, 2024, which is the start of next year's MPP program year, and to provide an update regarding such changes and the utilities ' implementation of the New MPP in the 2024–2025 AFP Plan in next year's annual affordability proceeding, Docket No. 24-05-01. The Authority also provided multiple points of clarification regarding the statute to ensure accurate implementation by November 1, 2024.

Therefore, the Authority permitted the utilities to continue using the eligibility requirements, the calculation of a customer's matching payment, and the timing of the distribution of matching payments (i.e., at the end of each phase) that were in place prior to the passage of Public Act 23-102, as described above for the 2023-2024 MPP Program Year. However, all changes directed by Public Act 23-102 must be in place by November 1, 2024. All other modifications made by the 2023 Annual Review to the MPP Program not affected by Public Act 23-102 will be implemented this winter (i.e., the 2023-2024 Program Year).

Low-Income Discount Rate (LIDR)

In 2022, PURA directed the EDCs to implement a LIDR with an overall eligibility cap at 60% State Median Income (i.e., Tier 1) and eligibility for Tier 2 aligned with existing state benefit programs (i.e., up to 160% FPG) through its October 19, 2022 Final Decision in Docket No. 17-12-03RE11, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – New Rate Designs and Rate Reviews, (LIDR Decision). In Docket No. 23-05-01, PURA reviewed key LIDR issues including the utilities' eligibility verification and enrollment plan and how the LIDR will interact with MPP going forward, particularly with the implementation of Public Act 23-102.

Eligibility Verification and Enrollment

The LIDR Decision established multiple avenues for customers to verify eligibility and enroll on the LIDR. First, the EDCs must automatically enroll all customers designated as financial hardship and all electric customers receiving CEAP awards into Tier 1 of the LIDR. Second, each EDCs' customer service representatives (CSRs) must accept proof of verification documentation for Tier 1 or Tier 2 eligibility from customers who opt in to receive a LIDR. Finally, the Authority approved new MOUs between the EDCs and CAAs and Operation Fuel, Inc. (Operation Fuel) to encourage the enrollment of customers onto Tier 2 of the LIDR. The Authority further approved the EDC-developed list of eligible low-income or public assistance benefits to be used by CAAs and Operation Fuel to qualify eligible customers for Tier 1 or Tier 2.

The October 11, 2023, Decision in Docket No. 23-05-01 discussed ways to ensure that all eligible customers will be efficiently and correctly enrolled in the LIDR Tier for which they are eligible. One strategy that will help ensure this is through data-sharing agreements between DSS and the EDCs, which the utilities were on track to implement by January 1, 2024.

Additional Affordability Modifications

In addition to specific programmatic changes or direction regarding MPP or LIDR, the Authority also approved or directed changes in Docket No. 23-05-01 that will help improve energy affordability in Connecticut including changes to the companies' security deposit practices, late payment charge policies, and a plan to evaluate affordability for non-residential customers.

Security Deposits

The collection of security deposits is commonly cited as a strategy for prudently managing the cost of bad debt for residential customers (i.e., customer non-payment) by utilities. In Connecticut, the EDCs charge security deposits from non-hardship customers as a condition for connection. However, in a scenario where a customer is required to pay a deposit for service restoration after being shut off, given the number of available programs that should prevent service termination, the customer should instead be enrolled in those programs for which they are eligible. For new residential customers, where there may not be enough evidence to determine if the customer qualifies for a hardship designation (and therefore exempt them from paying a security deposit), the argument that a security deposit is the best practice for managing the cost of bad debt is still flawed since the benefit of imposing a security deposit is conditioned on the customer's ability to pay.

Accordingly, the Authority directed the utilities to remove the payment of a security deposit requirement for residential customers as of the date of the Decision, and to return any security deposits previously charged, plus any accrued interest to residential non-hardship customers. Additionally, PURA prohibited the utilities from refusing service to a customer based on the customer's financial inability to pay a security deposit. As noted by Eversource, security deposits are among the highest dissatisfiers and escalated complaint types for residential customers. Thus, with a permanent suspension of residential security deposits, customer interactions are likely to improve and more effort can be placed on enrolling customers in an appropriate energy affordability program.

Late Payment Charges

The Authority evaluated the utilities' collection of late payment charges (LPC) from 2018 through 2022. Specifically, the Authority examined: (1) the utilities' average, maximum, and minimum LPCs incurred by customers by customer class (i.e., residential, and non-residential classes) for each year from 2018 through 2022; and (2) the impact LPCs have on the utilities' uncollectibles. The submitted data further distinguished the residential class by hardship and non-hardship customers.

The utilities' LPC data shows that the EDCs assessed higher LPCs compared to the gas companies. In addition, the maximum LPC amount charged by UI is the highest of all the utilities. The Authority review of the LPC data raises multiple concerns, including whether UI properly screened these customers for hardship eligibility and how many customers had service terminated because of their inability to pay their bills. The Authority will continue to monitor LPCs for each company in an effort to address these concerns. As such, the Authority ordered each of the utilities to submit the average, maximum, and minimum LPCs incurred by customers, by customer class, in the previous year; and the impact LPCs have on uncollectibles, no later than January 15, 2024, and annually thereafter in the relevant annual energy affordability docket.

Non-Residential Programs and General Affordability

In light of the recent significant increase in energy supply rates as of January 2023, PURA determined that these annual proceedings are an appropriate opportunity to also start explicitly examining the utilities' energy affordability offerings for non-residential programs, in addition to residential initiatives. The Authority requested data regarding non-residential terminations from each company and solicited comments on the respective available energy affordability programs. Collectively, the EDCs and LDCs reported over 7,000 non-residential terminations in 2022, which was nearly double that of 2021. This is likely primarily due to the end of the COVID-19 shut-off moratorium for non-residential customers in July 2021.

Both the Eversource and Avangrid companies offer Flexible Payment Arrangements to assist commercial and industrial customers with delinquent balances. Regardless, the Authority recognizes the need to investigate further the topic of non-residential affordability going forward. As such, Authority directed each of the utilities to provide the total amount of uncollectibles and the amount of uncollectibles attributable to residential (distinguished between hardship and non-hardship) and non-residential customers in the next annual affordability review, Docket No. 24-05-01. In addition, the

Authority directed the utilities to include the number of service terminations, the number of active flexible payment arrangements, and the average, minimum and maximum payments for non-residential customers. The Authority will use this data to examine the portion of uncollectibles attributable to non-residential customers and whether the current programs can improve to enhance energy affordability for non-residential customers.

Additional 2023 Affordability Review Resources

- Final Decision
- Eversource MPP Webpage
- UI MPP Webpage

Standard Service Procurement

Separate from the programs designed to reduce and eliminate overdue bill balances, and programs designed to lower bills overall for low-income customers, the Authority has also been investigating mechanisms to improve affordability for ratepayers overall. As previously discussed, customers' electric bills are comprised of costs grouped into three primary categories: generation or supply costs; distribution costs; and transmission costs. Transmission costs are the costs required to transmit energy on an interstate basis throughout the regional grid (ISO New England) and are federally regulated. The Authority regulates distribution costs, or the cost of delivering energy throughout Connecticut and directly to end-users, through rate cases, RAM proceedings, PBR, or other tools. The cost of the actual generation of energy is set competitively through the regional wholesale electricity market. In Connecticut's de-regulated electricity market, Eversource and UI do not own electricity generation resources that supply electricity to customers, but instead purchase electricity from the wholesale electricity market and pass that cost directly through to customers. These offerings are known as Standard Service (SS) for residential and small load customers and Last Resort Service (LRS) for commercial or large-load customers. Customers can choose to source their electricity supply from a third-party retail supplier[1] or from their EDC's SS or LRS default option.

Historically, electricity supply prices have been driven by factors such as the weather and its impact on demand for energy and the infrastructure available to meet energy demand (i.e., the capacity and fuel mix of available generation resources and the pipelines, transmission, or other infrastructure to transport fuel). In recent years electricity supply prices have been volatile due to macroeconomic factors such as the COVID-19 pandemic and the Russian invasion of Ukraine. Moreover, natural gas comprises approximately 45% of the New England regional fuel mix, ensuring that the price of natural gas plays an outsized role in driving the price of electricity in the wholesale markets. In 2022, the price of natural gas rose sharply, bringing the price of electricity in the ISO New England wholesale markets along with it. As a result, for the first half of 2023, the price of SS doubled for Eversource and UI residential customers compared to the prior six-month period. This significant increase in supply charges adversely impacted EDC customers with higher-than-expected electricity costs for household budgets and business operations alike.

