Balancing Energy Affordability and Grid Resilience Under Performance-Based Regulation

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ABSTRACT

Connecticut's Public Utility Regulatory Authority ("PURA" or "the Authority"), among other state regulators, is developing performance-based regulation ("PBR") frameworks intended to tie utility earnings to measurable public outcomes. By moving away from traditional cost-of-service ratemaking, regulators aim to balance affordability, reliability, resilience, climate goals, equity, and customer experience by creating mechanisms that reward utilities for meeting state policy goals.

While the implementation of PURA's Equitable Modern Grid initiative is ongoing, this paper will focus on the early application of the Authority's Resilience and Reliability Frameworks. Electric distribution companies face mounting challenges to resilience and reliability, including increased major storm intensity and frequency, affordability, electrification, and the aforementioned new regulatory requirements.

Rigorously assessing distribution investments under PBR requires high-quality data and a clear framework to track and report performance metrics. Guided by the Frameworks, this paper fleshes out a taxonomy of distribution system investments to categorize all utility programs by the role they play in improving or maintaining system reliability and resilience, and what system need drives each investment. Then, based on the investment's role, analyses were undertaken, that included: affordability analysis, benefit-cost analysis, and least-cost best fit analysis. Methodology for each assessment is documented, and the benefits to customers and the utility are described. Readers will come away with an understanding of the goals of PBR, the challenges of early implementation, and the methodology available to quantify and report distribution system planning.

Introduction

In August 2022, the Connecticut Public Utilities Regulatory Authority issued new Resilience and Reliability Frameworks in Docket No. 17-12-RE08 ("RE08" or the "Frameworks") to guide electric distribution companies in balancing system performance with affordability. The Frameworks require electric utilities to evaluate capital investments through structured assessments of cost-effectiveness, reliability outcomes, and customer impacts. Although investments often serve both system reliability and resilience, RE08 establishes distinct analytical requirements for each. The author collaborated with United Illuminating ("UI" or "the Company") to comprehensively apply RE08's Reliability and Resilience Frameworks to all proposed capital expenses included in the Company's 2025 Rate Case Docket No. 24-10-04 (PURA 2026). UI is an Electric Distribution Company ("EDC") serving around 350,000 customers in Connecticut.

Guided by RE08 and emerging performance-based regulation principles, this paper develops a clear taxonomy of distribution system investments and describes the evaluation of each program based on its role in maintaining or enhancing system reliability or resilience. The analysis methodologies applied include affordability screening, benefit-cost analysis, and least-cost best-fit evaluation, as well as documentation of customer impacts. The Frameworks were rigorously applied to UI's 2025 – 2026 capital plan to increase transparency, quantify benefits where applicable, and support data-driven decision-making. In doing so, this report illustrates both the practical application of PURA's Frameworks and the broader challenges utilities face in balancing reliability, resilience, and affordability amid evolving regulatory expectations.

Policy Background

In 2020, the Connecticut legislature signed the Take Back Our Grid Act (CT Gen Stat § 16-244aa. 2024), directing PURA to research, develop, and implement a performance-based regulation ("PBR") framework for the EDCs. Key characteristics of PBR include revenue adjustment mechanisms that modify traditional rate-setting tools to align utility revenue with performance goals rather than cost-of-service outcomes, performance mechanisms that define how utility performance is measured and incentivized, and annual scorecards that report these metrics for increased transparency. In April 2023, PURA issued a Phase 1 Decision in Docket 21-05-15 establishing the framework and priority outcomes, including reliability, affordability, equity, and resilience. Phase 2, focused on implementation, is currently underway. A final decision is tentatively scheduled for October 2026.

In August 2022, PURA issued a final decision in its investigation into the EDCs' distribution system resilience and reliability planning, Docket No. 17-12-RE08. The Decision detailed new Resilience and Reliability Frameworks to "maintain and improve reliability and resilience of the electric distribution system, while establishing a framework to identify how to do so in the most cost-effective manner possible" (PURA 2022, 39). As such, the EDCs are required to evaluate all resilience and reliability programs using the framework to ensure a cost-effective, resilient, and reliable distribution system. To develop programs that maintain consistent top-quartile distribution reliability (represented by system-level SAIFI across the U.S.) while minimizing ratepayer impact in Connecticut, PURA's new performance targets and standards consider reliability, resilience, and cost-effectiveness, balancing performance with ratepayer costs.

