BUSINESS PROCESS AUDIT

OF

EVERSOURCE

&

Public Service Company of New Hampshire

DISTRIBUTION CAPITAL PROJECTS

JULY

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FOR

THE NEW HAMPSHIRE

DEPARTMENT OF ENERGY

DIVISION OF REGULATORY SUPPORT

ELECTRIC DIVISION

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Executive Summary

The business process audit of Eversource's PSNH distribution capital project (CapEx) processes was procured by the New Hampshire Department of Energy's Division of Regulatory Support - Electric Division (Division), pursuant to the terms of a rate case Settlement Agreement approved by the New Hampshire Public Utilities Commission (PUC or Commission) in Docket No. DE 19-057, Order No. 26,433 dated December 15, 2020.

RCG understands that the genesis of this action involved communication concerns expressed by the Division covering PSNH's approach to project planning and management and the submittal of detailed Capital Projects information in the rate case.

As part of the recent PSNH rate case in Docket DE 19-057, the Division requested documentation for all distribution capital projects and associated estimates. PSNH delivered to the Division the requested information but did not provide complete and clear definitions for the multiple individual project estimates.

In this business process audit, RCG witnessed some communication issues with PSNH. RCG experienced communication issues resulting from PSNH responses to RCG data requests (DRs) including data provided in a format different from what was requested. Based on our process audit experience, RCG recognizes some DRs can take up to a month to prepare but taking three or more months is beyond the norm. Eversource did notify RCG when response times were expected to exceed the agreed upon response time.

DRs are designed to obtain and facilitate the review of standard information that a well-managed utility will use in its ordinary course of business. Specifically, the policies, processes, and procedures should be in place to create the information for successfully managing CapEx projects and tracking them for accounting, engineering, and regulatory purposes. The quality of internal or external communications is often indicative of systemic management control issues that are not part of a typical business process review and will require further efforts on the part of Eversource (see the discussion below).

As part of this audit assignment, RCG undertook an extensive interview process of PSNH and Eversource management personnel and we can report that PSNH arranged interviews consistent with RCG's expectations and appeared to be forthcoming in answering all questions.

A utility's capital planning process is expected to answer the following high-level question: "How much distribution system reinforcement is essential to provide the expected reliability and system resilience?" This question seems straightforward but is incredibly complex, with many variables impacting the final answer.

PSNH is part of a tri-state operation (New Hampshire, Massachusetts, and Connecticut) with different circuit configurations and voltages in each state. PSNH's distribution system is reasonably complex with three primary voltages (34.5kV, 12kV, and 4kV). Notably, some of the critical distribution equipment is older and, in some cases, potentially near the end of its life.

RCG reviewed Eversource/PSNH's functions that impacted the CapEx project process, including accounting and management policies and processes. In addition, RCG conducted a review of engineering policies and practices applicable to load forecasting, system planning, study methods, engineering tools, decision processes, and standards. The results are documented as they apply to core management and engineering functions: organization, engineering project control processes, energy forecasting, system planning criteria, system planning studies, reliability analysis, and the impact of distributed energy resources (DER). In RCG's opinion, these engineering functions, including their attendant processes, are well designed, but their execution, in some cases, was found to need improvement. This conclusion also applies to the policies and processes used to track individual projects.

RCG identified recommendations for the most significant improvement opportunities:

- ***Communications*** – The most significant issue is written and verbal communications, and consistent application of certain terms used by Eversource/PSNH to describe documents and processes. RCG believes Eversource generally understands the terminology, but outside entities may not. For example, some of the terms and definitions used by PSNH, which appear to have common usage, are used, and interpreted differently by other Eversource functional areas, for example "Supplemental" for an additional funding request or "Total" in a Projects' Excel spreadsheet. Communication issues also exist in the CapEx engineering processes, and in the language used in responses to data requests. Also, delays in providing requested information in data requests is a related issue; and
- ***Project management oversight*** – certain project plans as originally designed, were not effective during construction, as design flaws were discovered during troubleshooting and quality control phases of construction and rose to the attention of the Division during the rate case.

Another area reviewed by RCG involved "Third-Party Claims" costs associated with capital projects resulting from third-party damage to the distribution system. PSNH has no control over when third-party damages occur, which puts PSNH in a reactive situation.

While PSNH has formal Third-Party Claims collection policies and processes in place, the pace of collection is partially out of PSNH's control due to the state's lack of a mandatory auto insurance requirement and the inability of entities to promptly repay the repair costs. Third-Party Claims are included in this Business Process Audit because they represent a component of capital project total annual costs, and this issue was specifically highlighted for review by the Division.

RCG's review of the CapEx processes resulted in recommendations designed to improve communications and various processes to improve the overall flow of information within PSNH and for external stakeholders:

Capital Project Processing, Documentation, and Oversight

R.1 RCG recommends the Company retain and document higher cost and/or infeasible alternatives that were considered that could be provided to third parties during the regulatory process to aid in explaining the Company's decisions.

R.2 Ensure that all three Eversource oversight functions Internal Audit, Enterprise Risk Management, and Capital Budgeting annually review an appropriate sample of capital projects over $250,000.

R.3 Introduce formal peer reviews into the overall CapEx project development early in the process to support enhanced decisions and training for design engineers.

R.4 Enforce proper use of the term *Supplemental* consistent with APS-1 throughout the entire CapEx project process, including engineering.

R.5 Develop easy-to-understand examples illustrating the before-and-after impact of DSPG 2020 system planning criteria changes on system performance (reliability and resiliency) for all PSNH customer classes (residential, commercial, and industrial). The examples also need to clearly illustrate how superseded standards ED-3002 and SYSPLAN-010 will be used in conjunction with DSPG 2020.

R.6 Develop a formal process to communicate the latest industry activities, including lessons-learned and technology advancements, between departments and potential external parties (other utilities and suppliers).

R.7 Include person hours on all planned project work orders to support crew performance management.

R.8 Develop and test (as a joint effort between System Planning and Distribution Engineering) detailed Synergi feeder models, taking full advantage of System Planning's familiarity with Synergi to facilitate the process.

R.9 Perform an in-depth/rigorous analysis of the data-checking and conversion process for new software platforms (e.g., DistriView to Synergi data sets) independent of the Grid Mod group's conversion verification process to ensure that data continuity and integrity are maintained throughout.

R.10 Develop detailed documentation to maintain data integrity as data conversions are made from one software platform to another, e.g., DistriView to Synergi, Storms to Maximo. This is especially true for Synergi, where individual phase models for distribution circuits are being developed, i.e., converting from 3-phase balanced distribution line models to 1-phase unbalanced distribution line models.

R.11 Investigate the potential benefits of retro-filling power transformers with the latest technology insulating fluids, e.g., extending transformer life (without compromising reliability) and deferring capital investments. Include guidelines for identifying candidate transformers.

R.12 More clearly explain and illustrate with examples why the best overall solution alternatives are not always the least-cost solution alternatives. It is not sufficient to simply state that all criteria violations have been resolved. In addition, consistently document all alternatives considered in the formal project paperwork. Include a formal statement on NWA solution considerations (even if the statement says NWA solutions were not applicable) and reasons why.

R.13 Compare how the traditional solution alternatives are developed and priced against how NWA solution alternatives are developed and priced. Identify areas that disadvantage NWA solutions, e.g., how projected O&M costs are treated. Document key drivers that contribute to the cost differences between traditional and NWA solutions.

R.14 Develop and conduct in-house training programs for New Hampshire DER hosting map development engineers. Lessons learned from Eversource CT, and MA should be integral parts of this training.

R.15 Continue to investigate Conservation Voltage Reduction (CVR) potential energy/demand savings for PSNH, given the relatively high portion of residential system load --- 44% kWh residential sales: 50% kW residential peak demand.

R.16 Conduct a protection and coordination study in conjunction with System Planning at the distribution circuit level to better understand and anticipate how 2-way power flows can be safely accommodated.

R.17 Take more aggressive actions to correct chronic problem feeders by implementing one or more of the following:

- Reduce COSAIDI targets or other reliability targets to encourage more aggressive distribution automation and sectionalizing schemes; and
- Find locations where alternate feeds can be feasibly constructed for long radial circuits, i.e., create circuit loops, not just segmented customer groups; and
- Apply localized NWA solution options, where suitable, when looping feeders is not a feasible alternative and the solution exceeds the NWA threshold. Subsequent revisions to the NWA Framework may be required.

Third-party Claims Processing

R.18 PSNH should develop a formal method to track the status of third-party claims in process but not yet completed at the operating center level.

R.19 PSNH should create an accurate job description for the Administrator position that reflects the importance of the third-party claim's preparation process.

R.20 PSNH should revise the third-party claims process to have the Claims group review incidents where no responsible party is identified or when the operating center management has closed an incident without generating a claim.

R.21 PSNH should develop a flowchart and process narrative to define and illustrate the entire third-party claim process in one document.

R.22 PSNH should correct the software which improperly allocates reimbursements to Account 107 instead of Account 108.

Data Request Processing

R.23 If PSNH cannot complete a response to a data request and transmit the data response within ten business days, an estimated completion date should be formally transmitted by the tenth business day.

R.24 In its data responses, PSNH should highlight its ongoing and planned responses to issues and the impact of third parties' actions, rather than embedding the issue within the data.

R.25 To facilitate and clarify data requests and responses, PSNH and DOE should consider adding technical conferences before and after data requests are requested and responded to.

Communications Recommendations

Of the 25 recommendations developed by RCG, 10 recommendations focus in some manner on communications (R1, R4, R5, R6, R12, R14, R21, R23, R24, and R25). While each of these recommendations can be implemented on their own, Eversource should consider taking steps to improve its communications with external parties. These steps might include:

Eversource should convene, before the filing of Eversource's next rate case, a joint working group to understand external parties' needs and the impact of the present data transfer process on those external parties.

Eversource should develop a standard project documentation package that addresses the needs of all major parties in a rate case. One aspect would be to demonstrate the breadth of alternatives that were considered (including NWA) and why the lowest cost alternative may not have been adopted.

Eversource should ensure the terminology used in major documents such as APS-1 is sufficiently defined at a level that all parties (internal and external) consistently understand.

Eversource should host a technical session for external parties to illustrate the impact of the Distribution System Planning Guide 2020. This session would be focused on a non-engineering perspective using easy to understand terminology.

Eversource should invite external parties to regularly scheduled sessions to communicate the latest industry activities, including lessons-learned and technology advancements.

Implementation of these recommended actions will be challenging for Eversource and external parties and will require commitment from all parties to make the necessary structural and attitude changes.

Introduction

This process review of the Eversource, and its subsidiary Public Service of New Hampshire (PSNH), distribution capital project (CapEx) processes was procured by the New Hampshire Department of Energy's Department of Regulatory Support Division, Electric Division (Division) pursuant to the terms of the Settlement Agreement approved by the PUC in Docket DE 19-057. In accordance with Appendix 2 of the rate case Settlement Agreement in Docket No. DE 19-057, the following scope was adopted by RCG as the primary objective of the business process audit:

1. Review and assessment of the Company's capital planning, budgeting, approval, and management oversight, including:

   a. Company's budgeting and approval process for capital expenditures.
   b. Company's information systems used in work planning, tracking, and accounting.
   c. Initial project design and development of budgets, cost estimates, revised budgets and budget variances.
   d. Internal accounting for capital projects and administrative support.
   e. Decision making by project managers involving design changes, engagement and hiring of outside contractors and the Company's oversight of contractors.
   f. Decision making by project managers in addressing and controlling project costs including factors that necessitate the involvement of upper management.
   g. Reviews by upper management of project costs and cost overruns and the application of cost controls.
   h. Compliance of the above-listed items with good utility practices.

2. Review and evaluation of capital project documentation, including:

   a. Compliance with documentation policies and filing requirements.
   b. Initial project assessment and analysis in the PAF including consideration of known and foreseeable costs and risks.
   c. Use of Supplement Requests, including root cause analysis and lessons learned.
   d. Source documentation and supporting documentation.
   e. Recommendations for improving and enhancing the above documentation process.

3. Selective Project Review: The consultant will select a sample of capital projects for 2020 and 2021 to be included as a part of its examination and testing involving the above listed processes.

Based upon discussions with the Division at the beginning of the engagement, it is RCG's understanding that the genesis of this portion of the settlement was the result of the Division's review of PSNH's project planning and management processes and the unintentional failure of parties to communicate clearly.

RCG's investigative process cannot give specific weight or confirmation to actions or outcomes that occurred during the rate case, as the conduct of that case was not within the scope of this business process audit.

The Division also asked RCG to review PSNH's wood pole replacement practices including the application of steel poles on the distribution system, the rebuilding of distribution lines with 34kv hardware, and distribution substation maintenance and upgrading practices. These topics are addressed within the body of the report.

The following is RCG's audit philosophy and Covid response as expressed in our proposal for this review:

- Develop an assessment through a positive process that captures the perspectives and needs of all interested parties.
- Deliver a final report that provides a clear, independent, and objective evaluation of Company processes.
- Perform this audit in a COVID-19-safe manner as agreed to with NHPUC Staff. While all RCG team members are fully vaccinated, we also expect judicious video conferencing to help manage expenses.

RCG's consistent ability to meet the commitments of its audit schedules and produce effective results relies on the following approach/steps.

- Develop a formal work plan with clearly defined deliverables.
- Use experienced professionals who possess the combination of professional maturity, specific functional utility knowledge and audit work experience.
- Use both quantitative/qualitative data and information obtained through a structured data request process to evaluate the actual performance of the capital process.
- Develop conclusions consistent with generally accepted auditing standards which require thorough documentation of stated *facts* that support the findings/conclusions. Facts will include direct statements from PSNH/EE personnel, policy and procedures, physical observations, and other relevant data.
- Understand how RCG conclusions reached in one audit area may impact other areas. Determine how overall performance is improved through a clearer understanding of these connections and interactions.

- Use a tracking and retrieval system for work papers in a manner that supports documentation of the findings. On several assignments, the utility has had a format tracking tool that RCG will use to facilitate the smooth transfer of data and information.
- Use an editor to ensure draft and final reports are clear and consistent.
- Assure NHPUC Staff concerns are addressed.

RCG used a five-stage process that includes planning and orientation, fact-finding and analysis, conclusion and report construction, recommendation development and final report creation.

RCG brought together several disciplines to fully understand the situation, identify the root causes of identified issues, and provide an overall objective opinion of PSNH's actions relative to the state of their distribution system. Each RCG team member has over 40 years of utility or power engineering and operations experience. RCG has previously participated in other capital project development reviews and has captured what it believes to be the leading practices in this process area.

This process review of PSNH capital projects looked objectively at those engineering and management processes associated with identifying, planning, and executing distribution capital projects. RCG took a deep look into PSNH's engineering function and practices surrounding capital projects.

RCG understands that there must be a healthy dialog between PSNH and external parties to ensure PSNH customers are adequately represented and charged a fair price for the electric services they receive now and in the future. Further, PSNH must continue to provide the expected quality and continuity of service at a reasonable cost.