As a result, Section 16 of Public Act 23-102 directed PURA to evaluate the SS procurement process and submit a report regarding its findings to the General Assembly. On February 1, 2024, PURA issued a Final Report in Docket No. 17-12-03RE10, PURA Investigation into Distribution System Planning of the Electric Distribution Companies - Building Blocks of Resource Adequacy and Clean Electric Supply, and submitted a report to the Energy and Technology Committee of the Connecticut General Assembly. In this report, PURA reviewed Connecticut's existing SS Procurement Process and Objective Pathways Summary process and compared it with those of peer jurisdictions. Additionally, the Authority identified and considered potential modifications to the SS procurement process for consideration by the General Assembly.

By statute, Connecticut's SS Procurement Objectives are to achieve: (1) relatively low prices; (2) stable prices; and (3) market-based prices over time.[2] Each must be balanced with the others to achieve an outcome that optimizes all three. The Procurement Objectives are not mutually exclusive; however, different potential procurement process modifications may prioritize or advance one objective more-so than the others, or even at the expense of the others. As such, through this report, the Authority provided 10 potential SS procurement process modifications in the context of their potential impact on the three Procurement Objectives. Additionally, the Authority grouped together the potential procurement process modifications that serve the same SS Procurement Objectives to demonstrate potential pathways to achieving those objectives. potential SS procurement process modifications in the context of their potential impact on the three Procurement Objectives. Additionally, the Authority grouped together the potential procurement process modifications that serve the same SS Procurement Objectives to demonstrate potential pathways to achieving those objectives.

Importantly, the Authority is not advocating for specific modifications to the procurement process in this report. Instead, by taking the approach outlined above, the Authority is providing the Energy and Technology Committee, and the General Assembly more broadly, with a set of potential options, both individual steps and collective pathways, to achieve and balance the SS Procurement Objectives. The Authority also outlines some potential next steps including first, conducting additional outreach to wholesale suppliers to solicit confidential input on the ten potential modifications discussed in this report. Second, where necessary, further investigation of the potential impacts of high-interest SS procurement process modifications. Third and finally, adopting any legislative changes necessary to implement the Energy and Technology Committee's priority modifications to the SS procurement process. The Authority stands ready to continue supporting the Energy and Technology Committee's interest in this topic as may be helpful.

Additional Standard Service Procurement Resources

- Final Report to Legislature

Progress Enabling Decarbonization

Residential DER Interconnection Cost Allocation

A key enabling component of the electric distribution system to ensure deployment of solar PV systems, battery electric storage systems, and other kinds of distributed energy resources (DERs) are ability to support two-way flows of energy. DERs are an important tool to meeting the state's climate goals, and can be an even more important tool in providing customers with resiliency solutions and providing demand flexibility, which provides benefits to both the customer and the grid at large. To unlock the benefits of DERs, however, they must be interconnected to the grid. While this sounds simple, without carefully designed standards in place, a new interconnecting resource could compromise the reliability or safety of the distribution system; conversely, inefficient interconnection standards and protocols can inhibit the timely deployment of DERs.

The EDCs have had common DER interconnection guidelines in place since 2004 to ensure and maintain grid reliability after interconnection.[3] To assess whether a new DER would compromise the grid, the EDCs use a set of four technical screens. These screens prevent the addition of a new DER when its generation capacity would exceed the hosting capacity[4] limits of the infrastructure at that point on the distribution grid. In a situation where the DER does exceed the current hosting capacity, the EDCs offer the DER applicants two options:

1. Reduce the proposed generation capacity to pass the technical screens;[5] or
2. Pay for distribution system upgrades.

Based on the longstanding policy that allocates all interconnection costs to a new customer interconnecting to the distribution system for standard electric service, the interconnection guidelines required that DER applicant that exceeds the hosting capacity limits to pay for all system upgrade costs required to interconnect to the distribution system. In other words, the customer that in the moment causes the need for upgrades, pays for them, even if projects that come afterwards benefit (i.e., freeride).

However, under this cost-causation principle, residential DER applicants can face the potential for thousands of dollars in distribution upgrade costs. As a result, these customers will often either downsize their proposed system or withdraw their application altogether. Currently, the number of customers that find themselves in this situation is relatively low; 1.24% of all residential DER applicants, as of 2021. However, this number has nearly tripled since 2019, concurrent with increasing year over year applications tied to the success of the Residential Renewable Energy Solutions (RRES) Program.[6] It is clear that the percentage of residential DER projects triggering distribution upgrades is likely to continue to increase into the future. Manifest in that conclusion is the potential for distribution upgrades to become an increased barrier to DER deployment, as cost savings for DER customers and profit for DER developers are a large driver of overall DER deployment.

Recognizing this growing issue, the Authority committed to investigating methods to improve the interconnection standards and upgrade cost allocation frameworks used by the EDCs to remove barriers to DER deployment. Taking into consideration stakeholder input and guidance from the PURA-established Distributed Generation Policy and Technical Working Groups (IX Working Group),[7] the Authority issued revised cost allocation policies regarding system upgrade costs triggered by the interconnection of residential DER projects through its December 20, 2023 Decision in Docket No. 22-06-29, PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation.

The most significant change in this decision is that residential DER applicants that fail the technical screens and would be required to pay for a new or substantially upgraded distribution transformer to enable their project are no longer responsible for paying the cost of the transformer upgrade upfront. Instead, two approaches will be used to cover the cost of distribution transformer upgrades depending on whether the applicant meets the Environmental Justice (EJ) eligibility requirements:

1. For applicants meeting the EJ eligibility requirements (EJ applicants), the cost of upgrading the distribution transformer will be recovered by the EDCs across all ratepayers through their next rate case proceeding.
2. For applicants not meeting the EJ requirement (non-EJ applicants), the EDCs will offset a portion, and ideally all, of the costs of non-EJ distribution transformer upgrades through an adder charged to all non-EJ applicants as part of the interconnection application fee. Any remaining transformer upgrade costs will be recovered by the EDCs across all ratepayers through their next rate case proceeding.

Consistent with the other energy programs under PURA's jurisdiction, EJ eligibility means the applicant's income is no more than 60% of the state median income, or the applicant is deploying the project in a distressed municipality as defined by the Connecticut Department of Economic and Community Development. The Authority directed the EDCs to use the existing income verification process already in place for the RRES program, and to the extent possible, use automatic verification of projects in a distressed municipality.

The Authority chose to exempt EJ applicants from paying an interconnection application fee adder for multiple reasons, the primary being that requiring an additional fee for EJ applicants is counter to the policy objective of supporting residential DER for EJ communities whose deployment levels already lag the stated policy goals. Further, it would be inequitable to require EJ applicants to pay for the projects of non-EJ applicants. Additionally, providing an applicant's EJ status upon application does not introduce a significant barrier nor any delays to processing applications, and the impact to non-participating ratepayers for the remaining costs of transformer replacements will be minimal, especially in the near term.

For non-EJ applicants, the Authority recognized the need to implement an adder that fairly distributes the costs relative to the benefits of the upgrade. Therefore, the Decision establishes a cap on the adder to avoid burdening DER applicants with unreasonable fees, consistent with stakeholders' feedback. While determining a precise cap is currently infeasible as there is no concrete data indicating the price point at which an application fee adder would begin to negatively impact DER deployment, based on limited historical data, the Authority found that an adder fee between $3-$150 could cover all or most anticipated transformer costs. Based on cost analysis in the Decision, the Authority found that an application fee cap of $50 is sufficient.