RE08 defines "resilience" as the ability of the system to withstand, reduce, or mitigate the magnitude or duration of interruptions. "Reliability" is defined as the ability of the system to deliver electricity in the quantity and quality demanded by users. By this definition, all capital programs contribute to reliability. While Connecticut EDCs were previously required to report annual four-year rolling average storm and non-storm SAIFI and SAIDI metrics,[1] RE08 requires additional metrics to evaluate reliability expenditures at the time of submission, including:

- Identify reliability drivers associated with each project
- Demonstrate that the project is the most cost-effective solution for the given driver, where options exist
- The historical costs and associated reliability trends by reliability driver
- A holistic affordability analysis[2]

[1] SAIFI is the System Average Interruption Frequency Index, or average outage frequency per customer, while SAIDI is the System Average Interruption Duration Index, or the average outage duration in minutes per customer over a given period of time, typically a year. (IEEE Guide for Electric Power Distribution Indices 2012),
[2] RE08 defines an affordable plan as one that falls at or below the inflation-adjusted 10-year average expenditure.

- Incremental SAIDI or SAIFI improvement associated with specific programs where possible
- A declared reliability target of 5% improvement over the existing system-level SAIFI for any expenses over the affordability threshold, or of 0% for those below

For resilience plans:

- Identify vulnerable zones
- Identify the most cost-effective solutions to mitigate vulnerabilities
- Conduct benefit-cost analysis of proposed resilience investments

While the PBR Docket is a separate policy and still in progress, it is based on the same key objectives as RE08 – to encourage achievement of reliability targets and strengthen grid resilience in the most cost-effective manner. Further, RE08 metrics may be used to determine incentives and penalties under PBR in the future, with or without modifications to the existing targets and standards.

Reliability Methodology

Reliability programs that target day-to-day distribution system performance are typically either reactive (addressing existing issues) or proactive (preventing future reliability issues). Programs are first assessed for their role in system reliability and are included in a holistic affordability analysis. If the overall capital plan is affordable as defined by RE08, then EDCs do not need to evaluate marginal costs relative to marginal reliability benefits. Figure 1 displays the application of RE08's Reliability Framework to UI's 2025 – 2026 capital plan.

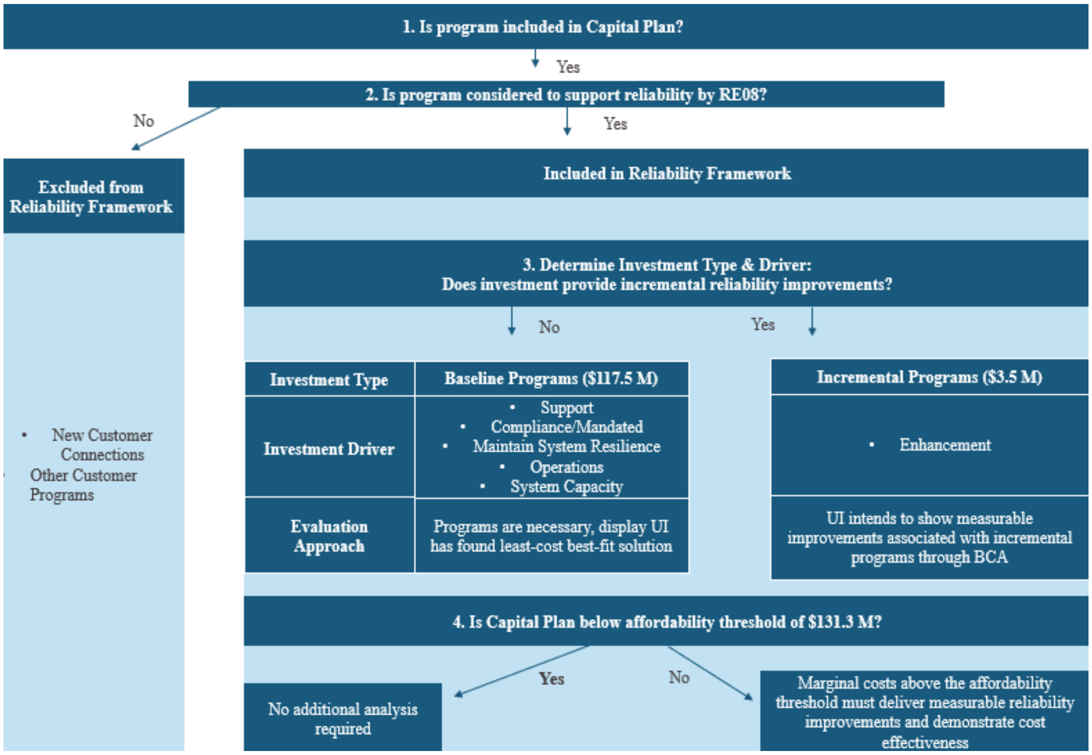


Figure 1. Summary of Applied Reliability Framework

Categorizing Capital Programs

To evaluate UI's reliability programs[3], capital programs were first split into two main categories, baseline and incremental, based on their characteristics. The U.S. Department of Energy ("DOE") Grid Modernization Laboratory Consortium recommends that, to demonstrate benefits associated with grid modernization plans, investments must first be categorized based on their function and objective, detailing how each component helps achieve overall goals (U.S. DOE 2021). A taxonomy of the Company's investments was developed using RE08's frameworks, the DOE's paper, and discussions with subject matter experts. This taxonomy helps to clarify internal company investment categories and provides a basis for comparison and evaluation in future capital plans.