The specific elements this report will address include:

- Project management process
    - Project funding approval and oversight
- Project planning and engineering
    - Capital project identification
    - Technical capital project challenges
    - Capital project execution
    - Project closeout
- Third-party damage to capital equipment and the approach to managing the treatment of the associated capital spend

Project Management Processes

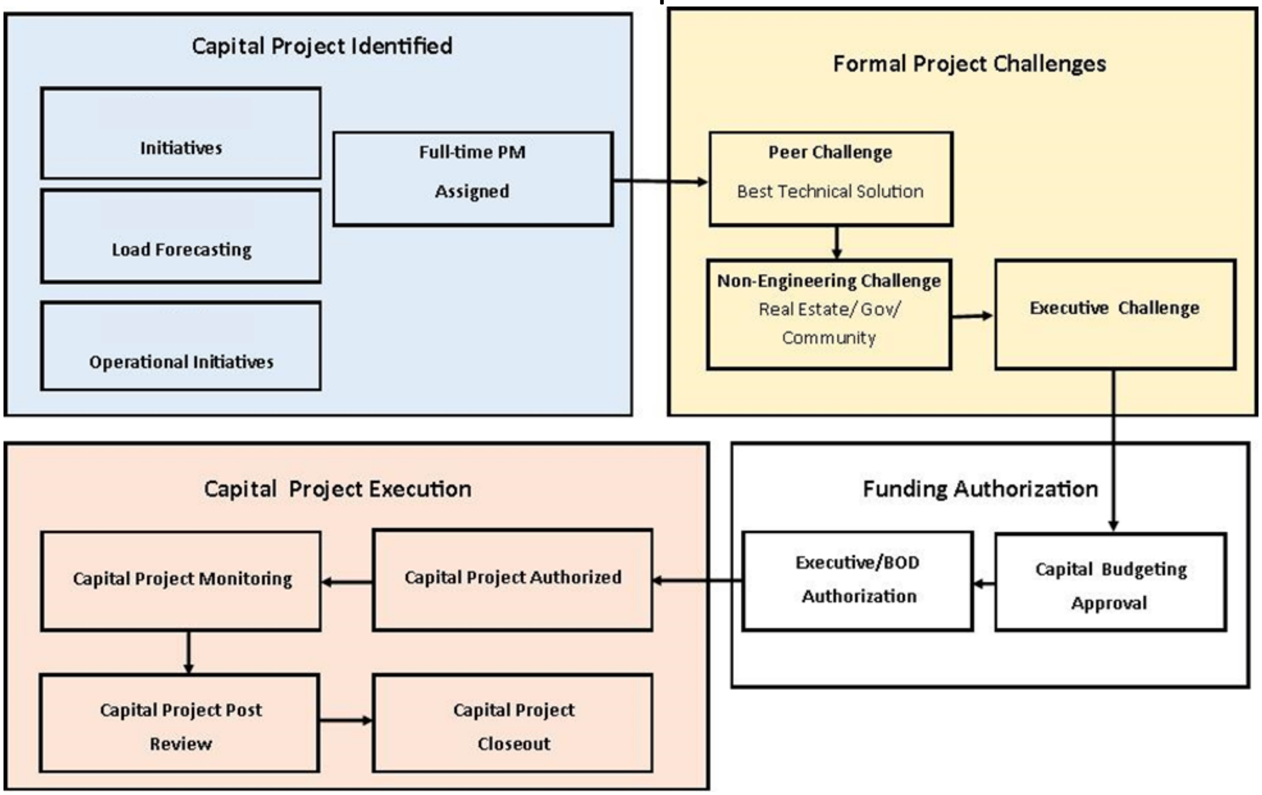
Before analyzing PSNH's CapEx program, RCG will introduce our model of the CapEx process developed over similar assignments, which led to the design of this CapEx process flow. The approach focuses on the capital dollar components of CapEx, but we will introduce several other critical processes which are part of any well-thought-out utility capital program.

2.1. RCG developed a Capital Projects process model, incorporating leading policies and practices for CapEx project identification, design, authorization, and oversight processes in the utility space.

This high-level CapEx process model represents the leading practices used in client companies. It reflects minor modifications to streamline the flows and not unduly tax the company personnel responsible for implementing the process. Exhibit 1, on the following page, shows RCG's general process flow for CapEx projects. Notably, the model addresses the approval process, not the detailed engineering process, since that can vary between utilities. As mentioned earlier, the engineering process reviewed in the coming chapters addresses another of the Division's questions. Further, the internal oversight functions are not included in the RCG CapEx process flow but are critical to ensuring all company policies and procedures are performing as designed.

This report will review the processes and actions shown in Exhibit 1 and include other tangential elements identified as critical to the process to clearly understand PSNH/Eversource's process approach to capital projects' life cycle and the state of the NH distribution system. RCG uses the term "Projects" in this document to refer to both stand-alone CapEx projects and programs. Programs are a catalog of similar distribution and substation projects routinely performed across PSNH's service territory over several years.

Exhibit 1 - RCG CapEx Model



The blue box, *Capital Project Identified*, shows the sources of Distribution CapEx projects. The first sub-box, Initiatives, indicates corporate policy and standards. Here Eversource sets the guidelines for how systems will be built and maintained, along with equipment specifications and typical designs. Distribution engineering also continually evaluates the system against the standards selected by the utility while ordering system enhancements to keep the system operating within PSNH's set parameters. The second sub-box, Load Forecasting, identifies the future growth patterns and the impact of customer conservation activities and third-party distributed generation. Forecasting looks at peak load (kW) and energy usage (kWh) requirements to determine when and where to expand the system's capacity. As noted in the Engineering chapter, several design and policy concerns were evaluated, along with deciding if PSNH/Eversource evaluated alternatives. It is important to note here that in New Hampshire, distribution companies do not own generation other than for emergency power situations. PSNH operational initiatives deal with unique distribution system situations which will impact system performance. The final sub-box is the assignment of a non-engineer project manager to shepherd the project from inception to project closeout, where the project is moved into the company's capital base. This individual is not responsible for engineering the project but reports progress to management and is responsible for explaining any anomalies or cost variations that might occur during the project. The project manager function provides checks and balances within the project structure with engineering and construction. This individual is the continuity link for the entire project.

The yellow box, *Formal Project Challenges*, is critical to ensure a project is well thought out and prepared for unexpected contingencies. Further, it helps define the best alternative solution for the final project. In this manner, the project team considers the impact on local reliability, including reliability around the specific location, e.g., other substations and feeders, identification of potential impediments to the construction, and alternative cost comparisons. This also offers an opportunity for peer design engineers to challenge the selection of the design engineering team, which also supports learning opportunities while providing valuable insights into the project from various positions. Next, it allows non-engineering personnel to review the project from community, municipal, and state requirements that could impact the design and execution choices. Finally, the executive challenge looks at the project from a needs aspect and consistency with corporate policy.

The white box, *Funding Authorization* ranks the project against other projects competing for the same finite funding. If selected, the budget is approved, and the project moves forward. The critical point is that the project may receive capital funding over several years, or annual CapEx cycles, until completed.

The tan box, *Capital Project Execution*, specifies where the fully engineered project is built, inspected, put into service, and officially closed out from an accounting perspective. The entire process can take several years to complete for substation projects and significantly less time for some distribution line projects.

2.2. Eversource recently recognized the issues in the capital project process and made changes, however, alternative designs were deleted once management selects the most appropriate design.

It is RCG's understanding that PSNH/Eversource recognized issues in their capital project budget and estimating processes approximately four years ago and began making substantive changes in the 2017-2018 timeframe. However, an issue discovered by RCG remained unaddressed which PSNH is now addressing because of RCG's early investigation efforts during this audit assignment. RCG noted after observing a PSNH project review session, that once a decision was reached on which alternative project design would move forward, the remaining alternatives appeared to be deleted. RCG also noted that there is a certain degree of informality imbedded in PSNH's communication involving language and detail that non-employees may find difficult to understand. This issue involves spoken and written formats, including a lack of consistent use of definitions and the prompt delivery of essential information as requested in regulatory proceedings. In addition, RCG found that certain project plans, as originally designed, were not effective, as design flaws were discovered during the troubleshooting and quality control phases of construction.

Eversource and PSNH appear to have the appropriate engineering and operational policies, procedures, and processes for managing and maintaining a reliable distribution network in New Hampshire. Still, the written and verbal communications encompassing these efforts are less than what RCG would expect from a company of the size and stature of PSNH/Eversource. While PSNH/Eversource personnel and the management team understand most of what is being said and written inside PSNH, external communications with parties outside the internal process, such as Division Staff, are oftentimes confusing for those parties. This review uncovered several communication issues, which confused our team of utility experts at first glance. These issues will be covered in the appropriate sections of the report and should lead the reader to the same set of conclusions RCG reached during the process review. Specifically, RCG found both written and verbal statements that, on their surface, could be interpreted differently than initially intended. Further, RCG, in performing this process review, identified several issues, which, if not explored more deeply, could lead non-PSNH/Eversource personnel in different directions if the appropriate "next" questions are not asked to achieve clarity. Specifically, RCG found:

- The length of time to respond to some of RCG's data requests exceeded what RCG has experienced in prior process audit reviews. The Division indicated that it has experienced this same issue. This outcome led RCG to conclude that the customarily expected information is not routinely maintained and archived in some instances.
- Standard PSNH terms are not consistently applied across the processes or results. One example was using the PSNH/Eversource word "Supplemental," which was used on several Company spreadsheets as a "total" inconsistent with its formal definition.
- Some information that should be maintained is either discarded or not documented once a design is selected. One example witnessed by RCG is the discarding of alternative solutions once there is a selected project approach. RCG does not infer anything unethical about eliminating this information but assumes it is likely attributable to an effort by PSNH to merely simplify the remaining documentation. Additionally, this action fails to recognize the future need for this solution information by other outside parties such as the Division.

These issues will be reviewed in the appropriate sections of the RCG report.

2.3. Eversource and PSNH have done a reasonable job of estimating projects.

Before moving into the formal review of the processes, RCG will present the results of our study of completed project' estimates vs. actuals for 2012-2020.

Exhibit 2 – Project Estimate to Actuals

Year	Percent of Projects Under Estimated	Under Estimated >20%	Total Projects	Over Estimated >20%	Percent of Projects Over Estimated
2012	100%	1	1	0	0%
2013	33%	1	3	0	0%
2014	56%	5	9	1	11%
2015	52%	15	29	4	14%
2016	57%	13	23	4	17%
2017	29%	7	24	2	8%
2018	21%	5	24	4	17%
2019	30%	7	23	0	0%
2020	22%	5	23	4	17%

Exhibit 2 shows a reasonably balanced comparison of under- to over-estimated project costs by year. Except for 2015 and 2016, PSNH made a reasonable effort of estimating projects when compared to actual project cost. This result is essential for the following general reasons:

- Underestimating project costs could produce too many projects not being completed within the annual CapEx budget cycle due to a lack of funding. Consistent underestimating could indicate challenging estimating practices or an inadequate effort to assess project risk factors.
- Overestimating project costs can produce an annual plan with fewer projects due to funding limits. If most projects are overestimated, RCG would be concerned about the potential to pad projects to meet estimating goals. This is not the case here as there are few projects by percentage in this category.

From Exhibit 2, PSNH has more difficulty under-estimating CapEx for projects than overestimating. Although in the last four years, PSNH appears to be doing a better job of estimating. Overestimating seems to be less of an issue for PSNH. Recent efforts appear reasonable when considering the pandemic and its negative impact on the supply chain.

The industry standard is to accept projects completed based on the budget if they are within plus or minus ten percent, which is PSNH's target. RCG has moved the target to twenty percent (20%) to account for recent supply chain issues.

Exhibit 2 indicates a reasonable balance between the over/underestimating except for two years.

Recommendations

R.1 RCG recommends the Company retain and document higher cost and/or infeasible alternatives that were considered that could be provided to third parties during the regulatory process to aid in explaining the Company's decisions.

Internal Management Oversight

3.1. Three separate functions provide independent internal oversight.

The three different functions providing independent internal oversight essential to managing corporate processes are Internal Auditing, Enterprise Risk Management, and Capital Budgeting; however, at PSNH, the first two are conspicuously limited from the PSNH Distribution Capital Line Projects due to Company threshold guidelines.

The internal and independent oversight of all PSNH/Eversource-approved CapEx processes is essential to monitor the integrity of all company processes. Having an internal oversight function of the distribution CapEx process (separate and apart from the engineering/operations function) allows for independent validation of the procedures and policies application. This instills confidence in the processes and attendant outcomes. Within Eversource, internal but independent reviews are performed for substation projects via three separate functions:

- *Internal Auditing (IA)* – Looks at the Company's process controls and in specific projects to ensure compliance with Eversource policies and procedures or where management has concerns over project outcomes for projects. Audit of specific projects generally consist of large dollar/complex risk projects generally over $50,000,000. From an accounting perspective, the oversight of the capital approvals and management is a critical, required set of activities.
- *Enterprise Risk Management (ERM)* – ERM participates during the early development of all substation projects to ensure that all reasonable potential risks are identified. It also impacts the final *Pre-Constructability Estimate and schedule.* Participation is limited to projects greater than $25,000,000.[1]
- *Capital Budgeting* – begins with project development and design. The PowerPlan tool tracks the project's initial conceptual engineering estimate through the development of additional engineering "building block" estimates. Project post-completion responsibility is to compare the total actual engineering and construction costs against the authorized final *Pre-Constructability Estimate*. It is the final estimate in a series of evolving estimates that reflect the project's engineering development stages. Eversource engineering prefers this approach to tracking engineering CapEx distribution projects so that all engineering parties and management can understand the evolution of the project's final *Pre-Constructability Estimate.* The *Pre-Constructability Estimate* once approved becomes the *Full Funding* amount for the specific project. The last and consequential *Pre-*

[1] Interview #35

Constructability Estimate is used in the Company's formal capital budgeting process to communicate between the parties as defined in the APS-01 process. The APS-01 is Eversource's project authorization policy. Until January 1, 2022, APS-01 required the estimators to use only direct labor and material costs, omitting the indirect costs associated with labor, supervision, and administration, when determining if a supplemental authorization request was necessary if actual (total) project costs were expected to exceed authorized (total) project cost estimates. This prior approach would generally guarantee that the final (total) project cost would be off by the value of the indirect adders, which could have been in excess of an acceptable threshold. This was changed as of the first day of 2022 and will lead to more projects being evaluated on whether a supplemental cost authorization form is needed when all actual costs are compared to all cost estimates to determine if they exceed the acceptable threshold.

3.2. Internal Auditing (IA) works with an annual audit target of fifty audits/reviews for their official annual auditing plan across Eversource businesses. This yearly plan's number of audits driven by IA staff size precludes IA from evaluating lower risk/value projects and therefore limits the number of New Hampshire business audits, including the New Hampshire distribution line function.[2]

The Institute of Internal Auditors defines internal auditing as "an independent, objective assurance and consulting activity designed to add value and improve an organization's operations." IA helps an organization accomplish its objectives by bringing a systematic, disciplined approach to evaluating and improving financial risk management, process controls, and governance processes.

RCG only evaluated IA's function concerning its ability to provide adequate independent oversight of the NH Eversource distribution capital processes. IA is tangential to the CapEx Process but critical to monitoring the process from a control perspective. RCG conducted two interviews on IA organizational structure and reporting lines, responsibilities, experience, training, audit planning and execution, post-audit follow-up, and best practices. We are not commenting on the function but only on its support of the PSNH Distribution CapEx projects.

IA is positioned correctly within Eversource to provide independent assessments of selective Eversource's processes and controls. It appears to be professionally staffed with individuals who meet the requirements of IA auditors. The audit planning process is

[2] Interview #10 and Interview #9

appropriately risk-based, and audits are identified and prioritized based on input from the organization.

Eversource's Internal Auditing has four sections[3]:

- The operational audit group performs process audits across:
    - Electric Distribution,
    - Gas,
    - Water, and
    - Transmission functions.
- Information technology audits, supported by contractors, and
- Sarbanes-Oxley compliance, and
- Environmental, Customer Care, and Corporate (CFO, HR, and General Counsel).

IA has a formal plan to conduct approximately fifty (50) audits annually[4] for the entire Eversource organization. Most annual audits are pre-planned as opposed to reactive audits. The Vice President of IA is proud that when his organization is compared to other Northeast utility's IA organizations, they are slightly smaller in staffing size but achieve a significant amount of work. The annual audits are conducted by a total staff of approximately twenty (20) people, including the four managers reporting to the Vice President of Internal Audit & Security. IA's staffing design makes it challenging to conduct additional audits across all business units within the Eversource family. According to IA, of the 50 planned audits conducted annually only, 18 to 20[5] are within Eversource operations that would include CapEx distribution projects, which would be across the entire Eversource family of operating companies.[6] The remaining 30 plus audits include IT, Environmental, Customer Experience, Corporate Services and CFO function.

IA uses a formal risk rating system that rates all key risks categories including financial, operational, external, technical, strategic, and historical. However, the dollar amount is only tied to the physical project's cost when considering auditing CapEx projects. It does not include the potential harm/risk to Eversource financials caused by the possible rate disallowances that might occur during a rate case due to an issue with a specific project.[7]

The IA formally tracks open audit recommendations made in previously conducted audits, demonstrating that follow-through exists in IA.

[3] Interview #9
[4] Interview #9
[5] Interview #9
[6] Interview #9
[7] Interview #10

The group monitors and compares itself to industry best practices. It participates in regional peer reviews[8] and adheres to the Institute of Internal Auditors Standards and the Code of Ethics.

3.3. Enterprise Risk Management (ERM) works within a minimum project/program spend limitation of twenty-five million dollars. There are not enough resources to cover all the projects and programs, so the focus is on the high dollar efforts which preclude PSNH line distribution capital projects. It will have the most significant impact in Exhibit 1's yellow Box, *Formal Project Challenges*, as this function will test the design team's risk assessment evaluation from several different directions.

ERM is critical to supporting RCG's CPPM, as it helps identify all potential project risks outside the project's design to protect project budgets and schedules. Eversource ERM generally does not review projects valued at less than twenty-five million dollars.[9] Specifically, in RCG's Exhibit 1, the early peer reviews involve other co-workers working in different disciplines, e.g., real estate, governmental and customer affairs, and others. Much of these are covered via ERM.