Importantly, this new policy applies only to the costs resulting from a new or upgraded transformer. If a residential DER interconnection requires a new transformer and additional distribution system upgrades, the customer will be responsible for the costs of the total upgrade minus the cost of replacing the transformer. This distinction is necessary because costs of non-transformer upgrades vary significantly and can be much larger than transformer costs. The Authority does not currently intend to provide incentives to deploy residential DERs in locations that require significant and costly upgrades. The Authority notes that where this situation occurs, there may be non-wires solutions that could be considered through the Non-wires Solutions Process anticipated to launch in 2025.

Additional Residential DER Interconnection Resources

- Final Decision

Non-Residential DER Interconnection Cost Allocation Straw Proposal

The issue of interconnection cost allocation is not limited to residential DERs and in fact results in even more significant costs and time delays for non-residential DER projects. Under the current application of the cost-causation principle, the EDC assigns the full cost of the upgrade to the interconnecting customer as that DER project triggered the needed upgrade. The cost-causation principle results in one non-residential DER project incurring significant costs for upgrades that other DERs contributed to the need for and other DERs that will benefit from it. For example, a non-residential DER connecting to the distribution system may require the installation of additional infrastructure to accommodate a generators' power flow and maintain the safety and reliability of the grid. These upgrades range in cost, though the average upgrade cost for projects greater than 2 megawatts (MW) reached $4,733,520 in 2018.

If a developer agrees to pay for the upgrade under the cost-causation principle, the result is an inequitable distribution of infrastructure costs among grid stakeholders. For example, if a single DER developer finances a distribution system upgrade, additional hosting capacity is generally created on the circuit. Therefore, any future projects may be able to interconnect due to the additional hosting capacity created without having to share the cost of the upgrade. This creates an incentive for DER developers to game the

the interconnection queue to avoid being the DER that will incur the cost. Moreover, DERs that interconnect on a circuit with limited hosting capacity that do not trigger a distribution system upgrade do, however, significantly contribute to the need for a future upgrade; yet these projects do not financially contribute towards future upgrade costs.

To address this issue, the Authority issued a Straw Proposal on December 22, 2023, in Docket No. 22-06-29RE01, PURA Investigation into Distributed Energy Resource Interconnection Cost Allocation – Non-Residential Interconnection Upgrades. In this proposal, PURA recommends shifting from a cost-causation principle to a "beneficiary pays" principle. Under this principle, distribution system upgrade costs are assigned to interconnecting customers in proportion to that customer's benefits from and contribution to the need for the upgrade. Specifically, interconnecting customers are charged on a per-kW basis. This approach is more transparent and equitable because it recognizes that some interconnecting customers both contribute more to and benefit more from distribution system upgrades than others and assigns costs proportional to that attribution.

In order to implement the "beneficiary pays" principle, there must be a method of evaluating how multiple projects interconnecting at a certain point will impact the grid and how they will benefit from resulting upgrades. Thus, the Authority proposed the use of a Group Study Process. Group Studies will allow the EDCs to process applications simultaneously rather than sequentially, leading to a more efficient use of the EDC's resources, lower interconnection costs, and faster interconnection timelines. The Authority proposes allowing the EDCs to form Group Studies any time they receive more than one interconnection application on a portion of the distribution system where the operation of multiple DERs may have cumulative impacts and may require modifications to the distribution system. Through this process the EDCs can identify the beneficiaries and contributors to any upgrade cost drivers. Once the EDCs have that information, they can allocate costs proportionately to the interconnecting projects responsible for the costs.

The Straw Proposal also outlines several related issues that will need to be resolved. For example, while the Group Study Process is a needed incremental improvement, it is still a reactive planning approach. The Group Study Process only occurs when the need for a distribution system upgrade already exists and DER deployment is already delayed compared with the upgrade being developed and deployed either when it is identified in the application review process or through proactive planning. Stated more simply, any amount of time taken through the Group Study Process extends a pre-existing delay. A proactive approach to allocating costs could provide price signals correlated with ideal points of interconnection, and address system upgrades as soon as possible. Further, the Authority flagged the need to integrate the Non-wires Solutions Process (NWS Process) and Integrated Distribution System Planning (IDSP) as the means to most strategically and holistically coordinate the deployment of DERS and necessary grid upgrades.

The Authority requested written comments on the Straw Proposal from stakeholders by February 14, 2024. These comments will be used to help determine future stakeholder input opportunities and to make refinements to the proposed approach.

IX Working Group

As a result of the November 25, 2020, Decision in Docket No. 17-12-03RE06, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Interconnection Standards and Practices, the Authority established the IX Working Group to consider changes to the current interconnection policies of the EDCs, among other issues. The IX WG has been consistently meeting since March 2021, with the mission of: "accelerat[ing] safe, reliable and economical interconnections of distributed energy resources in Connecticut, through a transparent and informal public forum where technical and policy stakeholders openly share their experience, knowledge and challenges, on common ground, where solutions and recommendations to policy makers strive for consensus, so that renewable energy in Connecticut can flourish, while leading the nation through an example of mutual respect and collaboration."

On October 20, 2023, the Authority retained a formal IX Working Group Facilitator to provide both administrative support and assist with the facilitation of discussion and development of strategies to improve transparency of the interconnection process, including but not limited to:

- Public distribution system interconnection queues;
- Identify best uses of hosting capacity maps;
- Establish and make public reporting requirements; and
- Review of the Non-Residential Renewable Energy Solutions (NRES) and the Shared Clean Energy Facility (SCEF) program solicitation documents for consistency with the interconnection process and to identify possible areas of improvement.

The IX Working Group will continue to meet on a monthly basis and provide important stakeholder information and input to the Authority to continue improving interconnection policies in Connecticut.

Additional Non- Residential DER Interconnection Resources

- Straw Proposal
- IX Working Group Webpage

Progress Supporting Resilience & Reliability

Electric Reliability Reporting

By law, the EDCs are required to submit annual reliability data to PURA for the previous 12 months in terms of various power outage metrics that excludes outages caused by major storms, scheduled outages, or outages caused by customer equipment.[8] Specifically, the EDCs are required to report System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). In turn, the Authority is required to report this data to the Energy & Technology Committee of the General Assembly.

In 2022, PURA issued a decision in Docket No. 17-12-03RE08, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs (RE08 Decision), which expanded the reliability data the EDCs are required to track and report in order to provide more granular, customer-focused reliability performance data including customer average interruption duration index (CAIDI), customers experiencing multiple interruptions (CEMI), and customers experiencing long interruption durations (CELID).

On December 13, 2023, PURA issued its 2023 Report to the General Assembly on Electric Distribution Company System Reliability through Docket No. 23-08-09, Annual Electric Distribution Company Reliability and Resilience Framework Review, which incorporated the new data reporting requirements from the RE08 Decision for the first time. In general, the Authority found that both EDCs reported 2022 SAIDI and SAIFI values were below the 1995-1998 and 2018-2021 four-year averages.[9] The Authority did, however, find that UI did not provide the data using the methodology as required in previous reports and failed to provide other required data related to storms in 2022. As a result, PURA has directed UI to remedy these issues by February 22, 2024.

Additionally, both EDC's CAIDI values for 2022 were found to be just above both the four-year averages. Importantly, this is not necessarily indicative of a decrease in reliability performance. Since CAIDI is the ratio of SAIDI and SAIFI, a low SAIDI and low SAIFI values (few outages and short durations) may give the same CAIDI ratio as high SAIDI and high SAIFI values (many outages and longer durations). Therefore, CAIDI must be interpreted relative to the underlying SAIDI and SAIFI values. The increase in 2022 CAIDI relative to the 1995-1998 average here indicates that SAIFI has improved at a faster rate than SAIDI (since both 2022 SAIDI and SAIFI values are improved from the 1995-1998 averages).

The below graphs, Figures 11 and 12, show the statewide SAIDI and SAIFI values from 1998-2022, respectively.