Baseline Reliability Programs

- Maintain existing blue-sky reliability performance
- Budget proposals that maintain reliability must not exceed the prior 10-year average expenditures (plus reasonable escalation factors)

[3] A majority of utility programs are considered to support system reliability by RE08, so "capital programs" and "reliability programs" are used interchangeably here.

Incremental Reliability Programs

- Provide an incremental or marginal improvement to blue-sky system reliability performance
- Plans must justify any budget increases above the affordability threshold,[4] quantifying incremental benefits and costs

Reliability Investment Drivers

Distribution companies design reliability programs to mitigate various threats to system reliability and meet the needs of the system, including replacing aging assets, adding capacity, performing routine maintenance, improving poor performance, and enhancing the system. Collectively, these threats are categorized into *reliability investment drivers*: the primary motivation of each investment. While the investment driver is the primary factor that motivates each investment, there may also be secondary factors. For example, there is not always a clear distinction between reliability and resilience investments, as programs that primarily focus on mitigating storm outages may also have secondary reliability drivers and vice versa. EDCs and the Authority are jointly interested in identifying the best solution for each reliability investment driver at the lowest cost. In addition to classifying the capital programs into baseline or incremental investments, they are classified based on their respective reliability investment driver:

- Support: Programs that support the baseline mission of the EDCs to deliver electricity without directly contributing to reliability.
- Compliance/Mandated: Programs mandated to comply with policy.
- Infrastructure Replacement: To replace aging infrastructure before it fails, avoiding system interruptions.
- System Resilience: Investments that maintain the system's baseline resilience and prevent the degradation of major storm performance.[5]
- Operations: Expenditures for business operations and restoration activities.
- System Capacity: Contributes to baseline reliability by avoiding overload and facilitating the connection of distributed energy resources.
- Enhancement: Incremental programs that enhance system reliability through corrective reliability on poor-performing circuits, grid modernization programs that contribute to incremental reliability improvements, and resilience programs that enhance system resilience and reliability.

UI's internal investment categories were assessed and assigned the appropriate investment type (baseline or incremental) and investment driver in Table 1.

[4] The affordability threshold refers to the 10-year average of escalated baseline programmatic expenditures. Plans exceeding this must aim to achieve a 5% average reduction in blue-sky SAIDI and SAIFI values over the life of the corresponding rate plan, calculated from the four-year average derived from the previous Reliability Framework cycle (PURA 2022, 45-50).
[5] Programs targeting system resilience often help maintain system reliability as well. Programs aimed at improving system resilience are included in the Enhancement category, and also enhance system reliability.

Table 1. Classification of Capital Programs into Investment Type and Drivers

Investment Type	Investment Driver	Investment Category or Program
Baseline	Support	Modernization
		Business Effectiveness
		Customer Service Technology
		Facilities
		Fleet
		Metering (AMI)
Baseline	Compliance/Mandated	Compliance & Safety
		Customer Lighting
		State & Municipal
		Third Part Pole Attachments/Replacements
Baseline	Infrastructure Replacement	Infrastructure Replacement: Distribution System
		Infrastructure Replacement: Substations
Baseline	Baseline System Resilience	Coastal Substations
		Step Down Bank Removals
		Substation Getaways
		Pole loading compliance
Baseline	Operations	Operations
Baseline	System Capacity	Capacity
Incremental	Enhancement	Corrective Reliability
		Modernization: Distribution Automation, Network Buildout[6]
		Proposed Resilience Plan[7]
Excluded[8]	Customer Capex	Other Customer Programs
	New Customer Connections	New Connections

Affordability Analysis

To develop a definition of unaffordable rates to evaluate capital plans, RE08 states that a reliability program budget "…is unaffordable if it exceeds the Company's historic average annual reliability program budget, using the … annual reliability program budgets from the 10 years preceding the chosen test year and factoring in reasonable escalation factors derived from Gross Domestic Product ("GDP") Deflator index published by the U.S. Bureau of Economic Analysis" (PURA 2022, 45). The affordability analysis was conducted in aggregate, by investment type, and investment driver. All reliability capital expenditures must be evaluated through RE08's affordability analysis. If a multi-year plan exceeds the affordability threshold,