PSNH's "Regional Barns" or local operations centers, personnel appear to informally provide local knowledge of the design and unique conditions, reducing a portion of risk and allowing for additional project costs. But here, due to project size, there is no outside group evaluating the distribution design and its potential risks. It is important to note ERM has helped create lists of likely project risks based on past experiences, which are available to the designers and management.

This function will test the design's ability to withstand several risk areas, including government imposed issues, environmental and permitting, customer issues, regulatory requirements, and potential geological issues. These risks can add significant costs to the project while potentially impacting the construction schedule. In one example, RCG inspected a distribution line construction site that traversed wetlands and required a substantial level of environment mitigation using an extensive level of matting and a unique pole foundation design which increased the cost of the line installation significantly. Specifically, on this one project, PSNH had to pay for the installation, removal, and rental fees for the period the matting was installed in this marsh area. PSNH performed the necessary walk-down of the site, which allowed them to identify the wetlands, design changes, and incorporate the required additional expense into the

[8] Interview #10

[9] Interview #35

estimate. In the past, RCG has seen several utilities which allowed their engineers to design from their desks and this approach would have missed the need for matting. PSNH/Eversource supports engineers going to the field during the design efforts, a practice RCG supports.

RCG is always concerned, in these types of studies, that these risks can be used to cover poor estimating practices or to ensure that projects are not overestimated to prevent projects from coming in well over the estimates. Based on our review of the requested CapEx projects, this doesn't appear to be an issue. There are several overestimated projects which appear to be within acceptable parameters. In comparison, there were a much higher number of projects underestimated.

3.4. Capital Budgeting is correctly responsible for overseeing the capital budgeting for projects and adherence to Eversource's *APS-01* policy and process, in addition to managing Engineering's use of *PowerPlan*. The group monitors and oversees a capital project's estimating, funding, and spending processes. The group ensures procedures are followed from determining the specific project capital budget through total spending on projects, including reports on the accuracy of the approved constructability estimates. This group is responsible, along with project management, for monitoring and reporting on the project financials.

A critical element to understand is that from a financial/accounting perspective, both the *PowerPlan* and *APS-01* are managed under the capital budgeting function, which allows for an independent review of capital budgeting components of a project throughout its life. The process provides for monitoring project estimates and expenses regardless of where or when they occur. *APS-01* establishes the evaluation, decision-making, and approval process of all projects -- per this policy. More importantly, it defines how PSNH will define, manage, and perform quality control of CapEx projects.

> "*A project is defined as a commitment by Eversource of internal and/or* external *resources to accomplish an initiative that will have economic impact to the Company, its customer and/or is required by policy or regulatory standards. The overall policy objective is that projects should be evaluated and approved in accordance with the DOA prior to the commitment of company resources.*"[10]

[10] DR BPA-1-12, Att. B p3

Importantly, PSNH, like other utilities, provides initial funding dollars for the physical initial scoping and engineering of the project. This early *Conceptual Estimate* should *not* be used to compare with the project's as-built final cost as the initial *Conceptual Estimate* does not contain expenses associated with equipment, construction labor, property procurement, overheads, etc.

In concert with the capital budgeting process and *ASP-01*, but integral to the approval process, the PSNH/Eversource's formal *Delegation of Authority* (DoA) policy clearly defines the management approval required for the total project value. The higher the project value, the higher up the management chain for approval is required. Ultimately this can lead to the Board of Directors' approval requirement. DoA is an accepted standard industry policy and practice allowing the appropriate management levels to oversee project approvals actively. The CFO organization is the corporate sponsor for these two policies.

Supplementing APS-01 and the DoA are the following related policies and procedures: [11]

- *Capital Project Approval Process Job Aide,* (JA-AM-2001-A, Rev 5 6/1/2020)
- *Engineering Deliverables Administrative* Procedure (M7-EN-2000, Rev. 0, Eff. 7/1/2020)
- *Power Plan Procedures Manual and Users Guide*
- *Integrated Planning and Scheduling Process Playbook (IP&S Playbook*) (Revision: 0.1, November 30, 2017)

The *Capital Project Approval Process Job Aid* provides instructions and guidance on the process. It identifies the organizations responsible for the capital program project review and approval process following the *APS-01* policy. The *Business and Quality Assurance, Transmission Organization*, is responsible for administering the *Job Aid*. RCG found using a *Job Aid* to provide detailed instructions for creating a project is consistent with industry practices.

Engineering Deliverables Administrative Procedure[12] provides the detailed responsibilities and specific actions engineering personnel (PSNH/Eversource and contractors) must follow in the capital project development and approval process. Specifically, this procedure offers guidance for each design phase of a project. Additionally, it provides a complete list of deliverables to be considered by the engineer in developing the design packages for all transmission and substation projects. Most

[11] DR BPA-1-012

[12] DR BPA-5-007

importantly, it allows the project sponsor to validate the design against the need statement and the accuracy of the project estimates and budgets.

RCG found this procedure to be consistent with industry practices. However, RCG found many instances where the design packages did not include and/or retain sufficient documentation of the alternative solutions that had been considered. Additionally, one substation project designed by a contract engineering firm did not receive a good review from the project sponsor. It resulted in the need for considerable rework and additional capital costs. See specific examples in the Engineering Section of the report.

Power Plan Procedures Manual and Users Guide[13] provides detailed instructions on using the *Power Plan* software in the capital budget, project development, and approval process. Included are specific instructions for developing the project funding request and creating the work order. These recently updated procedures clarified the requirements for the attachment of project documents including the *PAF*s. RCG found these procedures consistent with utility industry practices and supports the documentation filing practice improvement.

Integrated Planning and Scheduling Process Playbook (IP&S Playbook) [14] provides detailed steps for the following:

- An annual work plan,
- The weekly "work order plan", and
- The schedule for field and station operations, electric service, and response specialists.

The annual work plan process covers work identification, budget and resource balancing, and the development of project scope details. The work order planning process lists the prerequisites required for a work order to move into the scheduling window. Once in the scheduling window, the weekly and daily scheduling is developed. This planning results in a weekly work plan targeting 80% of the available hours, with the remaining hours focused on emergency and emergent work. However, the associated work orders for each project do not include targeted work hours to enable supervision to assess individual crew performance.

RCG found the processes and practices described in Eversource's IP&S playbook to be, with the exception noted above, consistent with utility industry practices and found it implemented consistently across PSNH.

[13] DR BPA-11-012 Att. A and b
[14] DR BPA-12-016

The above policies and procedures are combined into PSNH's annual capital budget and project development processes.[15] The PSNH Capital Budget starts with reviewing and updating the *Long-Range Plan* and associated five-year budget forecast early each year. The capital budget development for the upcoming year follows later (in the year) with the annual executive challenge session. At this session, Distribution Line Projects are discussed, including:

- Peak load and reliability-driven projects,
- Line upgrade projects associated with meeting distribution planning criteria, and
- Any distribution ROW rebuild projects, where the scope of the work is a project rather than the $100K limited ROW annual program.

Further, projects in process, including pole-top distribution automation, oil filled circuit breaker replacements, animal protection, obsolete relay replacements, and annual projects such as transformer purchases, new services, and municipal driven work will require budget funding forecasts. Collecting all projects with forecasted estimates leads to a preliminary annual budget.

PSNH leadership then reviews the preliminary annual budget. If approved, it becomes the basis of the capital plan and is presented to Eversource Executive Leadership and the Board of Trustees for approval. Adjustments to the following year's capital budget are based on actual project costs, schedule adjustments, and emergent system needs. The decision on whether to fund a project currently unidentified in the capital budget is made monthly at the Capital Budget Review Meeting, chaired by the President of NH Electric Operations.

Since most distribution line project development takes place before the Challenge Session (described above,) preliminary design work is already underway (provided budget approval has been received.) However, the specific line projects cannot move forward to construction without first being approved by the NH Project Approval Committee (NH PAC). At this point, the *Project Approval Form* (PAF) is submitted to the NH PAC for review once the design is complete. The decision to use internal or external resources is then selected, ensuring the best estimate is available at the time of the NH PAC review. Distribution line projects are then prepared and presented by the organization that initiated the project.

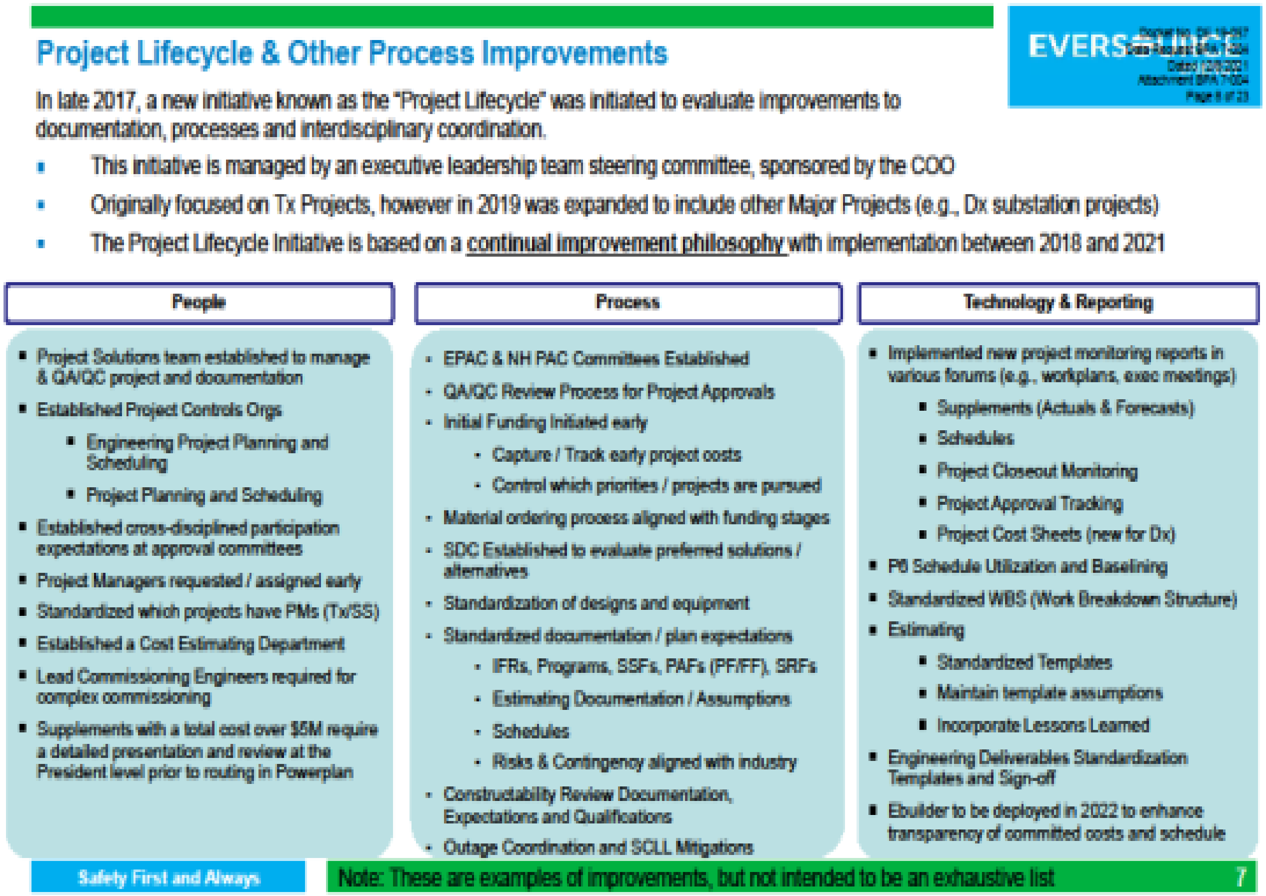
[15] DR BPA-8-029

Similarly, substation projects are developed based on the priorities outlined in the annual capital budget and presented to the *Eversource Project Approval Committee* (EPAC). Since the duration of substation projects is typically longer and more complex than distribution line projects, initial funding and partial funding are requested regularly to support detailed design deliverables. Full funding authorization, approved by EPAC, is required before a substation project can move to construction. Distribution substation projects are also prepared and presented by the initiating organization.

RCG found PSNH/Eversource's capital budget and project development process consistent with industry practices. However, as previously discussed, there are limited opportunities for proposed distribution line projects to undergo peer-to-peer challenges to design alternatives.

PSNH/Eversource has updated its capital budget and project development policies and procedures during this BPA to reflect Eversource's improvements in cost estimate documentation, alternative solution development, and document retention. A number of these improvements were a direct result of interview discussions. The following exhibit reflects improvements Eversource has made in its capital business process:

Exhibit 3 - Life Cycle and Improvements[16]



In 2021 changes were implemented regarding the Distribution Line Capital Project Process. The "*pre-construction final estimate*" is now the estimate that the NH PAC will approve, and the construction organization will be held accountable for delivering the project's final cost.[17]

However, two components of the budgeting process contribute to the confusion experienced by outside parties, in particular the Division, involving estimates and additional costs added to the original estimate.

- The term *Supplemental* funding is defined in *APS-1* but has been misapplied. "*Should additional, unexpected costs to the project materialize, **the formal process described as the "Supplemental" attaches those costs to the original***

[16] DR BPA-7-004 Att. p9

[17] DR BPA-12-014

authorized pre-constructability Estimate."[18] RCG understands that *these "Supplementals"* go through a rigorous review by the engineering organization for substation projects. For line distribution projects outside the substation fence, any supplementals are approved by the Director of New Hampshire Distribution Engineering after a thorough vetting. During RCG's review of the CapEx projects data request (DR) form, the RCG team found that the term *"supplemental"* could become confused with total project cost (combining the original authorized amount with the additional supplemental dollars and called the *supplemental*.) This set of conditions could create a point of confusion for anyone not familiar with the form and the process.

- In one project, PSNH pointed out that the extra cost was due to an unforeseen change in the contractor selected and included in *the Pre-Constructability Estimate* because the work had not yet started. We agreed, subject to Eversource's accounting department approving the policy definition until the metaphorical "shovel hits the ground." These unforeseen cost changes would not be supplementals for this report but included in the *Pre-Constructability Estimate*. In Eversource's 3rd Step Adjustment filing, the term "*supplemental*" was used in the supporting spreadsheets as the heading title for the total expenditure column, including any *supplemental* funding. This approach has continued to contribute to confusion on what data PSNH is presenting and does not contribute to clear communication of the overall PSNH position.

PowerPlan may indirectly create another point of confusion for outsiders reviewing the CapEx project estimates from two aspects, the number of estimates produced during the project's development and the use of the term "*supplemental*." This issue is reviewed further in the Engineering section of this report. During a review of one of RCG's requested CapEx projects, one project led to significant discussion between RCG and several members from distribution operations. The discussion focused on when a *supplemental* is genuinely a part of the initial *Pre-Constructability Estimate* and, therefore, not treated as an additional unplanned expense. The project was not in construction, but the estimate increased due to a change in contractors. The Company argued that since the winning vendor had not been identified during the final efforts of the *Pre-Constructability Estimate*, the additional cost resulting from a change in construction contractor should not be held against the project estimator as an oversight cost. Without formal input from the Eversource accounting department, RCG would consider any additional cost as part of the *Pre-Constructability Estimate* for this process review.

[18] APS-1

The first two independent oversight reviews appear to work well for those substation projects due to the high dollar value of the projects exceeding the minimum threshold. The distribution line projects are typically below this predefined value and not subject to these two oversight review processes. The reasoning behind these limits is reviewed below, along with a short definition of each function.

3.5. Many current substation capital projects under construction may not have fully benefited from the post-2018 CapEx process and policy changes.

Substation projects can span years between need identification and completion due to completing critical sub-project elements, including detailed engineering, acquiring properties, obtaining licenses and permits, conducting environmental assessments, approvals, and significant equipment production lead times. Therefore, many existing substation projects could have started five or more years ago, preceding the current policy and process changes surrounding CapEx projects.

Substation projects covering multiple years have added to the complexity of RCG's evaluation of these large capital projects against our CPPM. Eversource CapEx projects' processes and policies were changed around 2018. However, several current projects under construction were designed before 2018, meaning they were designed and engineered under the previous policies and processes, which lacked the benefits of the new process elements and potentially impacted their accuracy. In addition, some system design standards have been modified, either by policy or upgraded distribution system standards. These concerns are discussed in the engineering chapter. All of this can cause explainable and acceptable variances. Further, some projects had significant issues resulting from not having the benefits of the new policies and procedures. Several of these will also be addressed in the Engineering chapter.

Recommendations

R.2 Ensure all three Eversource oversight functions Internal Audit, Enterprise Risk Management, and Capital Budgeting review an appropriate sample of capital projects over $250,000 annually.