Figure 11: Statewide SAIDI Values Since 1998

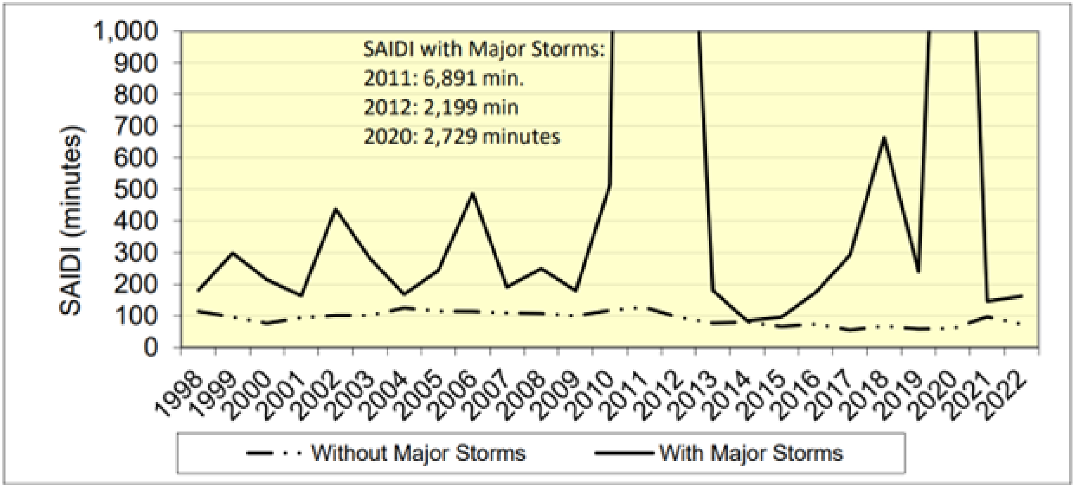
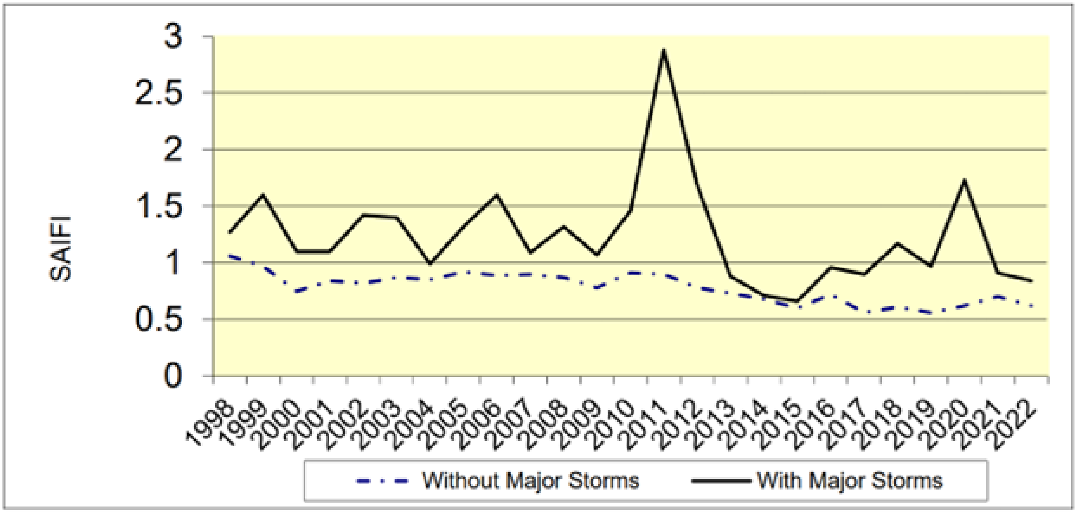


Figure 12: Statewide SAIFI Values Since 1998



Non-Wires Solutions Process

Additional Electric Reliability Reporting Resources

- 2023 Legislative Report

In 2022, PURA issued a Decision in Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives (NWS Decision), establishing a process to transparently leverage competition to identify and deploy non-wires solutions (NWS) to meet distribution system needs with the ultimate objectives of improving grid resilience and reliability, as well as improved outcomes for customers (NWS Process). As technology has changed over time, new options are available to lower system costs and improve outcomes, and specifically to avoid, defer, or reduce the cost of necessary grid investments. In addition, EDCs are now permitted by statute to own energy storage systems under a wider range of conditions than previously possible. The NWS Process enables the Authority and stakeholders to receive the necessary and appropriate information to evaluate the prudence of EDC investments, including EDC-owned energy storage.

Further, in the NWS Decision, PURA determined that the NWS Process and its policy objectives would greatly benefit from the expertise and oversight of an official PURA Process Monitor. Given the role of the EDCs in this process, oversight and transparency is key to the provision of results in the public interest. The PURA Process Monitor would act as an extension of lead staff in the annual NWS Process proceedings to supplement existing staff expertise in its oversight of the NWS Process and will provide expertise in areas in which Authority staff expertise does not currently exist. Further, given the importance of the robust stakeholder process called for by many docket participants, the PURA Process Monitor would assist in the creation of key NWS Process materials and analytical tools to provide information to stakeholders and facilitate their input.

Thus, PURA conducted a public solicitation for proposals from consultants to serve as the NWS Process Monitor in 2023. On May 4, 2023, PURA officially retained Optimal Energy (formerly identified as NV5) to serve as the NWS Process Monitor. Generally, the Process Monitor's responsibilities will include stakeholder engagement, development of NWS process materials, data review and analysis, oversight of each electric distribution company's (EDC) solicitations, and providing feedback to the Authority.

The NWS Process Monitor began the NWS Process Initiation phase identified in the NWS Decision in the second half of 2023. As part of the phase, the NWS Process Monitor has organized monthly stakeholder meetings to develop, discuss, and revise several key deliverables necessary for the NWS Process to begin in 2025. These key deliverables include, but are not limited to, the following items being developed by the Process Monitor:

- Any additional requirements and format for the annual Grid Needs Filing;
- NWS solicitation benefit-cost analysis model and process;
- Timelines for competitive NWS solicitation processes;
- Applicability of the existing regulations regarding codes of conduct for EDCs and their affiliates and any additional policies and protections needed to allow EDC affiliates to submit a competitive NWS bid;
- Plans for ongoing market engagement activities and RFI documents; and
- A standard set of data to be provided to prospective NWS solicitation bidders, which shall include, at a minimum, the information listed in Exhibit C and any relevant information from the EDC Data and Grid Needs Filings.

The NWS Process Initiation Phase also includes review, discussion, and potential modification to deliverables being developed by the EDCs, including but not limited to:

- A standard cybersecurity data access policy and pre-approval process, including non-disclosure agreements (NDAs) and data security agreements (riders) that specify vendor security requirements;
- The standard RFP to be issued by the EDCs for a NWS solicitation, inclusive of any processes to screen and qualify bidders, which shall include relevant information from the cybersecurity data access policy; and
- The pro forma contract for NWS bidders to execute with the EDC upon selection, including performance criteria and EM&V plan.

In 2024, the Process Monitor will continue to convene monthly stakeholder meetings to develop, review, and revise the above deliverables. Ultimately, the above deliverables are required to be submitted to the Authority by June 1, 2024 in Docket No. 24-08-08, Non-Wires

Additional NWS Process Resources

- Process Monitor Work Plan
- 24-08-08 Notice of Proceeding

Solutions Process Initiation Phase. After submission, the Authority will formally review and request written comments on these deliverables, ultimately issuing a Final Decision regarding NWS Process implementation in that proceeding in the second half of 2024, in order to enable the NWS Process to formally begin in January 2025.

Front-of-the-Meter Storage Pilots

Public Act 22-55, An Act Concerning Energy Storage Systems and Electric Distribution System Reliability, states that the Authority shall direct the EDCs to submit up to three proposals for energy storage system (ESS) projects with the "purpose of demonstrating and investigating how energy storage systems can improve resiliency of critical infrastructure and improve reliability of the electric distribution system."

On September 14, 2022, the Authority issued an Interim Decision in Docket No. 22-06-05, PURA Implementation of Public Act 22-55, (Interim Decision) establishing the requirements for the ESS proposals and directed the EDCs to file such proposals. Because the term "critical infrastructure" was not defined in Public Act 22-55 or elsewhere in statute, the Authority ruled that it would consider any facilities included in the EDC's emergency response plan, facilities identified by municipalities in conjunction with the EDC, or facilities that otherwise meet the Connecticut Division of Emergency Management and Homeland Security (DEMHS) definition. To enable the evaluation of the resilience benefits of the proposed ESS projects, the Authority required the EDCs to submit a "Resilience Needs Assessment" of the critical infrastructure and a description of the ESS' resilience operational strategy.