[6] No incremental modernization projects were proposed in the 2025 – 2026 rate case.
[7] A separate report prepared by the author applied the Resilience Framework to investments that provide incremental benefits during major storms, as required by RE08 (Smith et al. 2024). The methodology is described later in this report.
[8] Several programs or categories are excluded from this report due to their unique roles in UI's distribution system. New Customer Additions and Customer Capex programs are not planned for traditional reliability reasons and are excluded from the Framework (PURA 2022, 46).

the Company must demonstrate cost-effectiveness by quantifying incremental benefits, costs, and reliability improvements. The intent is to demonstrate the function of each program in maintaining or improving reliability, as well as setting up an analysis paradigm for use in future rate cases, for ease of evaluation and comparison.

While RE08 directs utilities to escalate historical capital expenditures using the GDP Deflator[9], alternative indices may better reflect distribution-specific cost trends. The GDP Deflator measures economy-wide price changes across personal consumption, investment, government spending, and net exports, but does not capture the regional and sector-specific cost pressures faced by northeastern EDCs (U.S. BEA 2024, PJM 2024). In contrast, the Handy-Whitman Index of Public Utility Construction Costs tracks regional electric utility construction costs by FERC account, including distribution-specific categories such as poles, conductors, transformers, meters, and station equipment (PJM Interconnection 2024). As a result, the Northeast distribution plant Handy-Whitman Index more accurately reflects inflation experienced by EDC capital programs, whereas the GDP Deflator reflects broader national economic conditions.

Since 2014, the Handy-Whitman Index has shown significantly higher inflation than the GDP Deflator, with the gap widening after COVID-19 due to supply chain constraints and sharp increases in utility input costs (Motyka et al. 2022; U.S. DOE 2022). At the same time, Connecticut's median and average household incomes rose by approximately 26% between 2014 and 2022, outpacing the GDP Deflator and suggesting that local affordability metrics may better reflect customer impacts (U.S. Census Bureau 2022). Similarly, Crowley et al. found that distribution capital input costs have increased substantially faster than customer rates (2024). Relying solely on the GDP Deflator to escalate capital costs therefore understates utility-specific inflation and may artificially suppress the affordability threshold, potentially discouraging necessary investment in Connecticut’s electric distribution infrastructure. Ultimately, the Authority agreed that the Handy-Whitman Index better reflects utility costs (PURA 2026, 45). Future applications will likely utilize both indices to reflect both perspectives. Figure 2 displays the GDP Deflator and Handy-Whitman Index percent inflation from 2014 to 2024.

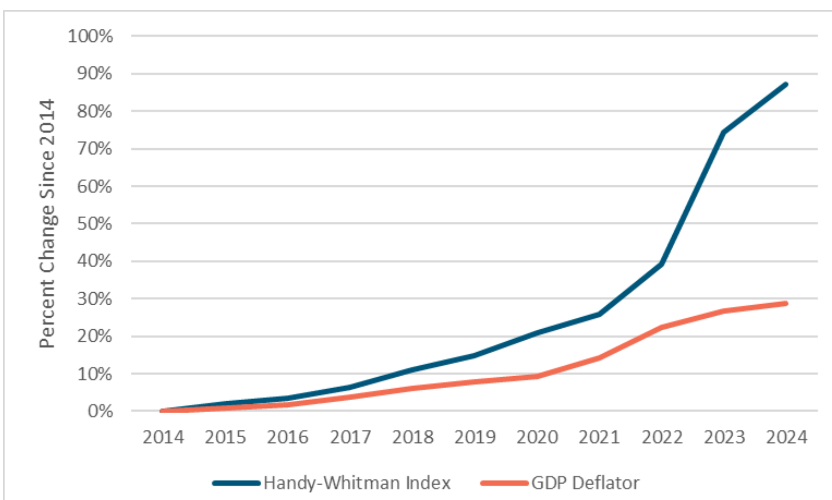


Figure 2. GDP Deflator and Handy-Whitman Index Calculated Inflation 2014 – 2024

[9] Published by the U.S. Bureau of Economic Analysis.

Justifying Reliability Investments

Because many reliability investments—such as infrastructure replacement, capacity upgrades, or required system support functions—must be undertaken to maintain baseline performance, traditional benefit-cost analysis ("BCA") is not always appropriate. In other instances, like IT support or fleet, the programs support the reliability of the system without a way to tie them directly to SAIFI improvements. Where the need for an investment is established, UI applied a least-cost-best-fit ("LCBF") approach to identify the lowest-cost option to meet reliability requirements. The DOE's Grid Modernization Laboratory Consortium states that LCBF should be applied in distribution grid planning when the need for an investment has been established, such as when a specific standard needs to be met (2021). In LCBF, different options are considered to meet the need or investment driver to determine the option with the lowest cost.