R.3 Introduce formal peer reviews into the overall CapEx project development early in the process to support enhanced decisions and training for design engineers.

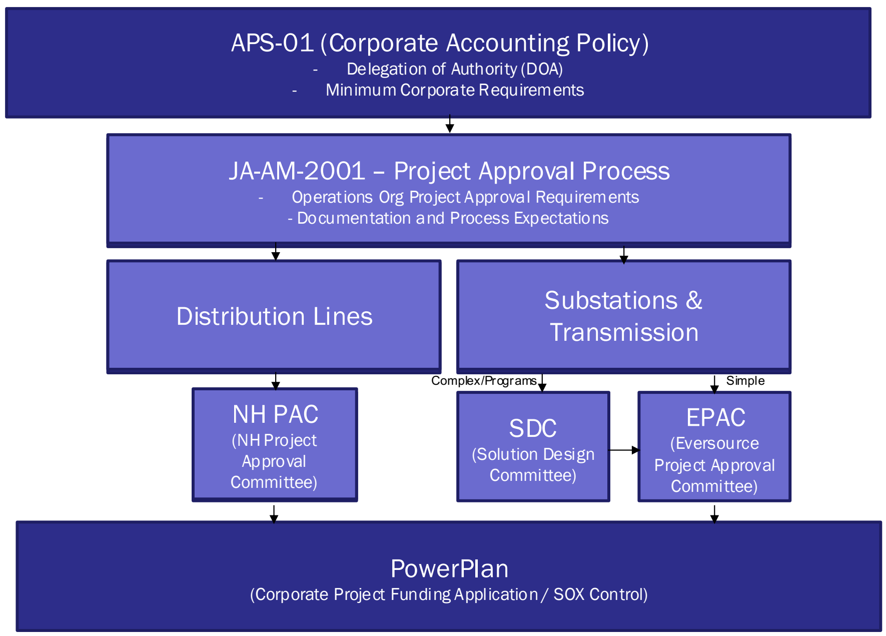
R.4 Enforce proper use of the term *Supplemental* consistent with APS-1 throughout the entire CapEx project process, including engineering.

Engineering Capital Project Approval Process

4.1. The capital project approval process is well designed, but its complexity varies with the project class. Further, formal initial peer reviews are not formally included.

Exhibit 4, provided to RCG during the Kickoff session, shows the hierarchy of the capital projects approval process and the two different process versions.

Exhibit 4 - High-Level CapEx Project Approval[19]



APS-01 is Eversource's formal and governing accounting policy and process. This document includes the traditional definition of the *Supplemental*. *Supplemental* is additional capital funds added to the original authorized CapEx project's budget, initially referred to as the *Pre-Constructability Estimate* by Engineering after their design process is finalized. *Pre-Constructability Estimate* is critical as it signals the end of the engineering phase and becomes the number used in the *Full Funding Request* approved at the *Eversource Project Approval Committee* (EPAC) or *New Hampshire Project Approval Committee* (NHPAC). Any *Supplemental* applied to either substation or distribution line projects are formally reviewed by the appropriate leadership team.

Importantly, all substation design engineering work is managed through Eversource's Substation Engineering function regardless of whether it is for transmission

19 Capital Project Approval Process, JA-AM-2001-A, Rev 5 Job Aid

or distribution. Further, it encompasses all Eversource distribution companies regardless of distribution voltage variations. This design centralization is expected in the electric utility industry. It promotes consistent design results for specific substation types, minimizing the potential for errors while promoting design consistency across PSNH by primary voltage combinations. Further, it allows operations to better use their resources and engineering personnel across the PSNH system. The voltages may differ, but the protection and switching procedures can be the same, reducing the potential for field-induced operating errors.

RCG discovered one flaw in the CapEx estimating process; it required the project estimators or managers to consider only the direct costs associated with the project when determining whether a supplemental authorization (additional funding request) is required. RCG identified this early in our discovery effort. Since then, Eversource has changed the *APS-01* policy as of January 1, 2022, to require total cost (direct and indirect costs) be considered when determining whether an additional funding request is needed.[20]

The *JA-AM-2001 – Project Approval Process* takes the overall Distribution CapEx project approval to a more technical and granular level of actions and approvals during the needs assessment and engineering design. It is here where a critical distinction occurs between substation and distribution Line projects. As shown in Exhibit 4, the substation projects must first go through the *Solutions Design* Committee (SDC) and, with their approval, advance on to the EPAC, which must approve the CapEx for substation and transmission projects from across the Eversource family of companies. Both committees can return the project to the designers for additional design and requirement efforts. The SDC committee, which tends to be a technical review, will work with the designers before the SDC presentation to ensure that the required forms are correctly completed and that the selected design meets the PSNH's expectations.

4.2. The Distribution Substation Approval process is detailed and permits close tracking of the project's budget development through a series of evolving estimates in *PowerPlan* that reflect Engineering's efforts. But the process appears to lack sufficient formal peer-level reviews.

The process appears to lack sufficient formal peer-level reviews that allow alternate designs to be considered earlier in the process and function as a learning tool for engineers. In addition, it provides for the use of the term *Supplemental* before an authorized capital project is designated, potentially creating a point of confusion for

[20] DR BPA 12-015 and Interview #43

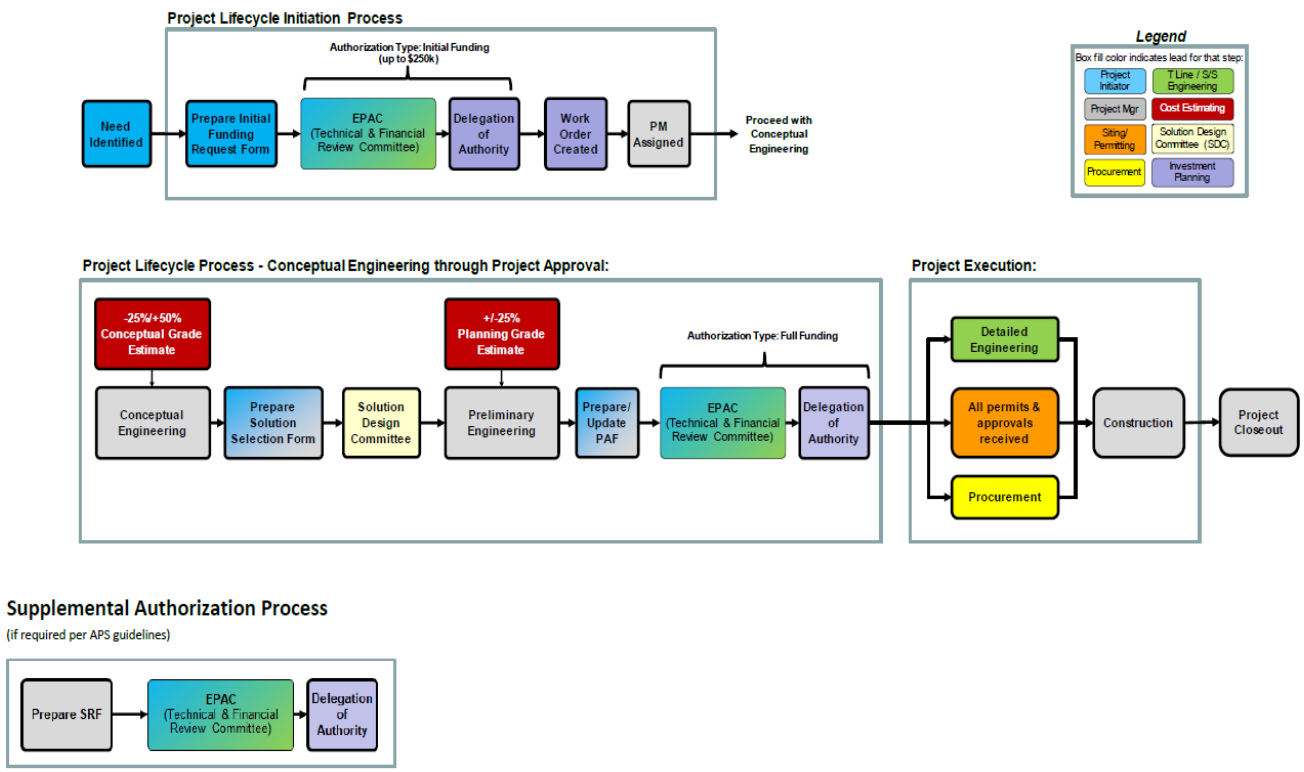
outside parties', in particular the Division, not having the benefit of the list of estimates' definitions, selects and reviews the wrong estimate for comparison with the project's final installed cost. This situation is the result of the Company not providing adequate definitions on each of the different estimates prepared.

Exhibit 5 shows Eversource's Substation Project Approval process, including the Supplemental Authorization process. An important distinction is that substation engineering is positioned in Eversource for all three states. The process is complex in its flow but appears to provide Eversource with most tools RCG deems appropriate and necessary for NH Substation-type projects. It does not, to our knowledge, have a rigorous formal peer review. The reviews are performed by management in the two large-format meetings conducted twice monthly and on the same day. The EPAC session involves many participants from across the Eversource family of companies and appears to be financially focused. Several members of the SDC meeting attend the EPAC session as well.

Exhibit 5 includes a subprocess for *Supplemental* increases during the engineering efforts. This use of *Supplemental* at this project stage is one of those communications-definitional issues raised earlier. According to *APS-1*, the use of *Supplemental* is reserved for projects having *Full Funding Authorization*. In other words, they have achieved the *Pre-Constructability Estimate* status and are authorized to proceed. This use is not the case for the engineering estimates that precede this part of the process.

Exhibit 5 - Substation Project Approval Process

Attachment D, Transmission and Substation Project Approval Process Flow Charts



Capital Project Approval Process - JA-AM-2001-A, Rev. 5

Because of the number of participants at the EPAC meeting, 70 or more employees from across all Eversource operating companies, these meetings are held via Microsoft Teams. Given the medium, RCG could not determine the participant's level of individual engagement during the session observed by RCG. Further, the SDC meeting is held similarly without as many participants.

Our review shows that the engineering line management structure for the engineering and operations functions is dedicated to robust oversight of the Substation CapEx projects. More on this is provided in the Engineering chapter of the analysis. Further, there is a significant level of person-hours devoted to reviewing projects at multiple levels.

Based on the management interviews and observation of two formal committee sessions involving a significant number of personnel beyond voting members, this process involves a considerable time commitment to review CapEx projects and programs. The two formal bi-weekly meetings occur at the Eversource SDC and (EPAC) levels for substations and New Hampshire PAC for distribution lines. An important point here is some projects will not clear these sessions and will be tabled until they meet the standard design/financial requirements. RCG did not witness extensive questioning on projects in either meeting. Given the size of the EPAC meeting and the number of projects being reviewed, this was not surprising, but RCG would be remiss if we didn't comment on this format. Having such a large forum at EPAC with an unexpectedly lower participant involvement seems counterproductive and may not be supportive of a learning exercise.

SDC reviews the substation engineering projects' technical readiness to move to the EPAC. At this committee, the primary focus is completing the PAC forms and a review of alternatives. RCG considers this to be a pre-screening activity. In addition, before this meeting, SDC team members meet with the project designers to evaluate the worthiness and the technical adequacy of the preparation of documents required by the two committees. The informal SDC pre-meetings function somewhat as an informal peer review described in RCG's CapEx Process but not entirely, since the principal effort of the pre-SDC meetings is to ensure forms are adequately completed.[21]

The purpose of these committees is to move forward those engineering projects to be included in the formal authorized capital plan for PSNH in the form of a *Full Funding Request*. Once approved, the project receives the necessary management signatures consistent with the *Delegation of Authority* policy.

Before full substation project authorization, the engineering of projects is tracked using *PowerPlan*, which follows the project's engineering development estimates through the final *Pre-Constructability Estimate*. *PowerPlan* provides management with critical insights into the formation of the final estimate. However, *PowerPlan* creates several interim "Building Block" estimates as a project moves toward the final *Pre-Constructability Estimate*. When the DOE requests all the estimates associated with a given project, PSNH/Eversource must provide those building block numbers generated from the conceptual engineering estimate through the *Pre-Constructability Estimate*. This can create another point of confusion for third-party reviewers, as PSNH must comply with the request even if the intermediate estimates are only building blocks used to achieve the *Pre-Constructability Estimate*. This situation is aggravated when the estimates provided are not accompanied by appropriately detailed documentation explaining each intermediate estimate's purpose.

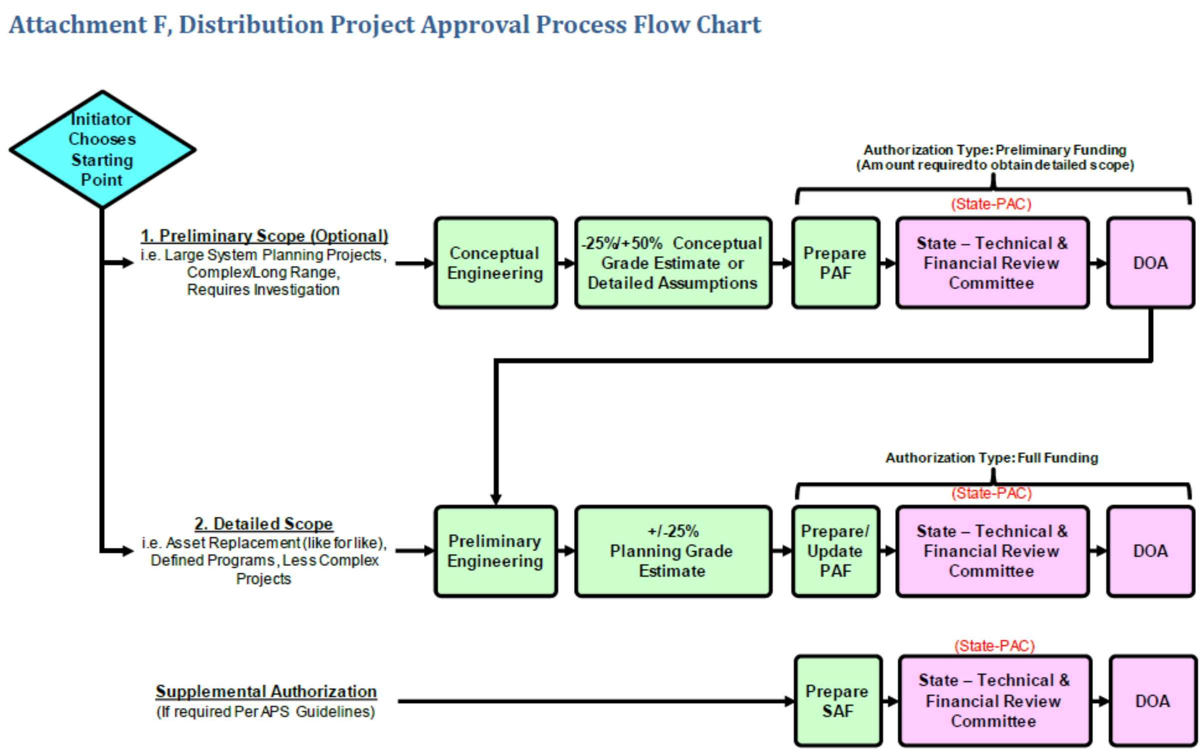
[21] Interview #34

4.3. The Distribution Line projects follow a less complex process but still contain the same concerns related to clear communication and terminology definition.

The Distribution Line Projects process, Exhibit 6, only involves one approval committee, the *NH Project Approval Committee* (NHPAC). Further, the final arbiter is the Director of Distribution Engineering, who also serves on the committee. Projects can be tabled and resubmitted after the identified issues are satisfactorily addressed. RCG learned from the Director that this is a highly iterative process.

As with the substation projects' flow, Supplemental is also used in this engineering process flow. The NHPAC committee is different from the two substation approval committees in that it approves the project technically and financially.

Exhibit 6 - NH Distribution Line Project Approval Process



Capital Project Approval Process - JA-AM-2001-A, Rev. 5

Since these projects are less complex and have a significantly lower dollar value, the need for the same level of rigorous review as the substation design process is less critical. RCG agrees with this determination. Once again, the term "*Supplemental*" surfaces as shown in the above Exhibit and is used similarly as with the substation approval leading to the same type of confusion if the estimate is not the *Pre-Constructability*. Regardless of the project type, either substation or distribution line, the project is managed using *PowerPlan*, which tracks the project's engineering development cost estimates through the final *Pre-Constructability Estimate*. As before, it creates another point of confusion for third-party and regulatory reviewers, even though the Company must comply with regulatory requests. This is particularly true when the estimates lack the appropriate documentation explaining each intermediate estimate's purpose.