In addition to improving the resilience for critical infrastructure, the ESS projects are required to improve distribution system reliability. To identify the reliability improvements of a proposed ESS project, the Authority required specific details regarding the reliability needs of the infrastructure being served, the functionality of the ESS to address those needs, and how the EDC will dispatch the system to optimize that functionality under various scenarios.

The final element for assessing a proposed ESS project is determining whether the project "provides value to ratepayers." The Authority established certain requisite technical criteria for a proposed ESS project to be commercially functional. In addition, the Authority established a Benefit-Cost Analysis model to ensure that ratepayers receive value from the proposals that exceed the costs.

The EDC's submitted proposals in December 2022, which ultimately required supplemental analysis on wholesale energy market participation and possible ESS operation strategies for PURA to complete its assessment. The EDCs submitted this supplemental data on June 1, 2023. Following stakeholder and Authority review of the proposals, PURA issued a Final Decision on the EDCs' proposed ESS projects on December 20, 2023.

United Illuminating's Projects

United Illuminating submitted proposals for projects in Bridgeport, North Haven, and New Haven. The Authority found that the Company's proposals meet the requirements set forth in the Interim Decision and are expected to increase the resilience of critical infrastructure, improve the reliability of the distribution system, and provide value to ratepayers, if constructed and operated as proposed. Project details are summarized in Table 9 below.

Table 9: United Illuminating ESS Project Proposals

Project Location	Project Size	Critical Infrastructure Served	Features	PURA Ruling
Bridgeport, CT	2.3 MW/ 5.5MWh	Three, 9-story elderly housing facilities	Microgrid expansion to provide outage support to an additional 598 customers for at least 4 hours	Approved
North Haven, CT	1.5MW/ 4MWh	Senior living care facility with outpatient and rehabilitative services	Microgrid expansion to provide outage support to an additional 166 customers for at least 4 hours	Approved
New Haven, CT	2.5MW/ 7MWh	Magnet high school that also serves as the community emergency shelter	Microgrid expansion to provide outage support to an additional 166 customers for at least 4 hours	Approved

Additionally, the Authority applauded UI's extensive engagement with its local communities in developing their ESS proposals. UI included significant input from community leaders in its proposals, helping lead to high-value proposals for those communities. Additionally, the Authority was pleased to find that UI identified key learning opportunities and demonstration objectives, and exhibited a willingness to investigate how ESS can improve the reliability and resilience of critical infrastructure and maximize the ESS' value through secondary applications. In general, the Authority appreciates and encourages future application of UI's approach to tailoring its proposed solutions to the needs of the communities they serve, as well its adherence to the statutory intent of Section 2 of Public Act 22-55 and the Authority's specific direction and recent guidance on other matters.

Eversource's Projects

Eversource submitted projects located in Voluntown, Sherman, and Winchester.

Unfortunately, the Authority's review of these proposals resulted in denying all three without prejudice. Eversource did not demonstrate sufficiently that these projects would provide value to ratepayers. Specifically, Eversource has not adequately justified that the ESS nameplate capacity is warranted and that the projects will be undertaken at a reasonable cost. Finally, the Authority found that Eversource's operational strategy will not maximize benefits to ratepayers. Therefore, in order to receive Authority approval, the Authority directed Eversource to resubmit proposals to address the Authority's findings by May 31, 2024.

Federal Funding Requirements

The EDCs are permitted to recover prudently incurred costs for approved ESS pilot projects proposed pursuant to Public Act 22-55 through a fully reconciling component of electric rates for all customers until the company's next general rate case, when costs would be incorporated into base distribution rates. The EDCs can, and should, also seek federal funding for which they are eligible in order to offset ratepayer costs.

In November 14, 2023, the U.S. Department of Energy (DOE) announced up to $3.9 billion of available grants in the second round of the Grid Resilience and Innovation Partnerships (GRIP) Program. The ESS proposals may be eligible for federal funding under the GRIP Program Grid Resilience Utility and Industry Grants. This funding supports grid modernization efforts by investing in the deployment of advanced technologies including DERs and storage systems that can mitigate multiple hazards across a region or within a community.

Thus, PURA directed the EDCs to apply for the second round of funding available through the DOE's Grid Resilience Grants program. Concept papers for this funding opportunity were due at 5:00 p.m. ET on January 12, 2024. The Authority directed the EDCs to report on progress made seeking the above federal funding opportunities (e.g., the filing of a concept paper) and any results provided by the U.S. DOE as compliance in the proceeding within three business days of any submissions or receipt of any correspondence from U.S. DOE. UI has confirmed, via a compliance filing on January 17, 2024, that it successfully submitted a proposal to DOE for funding of the New Haven ESS project. The Authority will continue to monitor the deployment of all three UI projects, and any associated federal funding awards.

Advanced Metering Infrastructure

In 2019, the EMG Interim Decision identified advanced metering infrastructure (AMI) as essential to achieving the objectives of a modern electric grid for Connecticut. AMI is a tool available to the EDCs to better understand, plan, and operate their system, but that same information is also important to customers and market-based opportunities to help customers better manage their consumption and save money. Specifically, AMI enables a number of functions that conventional utility meters cannot provide including automatic measurement of granular energy usage data, remotely identifying and isolating outages, and monitoring voltage. These functions unlock a whole host of new customer offerings such as time-of-use energy rates or advanced rates for EVs, greater control over energy consumption using smart technology, and load-shifting. For utilities, AMI allows reduced costs related to metering and billing, better visibility of the grid and power quality, faster outage restoration, and improved operations efficiency.[10] AMI will accelerate the modernization of Connecticut's electric grid in numerous innovative, cost-effective, and equitable ways.

Today, about 90% of customers in UI's territory have AMI. The AMI deployment in UI's territory has allowed the company to realize many operational benefits such as remote meter reading, service order automation, proactive outage planning, storm restoration efficiencies, the validation of resilience/reliability measures, early outage detection, system planning optimization, energy theft reduction, provision of detailed billing data, rate design, enhanced online portals, high-bill alerts, outage status, customer targeting for initiatives, and reduced billing-related calls to the call center. UI expects that the benefits will continue to accrue for the listed categories and expects the benefits to increase as the remaining Automatic Meter Reading (AMR) meters are replaced and as the features of AMI meters and systems are available that can provide load disaggregation, load balancing, voltage monitoring, and voltage reduction.

In Eversource's territory, however, more than 75% of Eversource's customers still have standard meters (AMR meters) that are 20 or more years old. The other 25% have "bridge meters" that work with the AMR meters but can be enabled to work with an AMI system. To support AMI, Eversource would not only need to install meters, but it would also need to install and integrate the following with meters and existing systems: communications systems; back-office systems; meter data management; and customer information systems. Unlike UI, where significant investment has already taken place, Eversource needs to conduct significant levels of investment to implement AMI.

As such, achieving statewide deployment of AMI and the realization of its associated benefits will require significant capital investment from ratepayers. After three years of tremendous public process in Docket No. 17-12-03RE02, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Advanced Metering Infrastructure, including numerous opportunities for stakeholder input, guidance from industry experts such as federal agencies, peer jurisdiction utilities, and technology providers, PURA released a framework for the deployment of AMI through a final Decision on January 3, 2024. This framework provides a regulatory roadmap for the EDCs, protects ratepayers, and ensures that the investment in AMI will advance the economic, energy, and environmental policy goals of Connecticut. Importantly, this Decision outlined a process to assess the prudence of any costs associated with the deployment of AMI in accordance with the outlined framework during the EDCs' future, respective contested rate proceedings.