A BCA is used on a forward-looking basis to evaluate the net benefit of the investment to customers and the utility, reserved for incremental programs expected to produce measurable improvements in reliability over the historical baseline. While an incremental Resilience Plan and continued work on corrective reliability were proposed in the plan, no substantial incremental reliability improvements are expected over the one-year rate case, running from fall 2025 to fall 2026. In this context, a BCA would be used to evaluate incremental programs to identify if SAIFI and SAIDI improvements to customers outweigh the cost of the investment. However, the 2025-26 rate case did not incorporate incremental reliability investments.

In accordance with RE08, programmatic expenses by reliability driver are displayed alongside their reliability impact, to the extent possible, to ensure that ratepayers are realizing a return on their continued investment

Resilience Methodology

To implement RE08's Resilience Framework, UI engineers first identified nine priority distribution circuits for resilience upgrades using a structured prioritization matrix. They then developed three distinct resilience proposals for the selected circuits, which the author evaluated for cost-effectiveness. The most cost-effective solution set was proposed and rejected in Docket No. 22-08-08. UI re-proposed the plan in its 2025–2026 capital plan, which was approved, with execution of the Resilience Plan scheduled for 2026–2031.[10] Although the Resilience Plan benefits will not be realized over the one-year rate case period, it aims to improve storm performance, and a BCA is required to determine whether customer benefits outweigh upgrade costs.

Identify Vulnerable Zones

RE08 directs EDCs to identify "vulnerable zones" for resilience investment. All of UI's distribution circuits were ranked using a weighted scoring matrix based on:

- System SAIFI and SAIDI
- Vegetation exposure

[10] As the Resilience Plan is scheduled for 2026 – 2031, only engineering costs were included in the 2025 – 2026 capital plan and therefore subject to the Resilience Framework. This analysis evaluated the Plan wholesale for the life of the assets.

- Circuit length and customer density
- Municipal and environmental justice considerations
- Customer count and commercial/industrial load
- Overhead tie points and mainline circuit length
- Average customers per recloser

Each factor was rated low, medium, or high risk and weighed to select the nine circuits most vulnerable to major storms, collectively "resilience circuits". This process identified which circuits receive investment in the proposed Resilience Plan.

Identifying Resilience Investments

In order to find the most cost-effective resilience solution for the identified resilience circuits, three proposals were assessed for each circuit.

- **Proposal 1:** Includes mixed automation and topology upgrades and is the lowest-cost solution for each circuit. Measures included installing reclosers, line switches, cutouts, small sections of aerial or underground cable, and switching portions of the load to a different circuit. These measures reduce customers impacted by outages, enable restoration of certain zones, reduce customer count on a given circuit, and facilitate right-of-way removal.
- **Proposal 2:** The second most costly proposal: includes all solutions put forth in Proposal 1, with added hardening efforts, including upgraded express portions of the line to aerial or underground cable, which increases resilience to extreme weather and other hazards.
- **Proposal 3:** The costliest proposal: hardens the whole mainline of the circuit through transitioning to underground cable. Proposal 3's undergrounding is stand-alone and does not build upon measures proposed in Proposals 1 or 2.

Justifying Resilience Plan

In assessing each proposal, avoided customer interruption costs and avoided restoration costs were included as benefits. Avoided customer interruption costs reflect the reduction in costs from reducing the frequency and duration of outages. They were estimated using historical UI outage data and Lawrence Berkeley National Lab's Interruption Cost Estimate model (2018). Avoided restoration costs reflect reduced utility capital and O&M costs due to fewer outage restoration activities.

Historical outage data (2019–2023) was used to develop a baseline of outages and associated avoided costs. To account for uncertainty, one BCA scenario assumed future outages look like historical outages in frequency and duration, while a second scenario increased storm outage frequency to double that of the historical database. Engineering simulations estimated the percentage of outages prevented by hardening measures and the reduction in duration due to automation and topology measures. Automation benefits were limited during "concurrent outages" (e.g., system-wide interruptions), when switching options may not function. Hardening benefits were applied to the baseline first, as they prevent outages; automation benefits were applied to shorten the remaining outages to avoid double-counting.

To reflect the expected life of the assets, hardening benefits were modeled for 30 years and automation/topology for 20 years. The expected useful lives used are based on engineering realities.