The distribution line projects still have a risk component that should be understood and accounted for during the design. Several issues are generally reviewed before a project is approved and the final budget is incorporated into the annual PSNH capital plan. Specifically, these include:

- Soil conditions, rock ledge that could require more time, and the use of special digging equipment,
- Water table depths, where appropriate, could impact the installation process by requiring water mitigation efforts,
- Other in-ground obstacles that would potentially require the relocation of poles or trenches in the case of underground cables,
- Obtaining rights-of-way over private property,
- Tree trimming and removal can, in some locations, be complicated due in part to landowner concerns,
- Municipal roadway requirements, and
- Soil removal and disposal requirements.

Generally, line projects have fewer unique components. PSNH/Eversource has recently changed several design requirement policies to replace worn/aged equipment to improve reliability. In addition, the recent policy changes will improve the purchasing leverage of PSNH/Eversource in general, which in the coming years will lead to better management and predictability of material unit costs for line equipment. Further, it will reduce inventory carrying costs and the overall level of stores by eliminating the need to maintain many different voltage types of the same components. One line hardware component has a side benefit, moving from three other voltage class insulators to standardizing on 34.5kV units will increase the voltage creep distance customarily required for the 12kV and 4kV systems and potentially reduce the need for insulator cleaning on the two lower voltages caused by natural contamination from air-born materials like dirt and salt.

PSNH's tree trimming policy and approach appear adequate for the geography. Issues with tree trimming tend to surface in population centers where property owners live. They have genuine concerns regarding the impact of tree trimming on the aesthetics of their property, which could lead to a perceived lowering of property value. The issue of aesthetics is shared across the electric utility industry, and the solutions can be complicated.

The final approval for distribution line CapEx projects rests with the Director of New Hampshire Distribution Engineering (DoNHDE). The DoNHDE has the final approval and performs any necessary follow-up with the distribution designers, particularly when additional costs exceed the originally authorized CapEx dollars. These overages are tracked by a meeting with the Director to explain the overages.

A pole's typical useful life is dependent on the local climate and soil conditions. Pole loading conditions are another potential issue as well, but this can be managed by the size and type pole used. Several recent storm events brought to light the fragility of some of this inventory, so management changed the policy concerning outcomes from post-third-party inspections. Instead of repairing poles with modest ground line rot issues, the new policy requires that poles be replaced with stronger Class 2 poles***. It is important to stress that the replacement policy is based on potential for pole failure concerns and not on a wholesale pole replacement.*** Interestingly, the Division raised the concern that several poles were replaced in one area that didn't appear to need replacement. RCG investigated the specific situation and learned that a communication company requested the pole changeout to provide better working clearances for their personnel. The communications company paid for this requested work.

Another difference between the substation and line projects is that line projects have a shorter "working" period (from engineering to completed construction). Because line materials don't require the production lead times that substation transformers need, the designs are less complex, and installation is more straightforward. However, we have found that distribution line equipment can occasionally experience supply chain issues.

The above suggests that Line CapEx projects are far simpler and lower cost than substation projects. However, independent oversight of the process and risks should be routinely performed to ensure that operations and management of distribution line projects are carefully following guidelines, and decision-making is within PSNH bandwidths. The defined term "*Supplemental*" is inappropriate for early engineering project design efforts and can create confusion for third-party and regulatory interpretations of the estimates.

4.4. RCG found that PSNH senior management actively monitors the NH capital budget and the individual capital project costs and schedules.

In addition to the EPAC, SDC, and NHPAC, periodic meetings focus on monitoring additional aspects of the CapEx process, as reflected in Exhibit 7.[22] Further, the distribution operations organization holds a daily morning briefing to review the overnight system operational issues, switching plans for the day, and any impacts on the scheduled project work.[23] Considering PSNH's continuing improvement effort to refine their estimating process, RCG believes that the number and frequency of meetings focused on capital projects are appropriate in the short term. However, RCG thinks this level of focus could be unsustainable in the future as management shifts its focus on other pressing business issues.

Exhibit 7 - CapEx Project Process Oversight

PSNH CAPITAL PROJECT PROCESS - MEETINGS AND COMMITTEES

	Committee/Meeting	Procedure	# of Attendees (a)	Duration (b)	Frequency
1	Project Team	M6-PM-2001	~7	~1 hour	Weekly/Bi-Weekly
2	Schedule Review	N/A	~20	2 hours	Weekly
3	Outage Coordination (T&DCC)	N/A	~20	1 hour	Every 2 weeks
4	Distribution Engineering Capital Project Status/Tracking	N/A	~16	90 min	Monthly
5	Joint Planning/Engineering/Operations	N/A	~15	2 hours	Monthly
6	Distribution Engineering Challenge Session	N/A	~20	2 days	Annually
7	Capital Budget Review (CBRC)	N/A	~20	2 hours	Monthly
8	NH Project Approval (NH PAC)	APS-01/JA-AM-2001-A	~10	2 hours	Every 2 weeks
9	Solution Design (SDC)	JA-AM-2001-A	~15	2 hours	Every 2 weeks
10	Eversource Project Approval (EPAC)	JA-AM-2001-A	~22	4 hours	Every 2 weeks

(a) The number of attendees listed above are the attendees that are required to attend. The number of attendees and representatives from different areas of the organization are invited and do attend and will vary depending on the meeting and the the complexity of the agenda topics for that particular standing meeting.

(b) The duration of the meetings listed above is the typical time allotted in the calendar invite. The duration will vary depending on the meeting and the agenda topics for that particular standing meeting. Please refer to the narrative description of each meeting for a more thorough understanding of the duration.

[22] DR BPA-13-007 Att.

[23] Interview #67

4.5. Using the term *Supplemental* before a CapEx project is fully funded and authorized adds significant confusion to non-Eversource reviewers of CapEx projects.

The term "*Supplemental*" is defined in *APS-1* as an addition to an already authorized project budget estimate (comparing actuals to the approved *Pre-Constructability Estimate.)* "*Supplemental*" can also specify a project as it moves into the CapEx management process flow with "*Full Funding*" approved. Before this stage of project development, the early estimates maintained in *PowerPlan* are still preliminary estimates that evolve as PSNH/Eversource engineering or contract engineers progress toward the final design and estimate.

RCG believes that using the term "*Supplemental*" during engineering's project development efforts may have helped lead the Division to misinterpret the provided estimates and select an earlier estimate preceding the *Pre-Constructability Estimate* when making comparisons to the actual project cost. This scenario potentially led to the Division's decision to recommend disallowing a significant portion of a rate increase, followed by the need for this process audit. The Division Staff received all the estimates without sufficient definitions, causing them to select an inappropriate early estimate to conduct their analysis, instead of using the actual final *Pre-Constructability Estimate.*

In the future, any estimate created before a *Pre-Constructability Estimate* should be marked as a ***Design Development Pre-estimate*** so that it cannot be repeated. The purpose is to eliminate confusion for the non-Eversource reader. ***Supplemental should not be applied to any of these building block estimates.***

Recommendations

There are no recommendations for this section.

Engineering and Systems Analysis Functions

5.1	**PSNH/Eversource's engineering departments are structured properly to provide the appropriate level of attention to maintaining and improving the distribution system, consistent with generally accepted industry practices. However, opportunities exist to enhance these efforts.**

The Division had concerns relative to PSNH's approach to developing capital projects for system improvements, customer expansion, and environmental upgrades and to changes made in PSNH's planning criteria which increased the number of potential capital projects. RCG performed a comprehensive review of engineering practices to understand better the appropriateness of policies and processes governing the Company's actions in identifying, designing, and building a robust distribution system. PSNH's engineering CapEx efforts were compared to industry standards by reviewing a subset of capital projects (Appendix D) to determine if policies and processes were consistently applied. Specific engineering designs were not evaluated as this is out of scope for this process audit.

The findings are presented in the Engineering section of this report according to the following subsections:

- *Organization* - reviews the appropriateness of the engineering function;
- *Engineering Project Control Processes* - outlines project development from identification through design-build;
- *Energy Forecasting* - predicts the growth of customers and attendant energy demand and usage;
- *System Planning Criteria* - describes the system planning criteria and technical design guidelines used to identify potential problem areas in the distribution system and associated substations; included is an assessment of the Distribution Pole Replacement Program (pole testing, selection, and replacement);
- *System Planning Studies* - explains how solution alternatives are identified and developed for projects built before and after changes in the planning criteria;
- *Reliability Analysis* - quantifies historical system performance; included is an assessment of Worst Performing Feeders (a statistical performance measure applied to distribution feeders to assist in prioritizing capital projects) and an assessment of system resiliency practices (the adequacy of future system reliability performance); and
- *Distributed Energy Resources* (DERs) System Impact Studies - evaluates the impact of integrating DER into the NH distribution system and the design, engineering, and equipment application measures taken to resolve potential reliability performance and safety issues.

The two most significant areas for improvement are communications (both written and oral) and management oversight of work being performed. The subsections below will illustrate Eversource/PSNH's work in structuring its engineering efforts, with control centered around two distinct management structures: A substation design function and a distribution line function. Both functions appear to be well designed for their respective areas of responsibility.

Communication and potential management oversight concerns will also be addressed as they apply to distribution system planning criteria, study methods, engineering tools, decision processes, and technical standards based on reliability and resiliency improvement projects. Communication was the single biggest issue throughout the CapEx engineering process.

5.2 The Engineering Organization is bifurcated between Eversource and PSNH. Complementary organizational responsibilities are accomplished at the Eversource corporate and PSNH levels that encapsulate the core functions of a robust distribution engineering group necessary to design and enhance the distribution system. A relatively new Grid Mod function has become a core part of the engineering operation.

In certain cases, the Director-level and higher management positions have three-state (CT, MA, NH) responsibilities giving managers the flexibility to assign staff where they are most needed. For processes and technologies to be successful and efficient, each must be interchangeable across all three states[24] (to the extent possible with state-specific voltages and other reasons, including state regulatory commission requirements) and well documented in the Distribution System Planning Guide (DSPG).[25]

In NH, System Planning focuses on substations [distribution, bulk (115kV and above)], non-bulk substations (less than 115kV), and transmission lines (transmission is not directly part of this process review). Responsibilities end at the substation fence (except for transmission and distribution interconnections between substations used to transfer load during a station N-1 event). NH Distribution Engineering is responsible for everything outside the substation fence and works with System Planning on substation feeder connections.[26]

[24] Interview #18
[25] LCIRP, Oct 1, 2020, Appendix D
[26] Interview #13

A *Substation Advanced Analytics Group* was formed by the VP of *Substation & Transmission Engineering* to encourage a forward-thinking atmosphere. When the need for a software tool is identified by engineering, this group will research an outside source or perform an in-house development. This group also ensures that engineers have the best tools for successfully performing their jobs.[27] An example is securing the Electric Power Research Institute's (EPRI) Power Transformer tool (PTX) to support Eversource's power transformer health evaluations. Another example under development is *Smart Inspect*, a machine-learning tool to anticipate pole failures or vegetation encroachment. It has been successfully used in a CT pilot program; MA will be next followed by NH (schedule TBD).[28]

The *Protection & Control* (P&C) group is responsible for:

- All distribution of P&C equipment, application, and settings outside the substation fence (pole-top reclosers, automated switches); and
- All T&D P&C equipment and attendant device settings inside the substation fence (relays, equipment protection, *system control and data acquisition* (SCADA), capacitor bank controls and voltage regulator controls).

The P&C Group designs the protection and control scheme. The Distribution Field Engineering (DFE) group is *appropriately* responsible for managing the distribution pole-mounted voltage regulators and capacitor bank controls & settings. Further, the DFE also correctly handles the fuse sizing or TripSaver application. P&C is responsible for all protection/automation settings (anything that must coordinate), including line reclosers, automated switches, and any communications-related devices.[29]

The *Director of NH Distribution Engineering* is responsible for the NH Distribution system and its five geographic regions. This Director has five managers . . . one for each of the five regions. Each manager has:

- Two or three engineers,
- One supervisor, and
- Eight designers (technicians) reporting to the supervisor.

[27] Interview #15
[28] Interview #15.
[29] Interview #34 and Interview #21

The designers use Maximo (or Storms which Maximo is replacing) to design distribution projects. A "design" includes anything from line extensions, reconductoring for load growth, and pole-top distribution automation down to fused cut-outs. This group designs everything along the streets but is not responsible for day-to-day issues handled by Distribution and Field Engineering by using daily calls to review outages affecting more than 100 customers.

Action plans are prepared if a device has been impacted three or more times in 90 days or if the device has a high customer count.[30] Engineers are responsible for high-level designs, e.g., "We need to run a wire from here to there, or an underground circuit needs to happen." It is then assigned to the designers to complete project design details.[31]

There is also a *Director of Distribution Technical Engineering* (DTE) with three-state responsibilities. Reporting to DTE:[32]

- *A Resiliency Group* that coordinates Distribution Automation (DA) designs;
- Three single-state managers for *GIS* and associated standards; and
- There is one three-state Manager for *Reliability and Resiliency.* The position was vacated in July 2021 due to retirement and was filled in July 2022, which is now reporting directly to the VP of System Planning. The Director of NH Distribution Engineering handled budget and planning issues for NH in the interim, and the Director of DTE was addressing reliability (alongside the Director of NH Distribution Engineering) and resiliency issues in NH through early 2022.

The Manager of *Substation Design Engineering* (SDE) reports to the Director of Substation Design and is responsible for substation asset management in NH. While SDE is not involved with physical testing, SDE is responsible for "Asset Management" (evaluating device conditions and acting on test results). If an asset needs to be replaced, SDE is responsible for the associated design. SDE does not use Storms or Maximo like distribution line engineers and technicians but instead locate stock codes and procure equipment.[33] Asset Condition, System Planning, and SDE groups work closely together.[34] SDE's key concern is having adequate capital funds to complete multi-year programs. Recognizing the capital budget is fixed, SDE competes for annual capital funds for every project and program.

[30] Interview #16
[31] Interview #11
[32] Interview #11
[33] Interview #61
[34] Interview #13

The Manager of Protection & Control Compliance, Standards and Support reports to the Director of Protection & Control Engineering and has three-state responsibilities, including standardizing P&C designs, protection schemes, philosophies, and equipment for the different primary voltages.[35]

5.3 Although New Hampshire's Grid Mod's efforts are in the early stages, PSNH is performing needed functions to incorporate Grid Mod into the distribution system.

Grid Modernization (Grid Mod) Programs are rapidly becoming the norm across the industry. Eversource's *Grid Mod Group* was formed to implement Grid Mod programs. Unlike Massachusetts and Connecticut, New Hampshire's Grid Mod efforts are in the early stages.

Groups like PSNH's *Grid Modernization Group* are becoming popular across the electric industry as utilities need to identify better ways to gather system data through enhanced visibility on the grid and to increase automation necessary to provide reliable service in an increasingly decarbonized grid with high DER integration and rising electrification.

The *Grid Mod Group's* strategic goal is to evaluate and implement new technologies and solutions that will benefit system performance/operation, including the following responsibilities:[36]

- *Deploying software solutions*: Collaborating with System Operations and Distribution Engineering to deploy software to control and optimize the grid, using DER to manage peak demand, reduce energy, and control voltage. These software tools establish a flexible DER platform to help facilitate adoption.[37]
- *Facilitating the use of real-time technologies:* Collaborating with engineering to implement new real-time technologies and develop multiple use cases.

[35] Interview #34
[36] Interview #19
[37] Interview #19

In their charter for facilitating new real-time technologies, the *Grid Mod Group* is responsible for delivering the following software solutions:[38]

- *Synergi* (a software tool for steady-state distribution planning and analysis) implementation,
- *Distribution Management System* (DMS) implementation (scheduled for completion in 2022[39]); to add fault location intelligence,
- *Geographic Information System* (GIS) consolidation, and
- *Outage Management System* (OMS) upgrade Storms-to-Maximo.

The Grid Mod Group routinely collaborates with System Planning, Distribution Engineering, and Substation Engineering to accomplish these objectives. This Group is not responsible for system design (circuit ties or DA location/selection, NWA solutions) which is the responsibility of System Planning, Distribution Engineering and Substation Engineering.

A formal Grid Mod Program had been proposed for New Hampshire, but the PUC has yet to approve the funding. In the interim PSNH plans to work with stakeholders and the DOE to identify potential future investment opportunities.[40] So far, PSNH has identified the following program objectives:[41]

- Increase system efficiency and reduce demand;
- Advance penetration of DA and control to the customer meter (grid edge); and
- Facilitate integration of clean energy solutions.