The AMI framework implements the regulatory goals and priority outcomes outlined by the PBR Decision discussed in Section 2. With respect to AMI, the main regulatory goals are (1) Excellent Operational Performance and (2) Customer Empowerment and Satisfaction. The AMI-specific priority outcomes for Excellent Operational Performance and Customer Empowerment and Satisfaction are distribution system utilization and customer empowerment, respectively. The Decision then identifies numerous metrics to measure an EDC's progress in deploying AMI and demonstrating that the infrastructure is providing service to customers. Additionally, the EDCs are therefore expected to work towards achieving these regulatory goals and priority outcomes, while taking into account certain foundational considerations when advancing toward the outcomes, including, safety, equity, economic opportunity, risk distribution, and transparency.. With respect to AMI, the main regulatory goals are (1) Excellent Operational Performance and (2) Customer Empowerment and Satisfaction. The AMI-specific priority outcomes for Excellent Operational Performance and Customer Empowerment and Satisfaction are distribution system utilization and customer empowerment, respectively. The Decision then identifies numerous metrics to measure an EDC's progress in deploying AMI and demonstrating that the infrastructure is providing service to customers. Additionally, the EDCs are therefore expected to work towards achieving these regulatory goals and priority outcomes, while taking into account certain foundational considerations when advancing toward the outcomes, including, safety, equity, economic opportunity, risk distribution, and transparency.

Key components of the framework are a comprehensive list of benefits that AMI can provide to make business operations more efficient, improve system utilization, and increase customer engagement with energy usage, all of which help advance the goals of the Equitable Modern Grid Framework. The framework also identifies investments and costs necessary to enable the benefits so that the evaluation of the costs and benefits can be evaluated transparently. For each benefit and cost stream, the Authority has outlined a set of metrics that the Authority will require the EDCs to report on through the use of scorecards to monitor both the deployment and implementation of AMI. The goal of the scorecards is to provide transparency and accountability for the ongoing AMI investment. Scorecards will be filed semi-annually, starting six months following submission of an EDC's final AMI plan.

For next steps, the Decision provides guidance regarding the EDCs' submission of a Final AMI plan. Each Final AMI Plan must include required information tied to the identified AMI benefits and costs outlined in the Decision, implementation and deployment plans, a benefit-cost analysis using the Authority's approved design, demonstrated evidence of competitive procurements for AMI technology components that maximize AMI's potential and value to ratepayers, updated proposals for time-of-use rates, and a customer outreach and engagement plan. The Authority also required that the EDCs make every effort, both now and in the future, to identify federal funds or other financing options that can offset the costs associated with implementing AMI.

AMI Cost Recovery

During the proceeding, Eversource stated that the company requires a clear, reasonable, and certain cost recovery path to move forward with an AMI investment. In its current AMI Plan, Eversource proposes approximately $400 million of capital investment over the first five years of AMI deployment (approximately $80 million per year). Eversource claims that due to both the level of costs and the short timeline with which they are to be incurred, it is necessary that cost recovery be granted at defined intervals during the deployment window outside of a general rate case, such as through the annual RAM proceedings.

The Authority recognizes that the anticipated capital costs outlined above, while not entirely incremental, may be significant and incremental relative to the business-as-usual core business investments. The costs are also largely concentrated in a five-year deployment period. Taken together, these factors may potentially necessitate consideration of an extraordinary ratemaking measure, such as the implementation of an annual cost reconciliation mechanism. Given this, the Authority initiated a docket simultaneously to releasing the AMI framework decision, titled as Docket No. 17-10-46RE04, Application of the Connecticut Light and Power company d/b/a Eversource Energy to Amend its Rate Schedules – AMI Cost Recovery. This is a contested proceeding that will consider the development and adoption of an AMI cost recovery tracker. In the course of that proceeding, the Authority will consider an appropriate structure of a cost tracker that allows the company to cover their prudently incurred costs while providing appropriate protection to the public interest. The schedule for this proceeding ensures that a ruling will be issued by November 20, 2024, which provides sufficient time for Eversource to include in its 2025 RAM filing a request for cost recovery of any applicable 2024 costs, if so authorized.

Additional AMI Resources

- AMI Final Decision
- Cost Recovery NOP

Progress Growing the Green Economy

Innovative Energy Solutions (IES) Program

Innovation is a natural complement to modernization; one that can, if harnessed, greatly enhance the benefits and services delivered to ratepayers. With the increase of data availability, grid-edge visibility, and distributed energy resources comes significant opportunities to optimize the grid, its resiliency and reliability, and the customer experience. However, the risk and uncertainty of requiring utilities to conduct traditional research and development or even to pilot new technologies or applications can often be too great to consider the expenses prudent. So, conventional strategies often continue to be implemented, even though novel and emerging options show promise to lower costs and/or improve service.

The Authority issued a decision in Docket No. 17-12-03RE05 on March 30, 2022, officially approving the program design of the Innovative Energy Solutions Program (IES Program). The goal of this program is to enable the deployment of, on a limited basis, innovative pilot technologies, products or services, and to evaluate their performance. If satisfactory ratepayer benefits are demonstrated, the innovation(s) could be scaled up for statewide deployment by the EDCs.

There are two features of this program that distinguish it from other pilots or test beds. The first is that it employs guardrails and project "off-ramps" to ensure value and to minimize ratepayer risk. The IES Program is structured into four phases, where potential innovations are reviewed with increasing scrutiny to ensure that their product or service meets the needs of Connecticut's grid and ratepayers and can deliver their claimed benefits or value at scale. If a project cannot meet the criteria and thresholds at a certain phase, the Authority will be able to quickly retire the project, thereby avoiding unnecessary risk and costs to ratepayers.

The second feature addresses the inverse situation where a pilot project demonstrates substantial ratepayer and grid benefits. In this case, the IES program provides a clear pathway by which to move a successful pilot project to full-scale deployment across the state's two largest EDCs' territories, which the traditional approach to EDC pilots have lacked nation-wide to date. This ensures that successful pilots are brought to scale, thereby delivering the benefits of innovation to all ratepayers.

The IES Program also places a high value on transparency, which is achieved through the external Innovation Advisory Council (IAC) comprised of a representative set of stakeholders, who would have a responsibility for ensuring a balanced perspective in the IES program.[11] Though the Authority is the primary entity responsible for developing, administering, and managing the IES Program, and retains ultimate decision-making authority over aspects of program design and project selection, the IAC provides a forum where potential participating innovators can engage and discuss the program without violating the standard communications rules with PURA. Additionally, the IAC will set the themes and objectives for each annual Program Cycle and will screen projects through the first two phases.

IES Cycle 1

The first IES Program Cycle officially launched on January 31, 2023, in Docket No. 22-08-07, Innovative Energy Solutions Program Cycle 01. Each program Cycle focuses on a selected "theme" around which projects are solicited, but does not exclude proposals that fall outside that theme. The theme is discussed and voted on by the IAC with consideration from the EDC's joint grid and customer needs reports, as well as other ongoing state policy and priority goals. The Cycle 1 theme focused on Demand-side Flexibility, which includes, but is not limited to, advanced forecasting, automation, flexible winter peak technology, and thermal storage.

Interested innovators were able to submit proposals through one of three distinct pathways: (1) developer-led projects; (2) EDC-led projects; and (3) collaborative projects. These pathways are intended to create opportunities for and encourage diverse participation from the full ecosystem of potential solutions providers and innovators.

Cycle 1 Phase 1

In Phase 1 of the IES Program Cycle 1, interested applicants were required to submit a concept proposal via the Program website, www.CT-IES.com, providing a high-level description of the proposed solution and project, by March 1, 2023. The IES Program received 52 Phase 1 applications.

The Program Administrator (Strategen Consulting), in coordination with IAC, reviewed the proposals and determined which were eligible to submit a detailed proposal in Phase 2. An IAC meeting was held to determine the final list of Phase 2-eligible projects. To be determined eligible, applicants were required to demonstrate that their project:

- Addresses current gaps in EDC offerings in Connecticut;
- Advances decarbonization;
- Addresses underserved communities in Connecticut;
- Avoids a competitive advantage for EDCs;
- Avoids an unreasonable impact to Connecticut ratepayers; and
- Will be authorized to practice business in Connecticut.

The IAC ultimately found 33 of the 52 applications to be eligible to apply to Phase 2, and were simultaneously invited to present at Pitch Fest on April 18, 2023, a live pitch event co-hosted by PURA and Connecticut Innovations. At Pitch Fest, attendees including non-decisional PURA Staff, EDC Staff, and IAC members, heard elevator pitches from applicants, had the opportunity to speak directly with applicants to learn more about their projects, and then voted for the projects they were most interested in hearing longer pitches from. Regardless of whether an applicant was selected to present a longer pitch at Pitch Fest, all Phase 2 eligible applicants were invited to submit Phase 2 applications. Phase 2 applications were provided to applicants on May 1, 2023.