Capital costs of the proposals and benefits were compared using appropriate discount and escalation rates, resulting in benefit-cost ratios for each proposal and resilience circuit. By comparing solutions at the circuit level, the most cost-effective solution set was identified and proposed in the rate cases.

Results

System Reliability Trends

As acknowledged in RE08, the Company's historical expenditure on capital programs has directly contributed to the top-quartile reliability experienced by customers (as measured by SAIFI and compared across the U.S.). This section ties reliability metrics to historical programmatic costs. In addition, system-wide and town-level reliability metrics are presented.

Table 2 displays total historical spend by investment driver and total system reliability metrics for applicable outages from 2014 to 2023. Investment drivers were mapped to UI's historical outage database to identify aggregate all-in system SAIFI and SAIDI from 2014 to 2023. The goal of presenting this table is not to tie specific reliability projects to overall system reliability performance, but instead to use system SAIFI and SAIDI as the best available proxy to assess the reliability contributions of specific projects. A larger system SAIFI per cost and system SAIDI per cost reflects a more efficient program, or more outages targeted by programs within a given investment driver per dollar spent. Notably, the largest SAIFI per dollar is associated with replacing aging infrastructure, followed by incremental reliability enhancements, and projects that support baseline system resilience.

Table 2. Historical Reliability Metrics and Expenditure by Investment Type & Driver

Investment Type	Investment Driver	2014-2023 Capital Expenditure (Unadjusted $ in Thousands)	System SAIFI (All) / Thousands of $	System SAIDI (All) / Thousands of $
Baseline	Infrastructure Replacement	$342,421	0.0072	0.0364
	System Capacity	$10,370	0.0025	0.0045
	Operations	$132,209	N/A	N/A
	Support	$265,246		
	Compliance/Mandated	$172,272		
	System Resilience	$101,219	0.0476	0.6185
Incremental	Enhancement	$93,461	0.0516	0.6698

Reliability metrics reflect the sum of SAIFI and SAIDI from 2014 to 2023. Infrastructure Replacement included the following outage causes: company equipment (OH), lightning, and company equipment (UG). System Capacity included overloads. System Resilience and Enhancement included all outages excluding planned, non-utility control, operating error, and customer equipment, line fuse, and transformer.

Figure 3 displays blue-sky SAIFI performance from 2014 to 2023. Due to UI having a small customer population and relatively low SAIFI, year-over-year variation is typically attributed to the addition or absence of a single large outage event (often company equipment failure, vegetation impact, and motor vehicle accidents). For instance, in 2023, a substation failure resulted in 26,687 customer outages and a 0.08 increase in SAIFI, highlighting the importance of UI's baseline reliability programs. Overall, UI's system-level blue-sky SAIFI has varied within a narrow range around 0.50, or half of an outage per customer-year, below the system target of 0.64 set forth by Docket No. 86-12-03. This trend reflects low historical investment in incremental programs and adequate investment in baseline maintenance programs, holding SAIFI performance relatively steady.

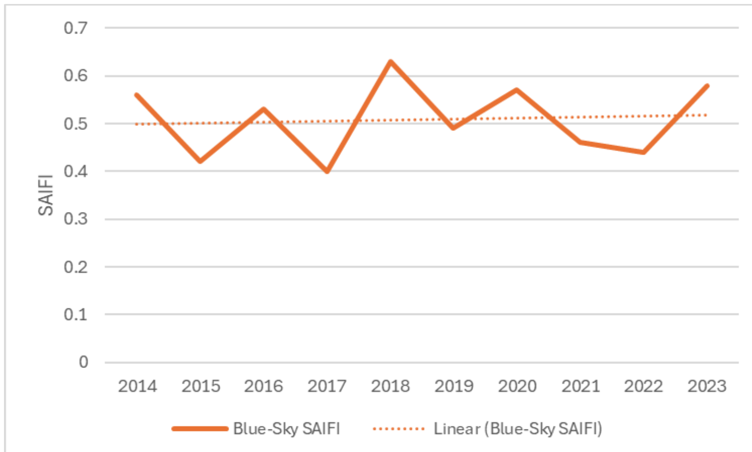
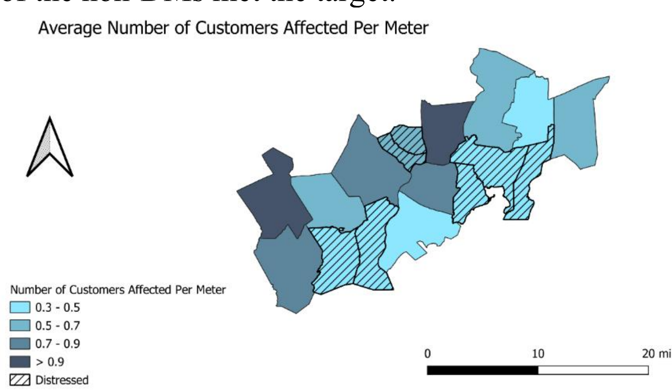