High-potential projects involve the use of new technologies not currently part of PSNH's capital plan. For example, volt-var optimization (VVO) and conservation voltage reduction (CVR) programs are not part of existing PSNH capital budgets but are included in Eversource plans to improve operating efficiency, reduce costs, and enable DER.[42]

Eversource supports grid modernization programs managed by the Grid Mod Group to justify the accelerated deployment of microprocessor relays with advanced distribution automation on primary feeders. This would facilitate more extensive use of automated controls and advanced protection schemes, enhanced use of existing resources, and reduced technical barriers to DER integration.

[38] DR BPA 6-004, page 2
[39] Interview #16
[40] DR BPA 6-004 and Interview #19
[41] Id
[42] Interview #19

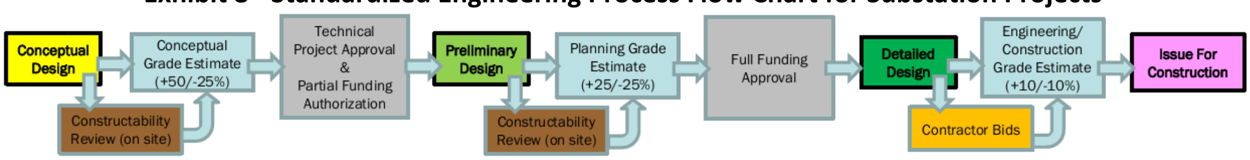
5.4 Engineering and Project Control Processes are well thought out and reflect elements found in other leading utility engineering organizations.

In 2018, Eversource implemented standardized processes and controls for Connecticut, Massachusetts, and New Hampshire for project engineering and project management to improve communications between departments and to facilitate/improve the capital approval process. Eversource recognized incomplete or poorly written design documentation could lead to projects being rejected or underfunded. Section 5.7 - below will review and comment on these processes.

5.5 Eversource's Substation Design and Engineering has a formal process for project development and design that is divided into four distinctive phases. This overall design process is excellent and consistent with industry practices.

The exhibit below shows the standardized process flow chart for substation engineering projects.[43]

Exhibit 8 - Standardized Engineering Process Flow Chart for Substation Projects



Engineering Packages	Alignment with Project Authorization Process
Conceptual Design	For each alternative as required to support cost/benefit analysis of solutions. Typically for partial funding authorization
Preliminary Design	Required for all projects seeking full funding.
Detailed Design	Supports RFPs for outsourced construction services. Bids received for outsourced construction and materials (based upon Detailed design) are used to complete +10/-10% level estimate. The Engineering grade estimate is typically used to obtain subsidiary board approval for large complex projects.
Issue For Construction	Final conformed drawings reflecting all details, final mfg. drawings, construction sequencing, etc. included in +10/-10% estimates and final conformed construction contracts.

Four phases of engineering design are identified and used throughout the Capital Project Engineering process. As the design progresses, assumptions and estimates become more complete, and specific design details emerge. The four engineering design phases, descriptions, and deliverables are described below.[44]

- *Conceptual Design* – Uses historical site-specific data and conservative assumptions; satellite images; typical physical design/layout drawings; existing electrical drawings; and assumed capacity requirements. Conceptual

[43] Eversource NH Business Process Audit Kick-off Meeting, November 4, 2021, slide 9

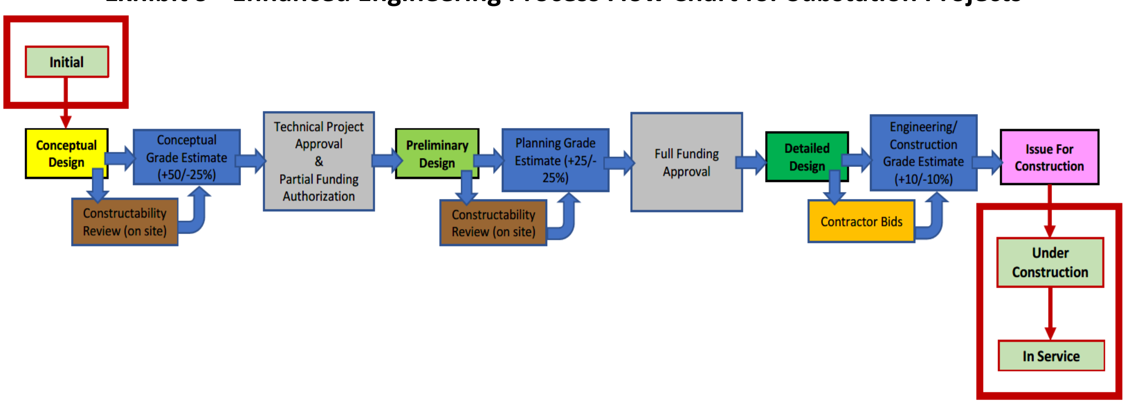
[44] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slides 10-11

constructability reviews are conducted by engineering and operations to provide initial preliminary design feedback. Conceptual layout drawings: electrical one-line diagrams and long-lead-time material lists are created.

- *Preliminary Design* – Preliminary site development requires above/below grade site-specific testing/analysis to mitigate potential cost impacts due to soil contamination, rock/ledge removal, and other unknown below-grade issues. Historical data begins to replace estimates and assumptions. Preliminary conceptual design constructability reviews are conducted by engineering and operations to provide more detailed feedback for the detailed design. These design elements include preliminary line routings, structural calculations, evaluation of DC battery system and loading impacts, AC station service analysis to produce a preliminary site and layout drawings; and major material lists.
- *Detailed Design* – Detailed final plans include physical site drawings; line routings; structural drawings; detailed bill of materials, electrical connection details; one-line metering & relaying diagrams; relay setting plans; AC and panel drawings; wiring diagrams; cable schedules; certified manufacturers drawings; construction plans; outage/energization plans; testing requirements; and site-specific constraints/risks.
- *Issue for Construction* – Final constructability review takes place; contractor bids are issued/reviewed, and drawings are issued for construction (IFC).

Three additional project phases do not appear in the above process flow chart but are added in the flow chart below and are circled in red to highlight their placement. These phases are Initial, Under Construction, and In-Service. [45]

Exhibit 9 - Enhanced Engineering Process Flow Chart for Substation Projects



[45] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slide 13

Systematically moving from the initial design phase to the final in-service phase produces a defensible design, replacing unknowns with actual, site-specific information. RCG believes this to be a solid approach generally followed by the industry.

5.6 The number of project cost estimates can cause confusion.

The substation CapEx process can be overly complex and potentially overwhelming to those not intimately involved, leading to misunderstandings, communication problems, and unrealistic expectations, specifically for non-Eversource entities. This is especially true when engineering produces several different cost estimates. For example, the following five phases have been given specific cost estimating guidelines: [46]

- Initial Phase: -50% -to- +200%;
- Conceptual Phase: -25% -to- +50%;
- Preliminary Phase: -25% -to- +25%;
- Issue For Construction Phase: -10% -to- +10%; and
- Under Construction Phase: -10% -to- +10%.

If the cost estimates are not associated with the appropriate design phase and corresponding deliverables, miscommunications and unrealistic expectations can quickly occur. RCG suggests the following estimates could be enough:

- Initial Phase estimate;
- Preliminary Phase estimate; and
- Issue for Construction Phase (Pre-Constructability) estimate, the precursor to Full Funding Authorization.

Written communications are often unclear, e.g., "Issue for Construction" is also referred to as the "Pre-Construction Estimate." RCG believes this level of inconsistency exists within Eversource and serves to add confusion to the process and estimating practices.

The Distribution Project Approval Process is less complex than for substation projects. While the overall process is good, communications (especially terminology) both inside and outside the Company could be improved. The Distribution Project Approval Process Flow Chart and related observations are provided in earlier sections of this report.

[46] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slide 12

5.7 Enhanced documentation and communication elements are needed to ensure clarity of the Standardized Process Flow Chart for Project Controls, as both are critical for a successful project.

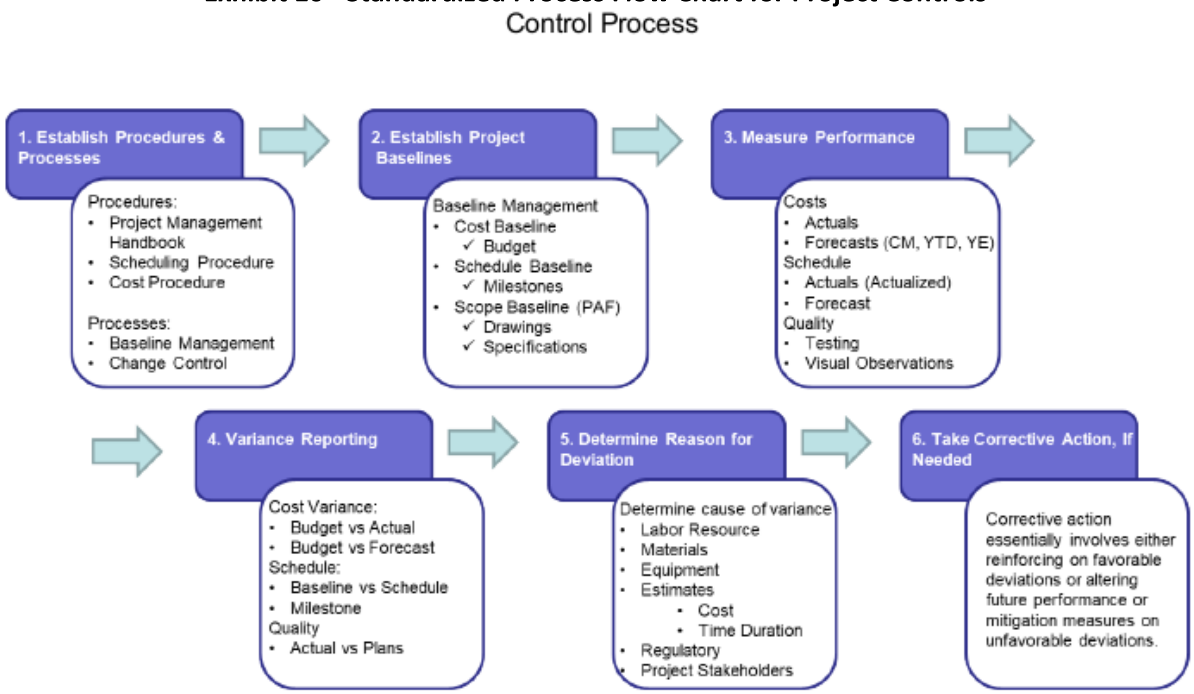
The standardized process flow chart used by Eversource for Project Controls is summarized in the Exhibit 10 below.[47]

The six process elements shown are consistent with responsible actions for any project. However, the following should also be an integral part of the flow chart and prominently identified even if included in the *Project Management Handbook* (control process element 1):

- Documentation - How information is to be documented and archived for each project element.
- Communication - The approach for information flow within the PSNH/Eversource.

[47] Eversource NH Business Process Audit Kick-Off Meeting, November 4, 2021, slide 15

Exhibit 10 - Standardized Process Flow Chart for Project Controls



5.8	**Project Challenges; Executive Technical challenges documented in earlier sections of this report are central to moving projects forward. However, formal peer challenges were not obvious to RCG.**

As noted in earlier sections of this report, executive challenges are well documented. However, formal peer reviews (if they do occur) are not documented. During RCG's data-gathering efforts, especially from an interview, informal peer reviews appear to occur. The regularity of these reviews was not obvious to RCG.

5.9 Project alternatives are not maintained once management makes its final selection.

RCG attended an NH-PAC meeting on May 18, 2022, where a project was being discussed, including solution alternatives. Once the preferred solution was agreed upon, the Director of Distribution Engineering, the person keeping minutes deleted alternatives from the project documentation. While this simplifies the resulting documentation, it provides an incomplete formal record of considered alternatives. This act is transactional and not strategic and does not recognize the potential future need for defending the preferred solution. This represents a lost opportunity for improving future communications and facilitating project approvals.

5.10 PSNH's load forecast process is consistent with utility practice, the methodology for developing substation level loads is a leading practice and the results are reasonable for distribution planning purposes.

PSNH's peak load forecast methodology is consistent with standard utility practice, and its use of econometric models to establish the forecast for bulk distribution substations is a leading industry practice.

At a utility, an accurate load forecast is the foundation for effective capital planning. Contingencies, criteria violations, and other indicators of the need for changes to existing facilities or the need for additional facilities cannot be established without the load forecast. Utilities routinely produce an annual system peak demand forecast for planning and operational requirements and a sales forecast for financial needs. The utility load forecasting process uses models incorporating relevant aspects of the service territory, such as the number of customers, household income, employment, and other variables established to be relevant often by statistical analysis. End-use models, including appliance saturation and usage parameters, are sometimes relevant to a utility's load forecasts.

PSNH's econometric[48] load forecasting model uses industry-standard inputs.[49] These inputs include weather (prior 10-year information of three-day weighted THI (temperature humidity index)),[50] which is similar to ISO-NE.[51] The forecast of econometric

[48] Interview #38
[49] Interview #38
[50] Interview #38
[51] Interview #38

data inputs is obtained from an independent outside vendor (Moody's Analytics).[52] The variables driving the model are evaluated each year and updated as required.[53] The underlying system peak demand forecast is developed independently from the system and distribution planners.

PSNH's load forecasting model produces a 10-year system peak demand forecast[54] and includes a Weather Normal 50/50 forecast and an Extreme 90/10 forecast, meaning one chance in ten of occurring. The system peak model is considered accurate to within 2% of the weather-adjusted peak[55].

Each bulk substation is forecasted as a portion of the system peak load using an econometric model related to that substation.[56] The bulk substation model is considered accurate to within 4% of the two-year average.[57] The Load Forecasting group works collaboratively with distribution engineers to fine-tune the bulk substation forecasts.[58] For example, load shifts between feeders are recognized in the collaborative process.[59]

Additional inputs to the load forecasts include[60] energy efficiency instigated by PSNH. Account executives provide localized known changes,[61] and other step load increases[62] are incorporated within the bulk substation forecast.

The level of solar generation,[63] including customer scale and larger solar generation installations, is forecast with input from Distribution Planning. However, solar does not materially impact bulk substation peak load without associated storage due to timing (between solar peak and system peak) and variability (weather-related).[64] Electric vehicles[65] are estimated within the load forecasting process, although vehicles are a learning process in the current fleet (non-personal) due to the limited data available[66].

[52] Interview #38
[53] Interview #38 and DR BPA 15-4
[54] Interview #38
[55] Interview #38 and DR BPA 15-5
[56] Interview #38 and DR BPA 15-8
[57] Interview #38 and DR BPA 15-6
[58] Interview #38 and DR BPA 15-9
[59] Interview #38
[60] Interview #38
[61] Interview #38 and DR BPA 15-7
[62] Interview #38
[63] Interview #38
[64] Interview #38
[65] Interview #38
[66] Interview #37

The peak load process starts in October after the summer peak season and is finalized by February.[67] The sales (revenue) forecast, which is financially focused, is completed by September.[68]

5.11 System Planning Criteria PSNH/Eversource system planning criteria, design standards, and document control are consistent with industry practices. The Engineering Standards Bookshelf implemented by Eversource is an industry-leading practice.

Electric power systems are expected to reliably supply power to various loads under changing weather conditions. To ensure system designs meet these expectations, system planners use pre-determined performance criteria and digital models to proactively identify system abnormalities or violations (PSNH/Eversource terminology) against one or more criteria. Over the years, the industry (IEEE, EPRI, NREL, DOE, EEI, NRECA, NESA, and others) developed equipment application standards (e.g., ratings) and system metrics (e.g., reliability indices) to be used by system planners and design engineers to quantify system performance.

The *Engineering Standards Bookshelf* implemented by Eversource provides:

- A simplified approach to essential document access for all within PSNH/Eversource, and
- Ensures the latest versions are in one place and easy to access, reducing engineering design/equipment application errors and facilitating training requirements.

PSNH's system planning criteria and design standards are discussed in the following pages.

[67] Interview #38
[68] Interview #38

5.12 System planning criteria within the *Distribution System Planning Guide* (DSPG) apply to all three states while respecting state-specific voltages and system conditions. RCG believes this process to be consistent with a well-functioning engineering organization. However, having multiple documents can create a source of confusion in written communications which can be avoided by releasing a more complete (revised and combined) version of DSPG 2020.