Cycle 1 Phase 2

Projects invited to submit proposals in Phase 2 were required to provide detailed information regarding the project's value proposition, business and financial model, strategic alignment with the IES Program objectives, equity provisions, scalability, and project team qualifications.

The Program Administrator and the IAC then evaluated these proposals and their ability to address key criteria such as Innovation Potential, Measurable Benefits, and Focus on Underserved Communities and Equity. Descriptions of these criteria are included in Table 10 below:

Table 10: IES Phase 2 Evaluation Criteria

Category	Description
Innovation Potential	Examines whether the Proposed Project involves "testing a new product, program, tariff, service, or business model that is not widely used in Connecticut and is conducive to scaling, replication, or serving as a potential model for others to adopt or deploy."
Project Implementation Tracking Plan (PITP)	Examines whether the Proposed Project's implementation tracking plan is reasonably achievable and outlines performance metrics, data collection specifics, a timeline with stages, and milestones that are tied to cost recovery, and the frequency and detail required for progress reporting.
Project Benefits	Examines whether the Proposed Project provides measurable and sustainable benefits to society or the community, to customers, and to the EDC and electric grid.
Focus on Underserved Communities	Examines whether the Proposed Project provides measurable benefits for Connecticut's underserved communities, as that term is defined by the Connecticut Department of Economic and Community Development's (DECD) Environmental Communities and Distressed Municipalities.
Advances Decarbonization	Examines whether the Proposed Project provides measurable and sustainable benefits to support Connecticut's goals to decarbonize its electric grid by delivering zero-carbon electricity to customers by 2040 and reducing greenhouse gas emissions.
Women and Minority-Owned Business	Examines whether the Proposed Project has a Connecticut or Federal certification as a women-owned business, minority-owned business, or both. This is not a requirement, but considered a benefit.
Priority Theme	Examines whether the Proposed Project fits within the Cycle 1 theme of Demand-side Flexibility. According to the Program Administrator, the Proposed Project's alignment with the Cycle 1 theme is not a requirement, but rather a benefit.

During the Phase 2 process, all IAC members were provided an opportunity to discuss applications amongst council members and highlight follow-up questions to ask applicants. To that end, and to host a general open-forum discussion on Phase 2 applications, the IAC met on June 27, 2023, and again on July 11, 2023. The Program Administrator, on behalf of PURA Staff and IAC members, issued follow-up requests to applicants.

On July 31, 2023, the Program Administrator filed a portfolio of 8 recommended projects totaling $14 million on behalf of the IAC to the Authority for final review and approval. The Authority issued rounds of interrogatories and hosted a technical meeting where representatives of the IAC-recommended projects gave presentations and answered further questions from Authority staff.

On December 13, 2023, the Authority issued an Interim Decision in Docket 22-08-07 approving seven of the eight recommended projects for pilot deployment in Phase 3 of Cycle 1 along with the supporting justification for each project. Below are descriptions of each of the seven innovative pilot projects.

AmpUp

AmpUp proposed a project for managed EV charging by integrating its existing charging management software with utility demand response programs. This project will allow grid operators to decrease load at EV charging stations during periods of grid stress through automated participation and incentives that compensate charging station owners for decreasing charging during peak periods. The platform will also offer real-time reporting on station status and energy management controls, such as time-of-use rate setting. Additionally, AmpUp's project can further demonstrate economic benefit by managing EV charging to shift loads, which can help defer or avoid distribution infrastructure investments, resulting in savings for ratepayers.

Edo

Edo proposed an 18-month project that demonstrates how commercial buildings can provide both temporary, flexible demand management and longer-term, geographically specific load reduction. Edo aims to target 25 commercial buildings served by a single substation in a distressed municipality in Eversource's service territory. The project offers energy and non-energy benefits including energy savings, load shifting, improved health, job creation, and reduced greenhouse gas emissions.

GridEdge Networks

GridEdge Networks proposed integrating an Area Cooperative Educational Services (ACES) electric school bus in New Haven, CT, with the electric grid using Vehicle to Grid (V2G) technology and bidirectional V2G direct current fast charging (DCFC). V2G capability is an emerging technology with particularly high potential benefits given the characteristics and use patterns of electric school buses. GridEdge anticipates that the project would provide additional revenue streams to the EV fleet owner through participation in utility demand response programs, allow the EDCs to manage the bus's charging and discharging cycles, and benefit the local community by reducing air pollution and serving as a back-up power source in case of outages.

KrakenFlex

KrakenFlex proposed to use its Kraken technology platform to enroll residential customers with DERs in a new demand-side flexibility tariff program that optimizes those DERs for customer and EDC objectives. KrakenFlex's proposal is designed to automate customer and EDC participation and remove gaps in Connecticut's electric distribution system by giving UI the ability to utilize residential demand flexibility to control and optimize network connected residential DERs. This model can help further promote the sales and installation of clean technologies such as EV chargers and heat pumps by improving the cost-effectiveness of these investments. Participating customers are expected to see an estimated $100-$120 in annual bill reductions per asset.

Piclo

Piclo proposed creating a statewide flexibility market in Connecticut that can help mitigate grid constraints. The project aims to be the "eBay" of decarbonized grid flexibility by introducing a cloud-based, competitive marketplace to connect buyers of demand-side flexibility (i.e., the EDCs) with sellers of demand-side flexibility (Flexibility Service Providers or FSPs, e.g., DER owners and aggregators).Piclo's pilot will expand the portfolio of DER types and companies available to provide flexibility services and consolidate them onto a single platform, which will enable flexibility procurement transactions and provide supporting services. The pilot phase involves customizing the existing Piclo Flex product to Connecticut's grid, identifying use cases, recruiting FSPs, and determining dispatch and communication protocols with FSPs and the EDCs.Piclo has identified two FSPs prepared to enroll DERs on the platform and plans to pursue partnerships with additional FSPs.

Smarter Grid Solutions

Smarter Grid Solutions (SGS) proposed the use of Strata Grid Active Network Management Platform (Strata Grid) to integrate flexible load, energy storage solutions, and EV chargers to help UI dynamically manage grid constraints. As the use of the grid is approaching pre-set limits, Strata Grid will ensure that network limits are not violated. Strata Grid will help optimize system capacity, including increased capacity as well as expedited interconnection. Previous applications of the Strata Grid have seen 50-100% capacity improvement. Greater hosting capacity and faster interconnection could lead to increased deployment of DERs and the creation of additional in-state jobs.

Tantalus

Tantalus proposed an initiative to deploy smart computing devices, known as the TRUSense gateway, to access and control behind-the-meter DERs. The devices would provide power quality data to analyze the impact of DERs and identify vulnerable transformers. The demonstration would target about 200 homes located in an underserved community in UI service territory, of which about 100 homes would receive smart devices and behind-the-meter DERs, such as smart thermostats, smart circuit breakers, and thermal energy storage water heaters. Tantalus' project will test a strategic combination of new products to enhance benefits associated with existing demand response programs and dynamic rate performance.

Cycle 1 Phase 3

Following the Authority's December 13, 2023 Interim Decision, each project began the contracting phase with the EDCs to begin pilot deployment in Phase 3. Upon contract execution, the projects can begin deploying their technology. Using pre-determined milestones set during Phase 2, the projects will recover costs concurrent with each milestone's achievement. Each Phase 2 Applicant with a Proposed Project selected for deployment in Phase 3 is required to track and report on their metrics and milestones on a bi-monthly basis. At the conclusion of each project's pilot phase (approximately 12-18 months), the Program Administrator will prepare a final recommendation to PURA regarding whether the technology should be deployed at scale statewide. Projects that are not yet ready to scale but display promise and economic viability will have an opportunity to cycle back though the IES program with modifications in place, but this will be assessed on a case-by-case basis. Projects that do not display further potential to scale up upon assessment during Phase 4 will exit the IES program.