Figure 3. Blue-Sky SAIFI Trend 2014 – 2023

In order to ensure an equitable and modern grid for all customers, reliability trends were evaluated by town within UI's service territory. UI serves 17 towns in Connecticut, seven of which are Distressed Municipalities ("DMs") as defined by the Connecticut Department of Economic and Community Development (2024). DMs are selected to identify the state's most economically stressed towns. Utilizing the count of meters by town, the team identified that roughly 58% of UI's meters are located within DMs. To summarize reliability trends by town, Figure 4 displays the average annual customers affected by outages per meter by town within UI's service territory.[11] All DMs had 5-year average blue-sky SAIFI levels below the target of 0.64, while only half of the non-DMs met the target.



[11] The count of interruptions is derived from the average annual customers affected from 2019 – 2023 and then normalized by the count of meters to approximate blue-sky town-level SAIFI.

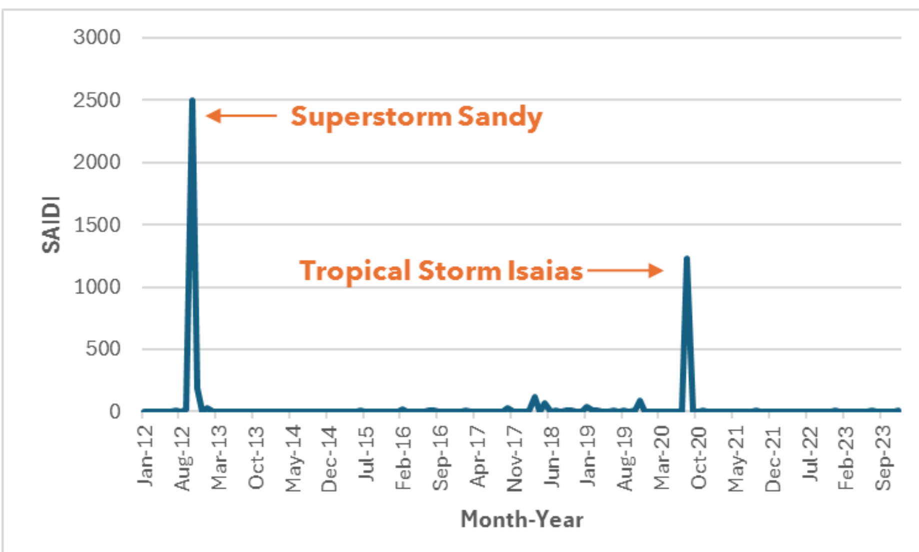
Figure 4. Average Non-Storm SAIFI by Town 2019 - 2023

Affordability Analysis

UI's November 2025 – October 2026 capital plan of $121.0 million was "affordable", falling 7.9% below the GDP-inflated $131.3 million affordability threshold. Of this total, $117.5 million is designated to baseline programs that maintain existing system reliability, while $3.5 million (2.9%) funds incremental programs intended to improve performance beyond historical levels. Historically, approximately 8.5% of reliability spending targeted incremental improvements, indicating that the current plan is primarily focused on sustaining UI's high baseline reliability. Because the plan is below the affordability threshold, RE08 permits a 0% reliability improvement target and does not require a formal benefit-cost analysis to justify reliability expenses above the threshold.

System Resilience Trends

Figure 5 displays the SAIDI for only major storm outages by month from 2012 to 2023.[12] In October 2012, Connecticut was affected by Superstorm Sandy, during which UI customers experienced a monthly SAIDI more than two times greater than the next largest storm event in the last 10 years. In August 2020, UI experienced large storm-related outages during Tropical Storm Isaias. Historical UI outage data shows that very large storm events have occurred approximately once every five years. The difference in customers impacted between Sandy and Isaias is quite large, and storm SAIDI ranges from 0 in months with no storm-related outages to 2,500 outage minutes (1.74 days) per customer during Sandy. This underscores the significant potential for benefits to customers by mitigating the impacts of a single storm of the magnitude of Superstorm Sandy in the next 30 years.



[12] This figure excludes outages that were planned or system-wide.