The *Distribution System Planning Guide* (DSPG 2020)[69] is a standard for all three states to harmonize planning criteria and equipment application guidelines as much as practical. Past practices, existing practices, documentation, and industry practices are referenced in the Guide. State-specific exceptions are defined. Resource sharing is supported across all three states for processes and technologies where interchangeability is appropriate.[70] DSPG 2020 contains the following major elements: [71]

- Detailed system planning criteria;
- Asset rating criteria;
- Planning methodology to avoid capacity, voltage, and reliability violations:
  - Model development guidelines: Data imported from GIS; linked demand and DER data; and daily (24-hr)/yearly (8760-hr) planning scenarios;[72]
  - Study methods/procedures;
  - DER applications including Battery Energy Storage Systems (BESS);
  - Load forecasting (reviewed in an earlier section of this report);
  - Solution development procedures/guidelines;
  - Planned and proposed system upgrades (capital planning process).

Non-Wires Alternatives/Solutions (NWAs or NWSs).

A separate, more comprehensive *DER Planning Guide* is to be published by year-end 2022.[73] PSNH plans to address 90% of the issues at publication time, then revise as needed.

Existing planning criteria for all three states are extensively reviewed by engineering when developing the DSPG. The goal is to reduce the risk of sizable events [single contingencies (N-1) lasting one 24-hour cycle] by making the criteria more stringent so engineers can identify reliability risks and proactively design mitigating solutions.[74] Reliability metrics are tracked on multiple timescales and reported to the NH

[69] LCIRP, October 1, 2020, Appendix D
[70] Interview #62, Interview #18, and DR BPA 13-001, page 2
[71] LCIRP, October 1, 2020, Appendix D, Bates pages 106-109
[72] LCIRP, October 1, 2020, Appendix D, Bates page 72
[73] Interview #62
[74] Interview #18

PUC frequently. The responsible reliability planning group, in collaboration with distribution engineering and operations, analyzes the data to identify potential trends and causes and develops plans to mitigate root causes and update standards and practices that improve reliability (reliability performance will be discussed in a later section of this report).

From PSNH's perspective, for the electric grid to accommodate the increased emerging electrification, it requires careful system planning and associated grid investments for reliability and resilience. Today's customers have transitioned from simple tasks such as lighting, refrigeration, cooking, and water heating to more complex and dependent energy needs.[75] Many customers are now working at home and using computers more intensely than at the turn of the century. Simple mechanical thermostats have evolved and now perform complex control of space conditioning. Typical household appliances now have computer chips that optimize how they operate. Entertainment is no longer a simple television. This evolution is expected to continue as the economy further electrifies with new uses such as electric vehicles. Consumers have a real need for a continuous, high-quality electric power supply. In many respects, this shift has been accelerated by the recent pandemic.

The ability to transfer load between substations during a system contingency is key to reliability. Having transformers not loaded to the nameplate when an event happens makes load transfer possible. For NH, (N-0) bulk transformer criteria were changed from 75% (*SYSPLAN-010*) to 95% (*DSPG 2020*) of nameplate rating, reducing the ability to accept load transfers from neighboring substations. However, this was considered an acceptable risk due to the unique nature of the PSNH system and the ability of the 34.5kV backbone distribution lines to carry the additional load.[76]

In addition, legacy guidelines allowed bulk transformers to be loaded to their long-term emergency (LTE) ratings under normal (base case) (N-0) conditions. The new criteria limit loadings to 100% of the nameplate (i.e., the LTE load-ability rating was lowered), leading to more guideline violations.

The comprehensive Exhibit 11 summarizes new *DSPG* planning criteria for bulk/non-bulk transformers and distribution lines for normal (N-0) and contingency (N-1) conditions and compares them to the old criteria. *ED-3002* was issued initially on January 10, 2003, as the primary guidance document for NH system planning until *SYSPLAN-010* was created in 2014. In 2018, the three states' planning criteria were combined into a single revised *SYSPLAN-010* document that was to supersede *ED-3002*.

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[75] RCG's anecdotal experience indicates customer's tolerance of outages (even during major storms) has markedly decreased over time.

[76] Interview #18

The primary guidance document (*SYSPLAN-010*) was revised again in September 2020, creating the new *DSPG 2020* document used today. Updated system planning criteria, equipment ratings, and planning methods/guidelines are included in *DSPG 2020* which was intended to supersede *SYSPLAN-010* and *ED-3002*. However, not all items were moved to *DSPG 2020* creating the need for *SYSPLAN-010* and *ED-3002* to act as supplements (despite both being superseded) until a more comprehensive *DSPG* can be written.[77]

The adoption of *DSPG 2020* coincides with the PSNH's transition to Synergi as a load flow planning tool with abilities to incorporate probabilistic simulation approaches and new DER modeling capabilities.[78] As PSNH organic DER penetration levels increase, the modeling features of this tool are expected to facilitate DER hosting/integration studies which are addressed in *DSPG 2020*.

In the NH *July 2020 Load Flow Study Report*,[79] the following violations were identified for bulk transformers and connected distribution lines:

- 2020: 3 xfmrs on N-0 3 ckts on Voltage 23 subs on N-1
- 2021: 1 xfmrs on N-0 0 ckts on Voltage 0 subs on N-1
- 2022: 0 xfmrs on N-0 0 ckts on Voltage 2 subs on N-1
- 2023: 0 xfmrs on N-0 0 ckts on Voltage 0 subs on N-1
- 2024: 0 xfmrs on N-0 0 ckts on Voltage 0 subs on N-1

While the criteria change from 75% top nameplate rating to 95% will reduce the number of transformer design violations, the considerable variation in the year 2020 compared to the years 2021-2024 can be attributed to an PSNH criterion not discussed above. Before the change, 30 MW of load could be dropped for up to 24 hours for any single contingency condition (e.g., a bulk station transformer failure).[80] Mobile transformers were then relied on to restore power within 24 hours.

In the new criteria, all loads must be immediately restored (i.e., can no longer drop 30 MW) using automatic bus switching schemes. (Note - no capital projects were initiated from 2018-2020 under *SYSPLAN-010*).[81] Bus-tie breakers allow this to occur by connecting the primary bus's live section to the primary bus's dead section, restoring supply across the entire substation primary bus. This use of the bus-tie breaker scheme shows its innate

[77] DR BPA 10-005, pages 1-2
[78] DR BPA 13-001
[79] 2020 to 2029 Load Flow Study Report, July 1, 2020, LCIRP Appendix B-1
[80] ED3002
[81] LCIRP, October 1 2020, p23 of 45

value in protecting the system. The faulted circuit or transformer is separated, via another breaker, from the bus until repaired.

Exhibit 11 - System Planning Criteria – Comparison of Old vs. New DSPG 2020[82]

Document:	ED-3002	SYSPLAN-010	DSPG 2020
Jurisdiction:	NH	CT-MA-NH	CT-MA-NH
Primary Criteria Document:	1/10/2003-8/1/2018	8/1/2018-9/22/2020	9/22/2020-Present

Bulk Transformers (115kV and above)			
(N-0) Normal Operation (Base Case) - Violations Criteria			
	ED3002	SYSPLAN-010	DSPG 2020
Bulk Transformer Loading	115% - 150% top nameplate rating (TFRAT)	> 75% top nameplate rating	CT-MA: > 75% top nameplate rating NH: > 95% top nameplate rating
Voltage, Unregulated Load	< 97.5%	n/a	n/a
Voltage, Regulated Load	< 95%	n/a	n/a
Voltage, Service	n/a	< 95%	< 95%
Load Block Transfer Limit	n/a	n/a	n/a
Remaining Isolated Load	n/a	n/a	n/a
(N-1) Contingency - Violations Criteria			
	ED3002	SYSPLAN-010	DSPG 2020
Bulk Transformer Loading	115% - 150% top nameplate rating (TFRAT)	> 100% LTE	> 100% LTE
Bulk Substation Loading	n/a	> 100% STE_{N-1}	> 100% STE_{N-1}
Voltage, Unregulated Load	< 95%	n/a	n/a
Voltage, Regulated Load	< 92.5%	n/a	n/a
Voltage, Service	n/a	< 95%	< 92%
Load Block Transfer Limit	3	3	3
Remaining Isolated Load	30MW load out for up to 24 hrs	> 0 MW (no loss of load)	> 0 MW (no loss of load)
Transmission Supply N-1	30MW load out for up to 24 hrs	> 0 MW (no loss of load)	Single Transmisison N-1 shall not cause greater than a single Distribution N-1 condition.

Non-Bulk Transformers (below 115kV)			
(N-0) Normal Operation (Base Case) - Violations Criteria			
	ED3002	SYSPLAN-010	DSPG 2020
Non-Bulk Transformer Loading	115% - 150% top nameplate rating (TFRAT)	115% - 150% top nameplate rating (LTE)	> 100% top nameplate rating
(N-1) Contingency - Violations Criteria			
	ED3002	SYSPLAN-010	DSPG 2020
Non-Bulk Transformer Loading	> LTE rating for 1 load cycle; mobile transformer to be installed within 24 hrs if circuit ties not available	> LTE rating for 1 load cycle; mobile transformer to be installed within 24 hrs if circuit ties not available	> LTE rating for 1 load cycle; mobile transformer to be installed within 24 hrs if circuit ties not available

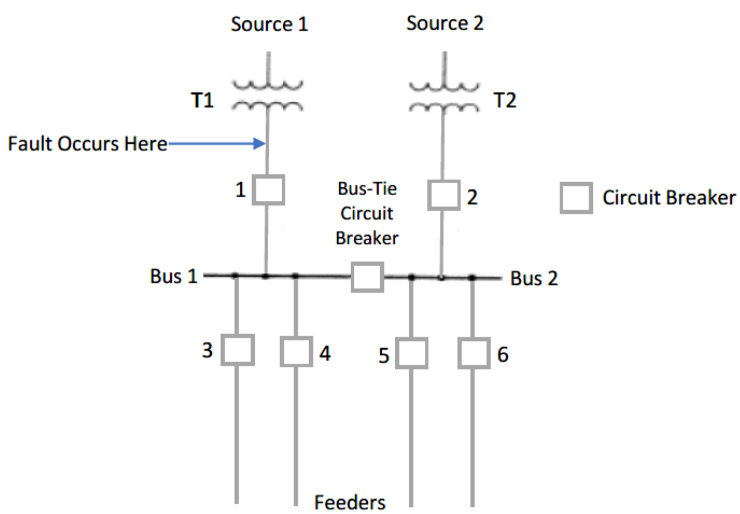
Distribution Lines			
(N-0) Normal Operation (Base Case) - Violations Criteria			
	ED3002	SYSPLAN-010	DSPG 2020
Line Loading	> 100% normal	n/a	n/a
Line Loading, Overhead	n/a	> 100% normal	> 100% normal
Line Loading, Underground	n/a	> 100% normal	> 100% normal
(N-1) Contingency - Violations Criteria			
	ED3002	SYSPLAN-010	DSPG 2020
Line Loading	> 100% emergency	n/a	n/a
Line Loading, Overhead	n/a	> 100% emergency	CT-MA: > 100% normal NH: > 100% emergency
Line Loading, Underground	n/a	> 100% normal	> 100% normal

[82] DR BPA 10-004, Attachment BPA 10-004.xls

In addition, PSNH added a single-contingency (N-1) transmission requirement to minimize the impact on the distribution system (i.e., shall not cause more than one distribution N-1 condition) resulting from outages on the transmission system. This policy change means a contingency condition on the transmission system shall not cause more than one contingency condition on the distribution system.

The bus fault criteria specified in *DSPG 2020* is a standard industry practice. A bus or busbar is a connection point for power systems, transmission lines, and distribution feeders. If a fault occurs electrically close to a busbar (e.g., on the T1 low voltage terminal in the exhibit below), all circuits supplying fault current (source side) to the busbar must be tripped (disconnected) to isolate the fault and prevent damage to the system (CB1).

Exhibit 12 - Bus Tie Example



A series-bus-tie breaker connects two buses (Bus 1 and Bus 2) and is normally open (for this example). This design improves reliability in that if a fault occurs on one bus (Bus 1), the normally open series-bus-tie breaker is closed (after confirmation CB1 is opened), and loads (feeders) are then transferred from the faulted bus (Bus 1) to the unfaulted bus (Bus 2), maintaining service continuity (limited only by equipment ratings). For loads that can be restored in less than five minutes, SAIDI (duration) reliability performance statistics are not impacted.

As a result of using this new criterion to perform the annual 10-year load flow study, 2020 saw the potential for an increase in violations. With forecasted load growth at only 0.38%, potential capacity violations were expected to substantially decrease in the years 2021-2024.

Despite the relatively large number of 2020 violations, only the highest priority capital projects were submitted in 2020 to avoid exceeding the total annual capital budget of $140M.[83] As a result, Distribution Engineering is working with Distribution Planning to prioritize the violations and corresponding project solutions. The prioritization process considers several factors (for example, asset condition). The highest priority projects are identified in the 5-year capital plan along with the selection rationale. RCG believes this set of actions shows the Company's commitment to maintaining approved annual capital budget limits.

PSNH believes the criteria changes have created a point of disagreement and an atmosphere of distrust with the Division. PSNH is of the opinion that Division believes PSNH should take more risk, not less, to control capital dollars and resulting rate structures. PSNH also believes consumer advocates are also pushing for more risks to be taken to keep rates low. [84]

From PSNH's perspective, PSNH is working on providing reliable electric service to its customers, as needed in a changing grid with electrification trends and climate change related extreme events. These two emerging trends require continuous grid investments with careful utility system planning.

5.13 PSNH's use of tree wire is appropriate. RCG supports the *selective* use of tree wire (covered wire) in areas with a high frequency of tree–wire contacts leading to outages.

PSNH strongly believes it is essential to anticipate future conditions and take proactive planning measures before reliability becomes a significant problem. An example would be the selective application of covered tree wire in areas prone to multiple faults due to tree limb contact (but not falling trees).[85] Division Staff have interpreted this use of tree wire as indicative of an overbuilt system. However, selective use of covered wire in highly treed areas with frequent tree contact issues is consistent with leading industry practices.

[83] Interview #20
[84] Interview #20
[85] Interview #11

5.14 PSNH's change in planning criteria should be better explained. RCG believes PSNH did not sufficiently explain the rationale behind changing the planning criteria to the Division.

Another RCG concern was the change from allowing a 30-MW load loss over 24 hours to a 0-MW load loss which was interpreted by the Division as going too far and believing more risk should be taken (i.e., some MW load loss is OK), which led to a different philosophy between PSNH and Staff.[86]

This difference in philosophy leads to differing views on what qualifies as a violation. Eversource believes PSNH is "incredibly frugal" in the design and build of the distribution system[87], which is why the system is designed around a 34.5kV distribution backbone (i.e., transformed directly from 345kV transmission to 34.5kV distribution) and why projects are evaluated/prioritized on a cost-per-customer-saved-minute basis.

PSNH did include in its 2019 LCIRP filings an explanation for why criteria changes were needed.[88] A settlement agreement with Staff was reached and approved in October 2019 that included language about criteria change disagreements, stating investments made solely based on these changes could continue subject to prudency reviews. Those disagreements were ultimately settled in PSNH's subsequent rate case whereby PSNH agreed to return to less conservative criteria.