IES Cycle 2

The Cycle 2 proceeding will be conducted through Docket No. 23-08-07, Innovative Energy Solutions Program Cycle 2. On January 1, 2024, the IES Program began accepting proposals for Cycle 2 under the theme, "Empowering Electrification." Electrification refers to replacing direct fossil fuel use (e.g., propane, heating oil, gasoline) with electricity in a way that reduces overall emissions and energy costs. Transportation, electricity, and residential heating account for almost three quarters of Connecticut's greenhouse gas (GHG) emissions, which by 2030, must be reduced by 45% from 2001 levels.

The IES program is looking for innovative projects that can reduce barriers to clean technology adoption, electrify energy consumption, and/or develop ways to integrate and manage new and flexible loads to the electric grid.Projects that fit within the Cycle 2 Theme of "Empowering Electrification" can reduce emissions across all sectors by electrifying equipment as electricity generation simultaneously shifts towards cleaner alternatives, creating a "win-win-win" for EDCs, customers, and the environment. Examples of eligible technologies under this theme could include but are not limited to:

Figure 13: IES Cycle 2 "Empowering Electrification" Potential Projects

Pathway 1

- Lowering barriers to fleet electrification adoption.
- Platform development to facilitate transactions for customers that want to electrify homes.
- Novel behind-the-meter electrification technology.

Pathway 2

- New rates for heat pump and/or electric vehicle customers.
- Recommended modifications to support fuel switching (including cures to loss of customer if they switch from natural gas to electric equipment).

Pathway 3

- Integration of a holistic solution that enables active management of EV chargers and other customer-sited DERs to increase dynamic hosting capacity through continuous monitoring of network load and active management of flexible resources.
- Integration of smart grid technology that can improve user understanding and control of their building energy usage, and provides them with pathways towards reducing their energy usage or pivoting towards electrification.
- Location-based incentives/rates for interconnection and/or energy use, depending on grid constraints.

Importantly, the IES Program will also accept proposals that address the priorities identified in the EMG Framework. Concept proposals were due by February 1, 2024. Interested parties should visit www.ct-ies.com or contact info@ct-ies.com with any questions.

Additional IES Program Resources

- IES Program Design
- Cycle 1 Interim Decision

Click to visit the IES Portal

IES
INNOVATIVE ENERGY SOLUTIONS

2023 CLEAN & RENEWABLE ENERGY PROGRAM UPDATES

Since 2021, the Authority has prepared and released an annual report summarizing the most up-to-date and comprehensive data available regarding ratepayer-funded clean energy programs in Connecticut. This Annual Clean and Renewable Energy Report (CRE Annual Report) is designed to provide transparency and insight into the state's CRE programs and procurements for all stakeholders and state policymakers. The CRE Annual Report is also intended to be a resource for state policymakers and stakeholders when considering potential modifications to state energy policy goals. In sum, the Authority's primary objective in the CRE Annual Report is to provide open access to the data from the CRE programs that are funded by Connecticut ratepayers.

Specifically, this report provides data regarding the following CRE programs and market segments:

- Residential solar photovoltaic (PV) systems
- Non-Residential solar PV systems
- Shared Clean Energy Facilities (SCEF) Program
- Public Policy Contracts and Power Purchase Agreements (PPAs) selected through Department of Energy and Environmental Protection (DEEP) procurements
- Clean Energy Options Program (CEOP) / Voluntary Renewable Option (VRO) Program
- Renewable Portfolio Standards (RPS) Compliance
- Electric Vehicle (EV) Charging Program
- Energy Storage Solutions (ESS) Program

Beginning with the 2023 CRE Annual Report, PURA will release this report concurrently with the release of each PURA Annual Report both in its standard docket and as an appendix to the PURA Annual Report. The 2023 CRE Annual Report was released on February 14, 2024, in Docket No. 23-08-01, 2023 Clean and Renewable Energy Program Data and Report. The Authority remains committed to expanding and improving the type, quality, and presentation of the data included in the CRE Annual Report, and will seek to make incremental improvements each year, to the extent possible.

2023 Clean and Renewable Energy Report

- See Appendix 3
- Report in Docket

[1] Retail suppliers are licensed by the Authority to provide electricity generation services. See Conn. Gen. Stat. § 16-245(b).Retail suppliers' rates are posted on the EnergizeCT rate board at https://energizect.com. See Conn. Gen. Stat. § 16-244d(b); Decision, May 6, 2020, Docket No. 14-0720RE01, PURA Development and Implementation of Marketing Standards and Sales Practices by Electric Suppliers – Revised Standards, Ex. B, p. 5 ("[A]ll of a [retail supplier's] generally available rates must be posted to [energizect.com].").

[2] Conn. Gen. Stat. §§ 16-244c(a)(3) and 16244m(a).

[3] Decision, Apr. 21, 2004, Docket No. 03-01-15, DPUC Investigation into the Need for Interconnection Standards for Distributed Generation.

[4] Hosting capacity is the estimated maximum amount of energy from a distributed resource (such as solar panels) that can be accommodated on the distribution system at a given location. This capacity is under existing grid conditions and operations without requiring significant infrastructure upgrades. This capacity takes into consideration safety, power quality, reliability, or other operational criteria.

[5] Additional, specific options exist, including smart inverter setting, that can generally be categorized other reducing the project's capacity.

[6] See Appendix 3 for more information on the RRES program and its deployment data.

[7] The make-up of the working group includes the EDCs, various distributed energy resource developers, OCC, BETP, the Connecticut Industrial Energy Consumers (CIEC), and PURA EOE staff.

[8] Excluding these categories of outages helps evaluate the long-term, blue-sky reliability of the distribution system. Major storms in particular can create large variations in reliability data making year-to-year comparisons difficult and potentially misleading.

[9] The Authority includes the four-year average ending 1998 in conjunction with Conn. Gen. Stat. § 16-244i.

[10] U.S. Department of Energy, Advanced Metering Infrastructure and Customer Systems, September 2016, available at:
https://www.energy.gov/sites/prod/files/2016/12/f34/AMI%20Summary%20Report_09-26-16.pdf

[11] In 2023, the IAC membership composition included PURA, the Connecticut Green Bank, DEEP, OCC, United Illuminating, Eversource, Connecticut Innovations, CTNext and the Yale Carbon Containment Lab.

2023 GRID MODERNIZATION DECISIONS

Docket Number	Title	Decision Date
22-08-02	Annual Residential Renewable Energy Solutions Program Review – Year 2	2/8/2023
23-02-02	2023 PURA Report to the General Assembly Regarding the Electric Efficiency Partners Program	2/8/2023
22-08-01	2022 Clean and Renewable Energy Program Data and Report	2/22/2023
21-07-01	Application of The Connecticut Light and Power Company and Yankee Gas Services Company, each individually d/b/a Eversource Energy, The United Illuminating Company, Connecticut Natural Gas Corporation, and The Southern Connecticut Gas Company for Approval of Arrearage Forgiveness Program 2021-2022	9/6/2023
23-05-01	Annual Review Of Affordability Programs And Offerings (Energy Affordability Annual Review)	10/11/2023
23-08-02	Annual Residential Renewable Energy Solutions Program Review - Year 3	11/1/2023
23-08-03	Annual Non-Residential Renewable Energy Solutions Program Review - Year 3	11/82023
23-08-05	Annual Energy Storage Solutions Program Review - Year 3	11/29/2023
23-08-06	Annual EV Charging Program Review - Year 3	11/29/2023
23-08-04	Annual Shared Clean Energy Facility Program Review - Year 5	12/6/2023
22-08-07	Innovative Energy Solutions Program Cycle 01	12/13/2023
23-08-09	Annual Electric Distribution Company Reliability And Resilience Framework Review	12/13/2023

Docket Number	Title	Decision Date
22-06-05	PURA Implementation Of Public Act 22-55	12/20/2023
22-06-29	PURA Investigation Into Distributed Energy Resource Interconnection Cost Allocation	12/20/2023
23-07-02	PURA Implementation Of The Provisions Of Public Act 23-199	12/20/2023
17-12-03 RE02	PURA Investigation Into Distribution System Planning Of The Electric Distribution Companies -Advanced Metering Infrastructure	1/3/2024

A comprehensive list of PURA 2023 decisions is available in Appendix 2, attached to this Report.