Figure 5. Major Storm Monthly SAIDI 2012 - 2023

Cost-Effective Resilience Plan

Applying any of the three resilience proposals uniformly to all nine circuits did not result in a cost-effective solution. Instead, the team identified the most cost-effective option for each circuit individually, resulting in a mixed portfolio of automation, selective undergrounding, and overhead hardening. Figure 6 compares the benefit-cost ratios of each of the three proposals applied to all nine circuits, compared to the optimal solution set. The figure also displays the total cost of each proposal and the benefit-cost ratios under each storm scenario. The optimal solution set is cost-effective over 30 years under the baseline storm scenario, with a benefit-cost ratio of 1.00. Under the escalated storm scenario, the optimal solution set has a benefit-cost ratio of 1.56. Under conservative storm assumptions, the estimated SAIDI reduction is 0.6 hours per customer per year. Assuming more storms occur in future years, the estimated SAIDI reduction is 0.91 hours per resilience circuit customer per year. The optimal solution set was proposed as UI's 2026 – 2031 Resilience Plan.

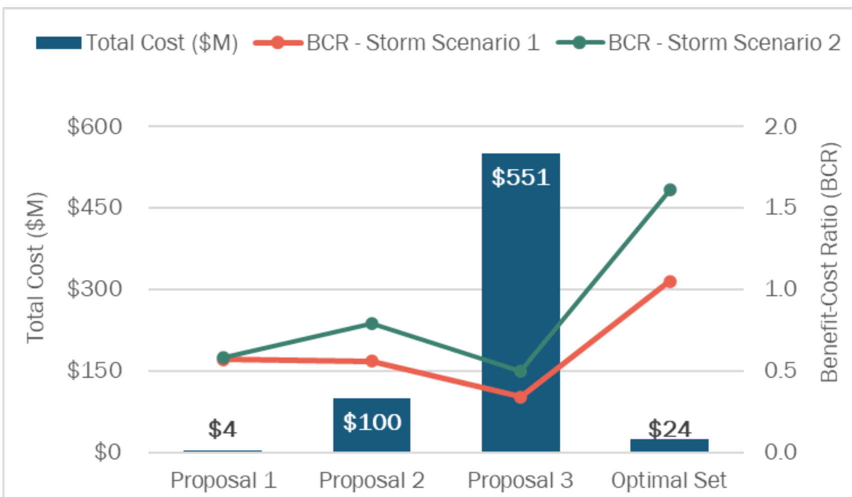


Figure 6. Comparison of Resilience Proposal Cost-Effectiveness

Further, the Resilience Plan benefits were examined to ensure they flow to Distressed Municipalities. The avoided outages and corresponding avoided outage costs were mapped by town.[13] Four of the towns where the Resilience Plan will take place are DMs. While four of the nine circuits serve DMs, approximately 19.7% of average annual (base) customer interruption costs from 2019 – 2023 occurred in DMs.

Figure 7 shows the estimated average annual percent reduction in customers affected by outages each year due to the Resilience Plan. Grey-shaded towns are not included in the Resilience Plan. The four DMs are estimated to receive 40.2% of the avoided customer

[13] The relationship between circuit and town is not one-to-one. For instance, a circuit can cover multiple towns and there are typically multiple circuits within a given town.

interruptions and 22.8% of the avoided customer interruption hours expected from the Resilience Plan.

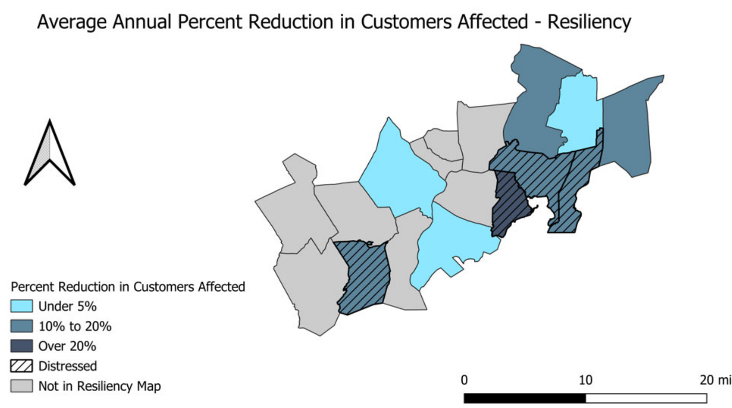


Figure 7. Reduction in Customers Affected by Outages Post Resilience Plan

Conclusions

As EDCs work to maintain and improve aging distribution systems, growing capacity needs, and increasingly variable weather conditions, transparent and rigorous evaluations ensure investments remain prudent and aligned with customer value. Defining a taxonomy of capital investments and the role they play in system resilience and reliability will allow for apples-to-apples comparison in future rate cases and a standard set of evaluation methods for assessing each program. While available methods and data do not provide perfect causation between programs and impacts, increased transparency benefits customers and allows regulators to assess proposed expenses.

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