5.15 PSNH appears to be complying with industry accepted design practices.

Standard designs have been adopted across all three states as much as practical, recognizing state-specific requirements apply. Standard substation designs are modified to fit need/cost targets, e.g., more expensive breaker-and-a-half schemes will not be used if less expensive straight-bus designs satisfy design/performance criteria.[89]

Most (90%) substation engineering work occurs at existing brownfield sites where standard designs typically do not apply. Instead, existing design alternatives are considered when developing solution alternatives. Selecting the preferred alternative (best overall solution) involves evaluating a matrix of weighting factors (pros/cons, criteria, maintenance costs, logistics, overall costs). Suppose the least-cost solution creates future maintenance concerns (e.g., equipment no longer supported by the

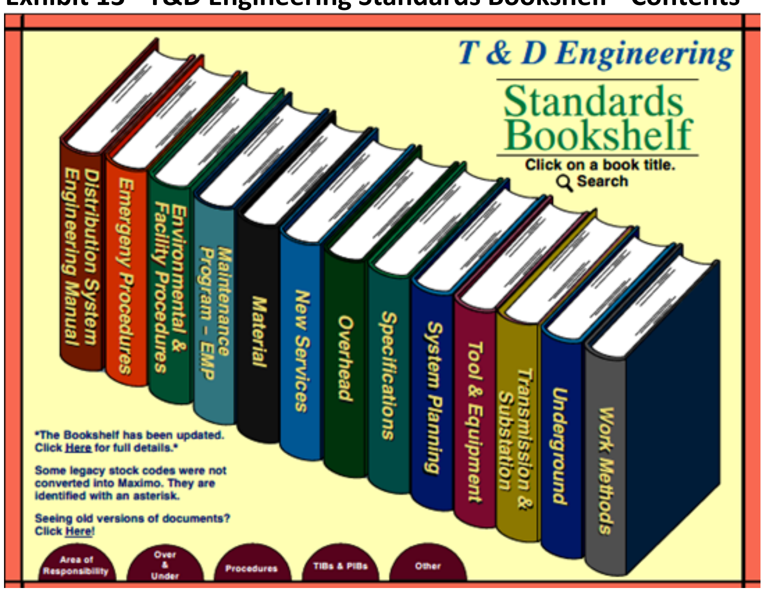
[86] Interview #20
[87] Interview #20
[88] Interview #20
[89] Interview #21

manufacturer) or comes with specific reliability concerns (e.g., animal protection). In that case, a higher initial-cost solution option may be selected instead.[90]

Replacing old transformers at existing substations is possible, even with space limitations, because new transformer designs tend to be physically smaller. However, with older substations, there are usually other issues that need attention resulting in the need for a substation rebuild (e.g., aging equipment, obsolete technologies, eliminating equipment with hazardous fluids, and difficulty obtaining spare parts).[91]

Standard distribution transformer designs are included in Storms/Maximo according to the *Distribution System Engineering Manual* (DSEM). Standard substation designs, including transformers, are in the Substation Design Manual (SDM). Both DSEM and SDM are part of the *Engineering Standards Bookshelf* shown in the exhibit below. When designing distribution lines, field design engineers/technicians use DSEM-published designs. For PSNH distribution step-down transformers, for example, there are 28 unique design configurations.[92]

Exhibit 13 - T&D Engineering Standards Bookshelf - Contents*[93]*



DSEM does not address every situation. Decisions can incorporate project-specific requirements that may impact the best overall solutions, e.g., conditions set forth by state regulatory bodies.[94] DSEM contains 19 sections covering distribution system design (e.g.,

[90] Interview #21
[91] Interview #73
[92] DSEM, November 2015, Section 14.34, Table 5.
[93] DR BPA 15-001, Attachment BPA 15-001(a)
[94] DR BPA 9-001

reliability, power quality, overhead, underground, protection) and equipment application (e.g., conductors, arresters, capacitors, transformers, regulators). *DSEM* also addresses safety, voltage regulation, reliability, flexibility, capacity, and economics.[95] Sections are succinctly written and to be used in conjunction with other, more detailed standards (e.g., *DSPG*).

5.16 PSNH's use of substation feeder protection standards are appropriate. Substation feeder protective device application standards/guidelines, and bulk and non-bulk distribution supply transformer overcurrent protection standards/guidelines appear well written, appropriate, and complete.

Eversource uses protection standards and guidelines developed internally by the Protection & Control (P&C) Department. They describe the protection philosophy, type of protection, and applicable industry standards. Protection documents are periodically reviewed and revised as protective device technology evolves and improved protection schemes are adopted.[96] The two example documents reviewed by RCG (*Substation Feeder Protective Device Application Methodology*[97] and *Bulk and Non-Bulk Distribution Supply Transformer Overcurrent Settings*[98]) appeared to be well written, appropriate, and complete from an engineering point of view.

Eversource participates in the following industry meetings/conferences: IEEE; NESC; EPRI; NATF; AEIC; IEEE Power System Relay Committee (PSRC); North American Transmission Forum Protection System Working Group; local IEEE; and NPCC. However, meeting highlights are not consistently shared within the engineering organization,[99] creating missed opportunities for professional development and pointing to another example of missed communication.

All changes to T&D procedures are controlled by TD001 in the Document Control Process managed by T&D Standards Engineering.[100]

Hardware is standardized to increase overall efficiency when possible. For example, 34.5kV pole line hardware is also used on 12kV and 4kV systems to simplify the

[95] DR BPA 4-02, Attachment 1, DSEM link
[96] DR BPA 1-029
[97] DR BPA 1-029, Attachment A
[98] DR BPA 1-029, Attachment B
[99] Interview #61
[100] DR BPA 15-001, Attachment BPA 15-001(c)

supply chain, stocking, and construction processes.[101] However, native voltages remain the same.

Blanket agreements are in place with suppliers to streamline supply chain issues and control costs. For example, a blanket agreement is in place to supply standard recloser controls.[102]

Standard ***bulk*** transformer ratings:[103]

- 115-34.5 kV 62.5 MVA
- 115-12.47 kV 30 MVA
- 34.5-12.47 kV 12.5 MVA
- 34.5-4.16 kV 12.5 MVA
- 115-12.47 kV 30 MVA
- 345-34.5 kV 140 MVA
- 44.8 MVA (outdated standard to be replaced with 62.5 MVA units)

Standard ***non-bulk*** transformer ratings:

- Included in the DSEM manual along with application guidelines.[104]

Eversource purposely avoids deviating from equipment standard designs to prevent expensive "specials." In all cases, IEEE standards are met or exceeded.[105]

Eversource has adopted a relatively new (within the last two years) substation design standard: Installing metal-clad switchgear to the low side of substation transformers.[106] (Use of metal-clad and metal-enclosed switchgear is common in industrial /commercial facilities.) No live bus is exposed when the breaker is opened, offering an important safety feature.[107] Metal-clad switchgear reduces on-site installation/testing costs and engineering time since the breakers, relays, wiring, and metering are all contained in standard cubicles that lend themselves to more modular designs. The T&D Standards group developed a detailed metal-clad switchgear procurement standard (detailed specifications) in conjunction with the Substation Design Engineering group that includes comprehensive requirements and drawings[108] for use within the engineering organization. There was a PSNH perception that metal-clad

[101] Interview #11
[102] Interview #19
[103] Interview #61, Interview #73
[104] DR BPA 4-02, Attachment 1, DSEM Manual, November 2015, Section 14
[105] Interview #73
[106] Interview #73
[107] IR-60, page 4
[108] DR BPA 15-002, Attachment BPA 15-002(a)

switchgear was more expensive than open-air construction, but the perception is changing.[109]

5.17 The supply chain is well integrated. PSNH's Supply Chain organization appropriately changed its normal procurement practices to allow for impacts associated with the international disruption in the materials, services, and contractor availability.

RCG performed a limited review of Eversource's Supply Chain practices as they relate to capital project processes. A supply chain organization is needed to support capital and maintenance requirements. The procurement and store's function must purchase necessary materials and services; store; pre-packages; and issue when needed. Customers, regulators, and shareholders expect a cost-effective and efficient process. Supply chain personnel must manage the inventory and availability of materials and ensure stocking levels are adequate and consistent with capital programs, emergency response, and future demand needs.

Eversource's supply chain personnel are an active partner in the capital project cost-control process.[110] The corporate purchasing function is multi-state and focused on commodity buyers for substation power transformers and major substation components, distribution standard equipment, and standard step transformers. Eversource bids all purchases and services from prequalified strategic vendors referred to as "Contractor or Vendor of Choice". Strategic vendor performance is monitored, evaluated, and fed back regularly through a supplier relationship management program and a third-party vendor risk management program. Purchasing is responsible for initiating and managing warrantee claims against vendors and/or suppliers. Poor contractor/supplier performance will result in their removal as a strategic partner. Purchasing seeks to have multiple sources for either contracted services or vendor-supplied materials. In rare cases where a unique service or material can only be supplied by a single source, senior management approval is required.

Purchasing creates a pre-approved list of contractors/vendors with established rates/pricing. Competitive bidding takes place using the approved Contractor or Vendor of Choice listing. This approach ensures pre-established master services agreements, terms of the contract, etc. are approved upfront so related negotiations do not adversely impact the capital project process.[111]

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[109] Interview #73
[110] Interview #11, Interview #12, and Interview #27
[111] Interview #27

Purchasing is proactively involved in the front-end of capital project development. Purchasing engages with strategic vendor and contractor partners to confirm material and service availability. Additionally, Purchasing seeks input from strategic partners on alternatives to current products and/or services to help identify additional design or solution options.

Purchasing decisions are made based on the "lowest lifetime cost of ownership" and not the initial price, which is a leading industry practice. For example, for power transformers, the lowest cost is a balance between the total cost of ownership, operating cost (losses), and maintenance cost (life-cycle cost). PSNH also looks at the life of the unit, purchase price, delivery, and any additional, value-added services that may be offered by the supplier. This evaluation takes place as part of the commercial and technical review process.

Purchasing has sought out and implemented additional options to expand the availability of distribution transformers, including step transformers. New vendors have been evaluated and selected to provide refurbished and certified transformers. Transformers removed from service are being tested, repaired, and refurbished in-house by the substation testing lab employees, depending on transformer conditions.

Supply disruptions/delays have caused Stores to discontinue the "just-in-time" automated delivery process. Under this former industry standard program, material and equipment inventory levels were kept to a minimum (emergency response levels). Usage, project and maintenance needs, and replenishment delivery times were monitored, adjusted, and ordered electronically. Buyers delt with delivery time updates on an exception basis (reported electronically).

However, since COVID-related supply disruptions, replenishment delivery times have become unpredictable. Purchasing and Stores have responded by putting in place a new process, managed by the Stores personnel, that adjusts inventories based on current needs and material availability/delivery schedules. Now Stores routinely monitors material delivery lead times and recommends purchasing schedules to meet inventory requirements and project schedule and/or routine business material needs. In the case of long lead-time materials, such as power transformers, Purchasing has advanced 2023 purchases. To date, this change has been successful in meeting business needs. There has not been any identifiable impact on PSNH's ability to meet customer needs. In the short run, capital spending should not be impacted since adequate materials and equipment are on hand to satisfy the current year's capital plan. Advanced buying of power transformers has also been included in the current year's capital budget. However, it is still too early to assess the longer-term impact on capital project planning and associated spending.

5.18 PSNH's Stores function operates consistent with industry practices. PSNH's Stores operation practices are consistent with industry practices and a positive contributor to capital project construction schedules, development, and execution.

Stores participates in weekly distribution line schedule and planning meetings. Stores confirm all materials are available prior to a project being scheduled for construction. Additionally, Stores identifies operation's delivery requirements. Stores pre-packages all materials for a project and stage it for operations and/or contractor use. Due to space limitations, they do not pre-load material onto the line trucks. Where project logistics permit, Stores can pre-load materials on trailers or have material delivered directly to construction sites. Since Stores participates in the scheduling process, there have been very few construction delays resulting from material availability issues.

5.19 PSNH makes appropriate use of system planning software. Commercial software tools in use by Eversource are standard industry packages in common use by electric utility companies in the United States. Eversource supplements these software tools with in-house developed/customized software to improve internal operations. Using commercial and in-house developed/customized software tools is consistent with industry best practices.

Appendix B of this report provides a list of Eversource's in-house software. A few examples are mentioned here.

Synergi was selected as the preferred engineering software package for distribution system studies using Python scripts to automate the simulation/analysis process (e.g., load flow, short circuit, harmonics). In addition, Synergi will be used to simulate 10-year, 8760-hour operating scenarios (including DER integration impacts).[112]

The Grid Mod Group is responsible for implementing the transition from the DistriView engineering analysis package (in use in NH) to Synergi (first deployed in PSNH June 2021). The Grid Mod Group is also responsible for in-house software training and first-line user support.[113]

[112] Interview #13
[113] Interview #19

5.20	**PSNH uses compatible units in estimating work. The use of compatible units (CUs) is an industry standard, but the individual units defined for specific work need to be updated regularly to ensure the accuracy of the downstream estimates.**

Compatible Units (CUs) for Maximo are developed and managed by the Standards Group. CUs are state-specific (labor rates, voltages, etc.); however, three-state standards are set whenever possible.[114] It is worth noting that CUs have been an industry-standard practice for several decades. However, in RCG's experience, CUs require significant maintenance, including regular updating, to be an accurate cost-estimating tool (PSNH agrees). Despite the required maintenance, CU is a valuable tool if kept current.

5.21	**NWA screening tools are being incorporated. The in-house NWA screening tool is a step in the right direction.**

Eversource requires system-wide screening of potential NWA solutions against traditional system-upgrade solutions using an in-house developed, Excel-based, NWA Screening Tool to identify viable NWA alternatives suitable for more detailed engineering analysis by System Planning.[115]

An NWA Framework document was also developed that details all assumptions and modeling methods used by the NWA Screening Tool in the screening process.[116]

Eversource's use of the NWA Screening Tool and NWA Framework document are discussed elsewhere in this report.

[114] Interview #11
[115] LCIRP, March 31, 2001, Supplement, Appendix A
[116] Ibid

5.22 Eversource customized a PTX tool. The Eversource-customized PTX tool is appropriate for tracking and evaluating transformer asset conditions and alerts Eversource to emerging power transformer issues.

The customized PTX software tool uses a rule-based expert system to assess transformer conditions using readily available asset condition data and nameplate information that provide insights into the likelihood of failure and associated causes. A *health index* is then calculated based on the following factors: overall condition, operating temperature, electrical condition, core condition, oil quality, and age.[117]

5.23 The Pole Replacement policy has been modified. PSNH's Pole Replacement Program is well documented, managed, and consistent with general industry practices. Given Eversource's annual pole purchases across all three companies, there could be savings due to volume purchasing leverage. Changing the size (diameter) of the pole from class 4 to class 2 is reasonable for PSNH.

The wooden pole has been the standard in the electric utility industry since its inception. Poles' composition, size, class, and height have and continue to be dictated by the pole's application: transmission, distribution, service, or support, and whether it will have other joint uses, such as by the local communications companies and municipalities.

Pole composition can be wood, steel, composition, or concrete. Pole diameter dictates the class of a wood pole. Pole class and height combine to dictate the strength of a wood pole. Typical distribution wood poles used for services and street lighting would be a minimum of Class 6, 30 ft pole. A wooden distribution line pole typically would be sized at a minimum of Class 4 and 35-to-40 ft. However, with the additional height and loading requirements dictated by third parties' joint use of poles, the minimum industry norm for distribution poles has increased to a Class 2, 45-or-50 ft pole. The additional height is to accommodate adequate safety clearances required by all users of the poles.

Which poles "Class" to use is determined by the Standards Group using a pole-loading-analysis program that considers wind and ice to determine the required pole class.[118]

[117] DR BPA 8-004, pages 1-5

[118] DSEM, Reliability Section 02.50, page 02.501, June 2021.

PSNH has a program (consistent with its affiliates at Eversource) of reinforcing its distribution lines to minimize the potential of future outages caused by a combination of tree, wind, and ice damage. This revised thinking is supported by a report produced by TRC, an engineering consulting firm. The study led to several PSNH distribution policy changes, including:

- Moving from Class 4 and 5 poles to stronger Class 2 poles when existing poles are deemed damaged and unsafe; and
- Replacing wooden cross arms with stronger composite cross arms; and
- Upgrading of 12kV and 4kV *pole hardware* to 34.5kV hardware.

The pole policy change was initiated by changing PSNH's long-standing maintenance policy of conducting third-party pole inspections and repairing those with minor ground line rot or replacing them with a new pole of the same class if the existing pole was beyond repair. This inspection and alternative actions practice has been an industry-standard practice for decades. PSNH's new policy affects the latter two options with a required replacement using stronger Class 2 poles, allowing the newer poles to better withstand tree limb impacts (an issue in several recent storms where pole failures occurred.)[119]

Eversource determined that standardizing pole hardware would offer cost savings and improved reliable service in several areas. Eversource reduced the number of items in inventory while improving purchasing leverage by eliminating the variety of similar distribution pole hardware. RCG has learned in recent years that the 4kV line equipment costs were rising due to most distribution line developments focusing on higher voltages, thereby reducing the demand for 4kV equipment. This trend increased the price for 4kV pole hardware. The new Eversource policy includes using 34.5kV insulators and pins on all primary distribution voltage classes and reducing truck and storeroom stocking requirements. This policy change was stated in formal testimony but written in a way that could be interpreted as converting lower primary voltages to 34.5kV voltage, not PSNH's intended position.[120]

Specific to PSNH, the "*TRC System Assessment Report"*[121] commissioned by PSNH in compliance with Section 11.1 of the October 9, 2020, Settlement Agreement in Docket No. DE 19-057 addressed several distribution system reliability criteria and the

[119] Direct Testimony of Joseph A Purington and Lee G LaJoie, DOCKET NO. DE 19-057
[120] Direct Testimony of Joseph A Purington and Lee G LaJoie, DOCKET NO. DE 19-057
[121] May 28, 2021, PSNH Letter Docket No. DE 19-057

standardization of distribution pole applications.[122] The TRC Report's pole recommendations are listed below:

> *"1) Establish a systematic asset replacement program to replace wood poles on an age basis, that support three phase lines, over the next 5 years. Beginning with poles 70 years and older poles, focusing on the smaller class 4 and 5, then address the 60- and 50-year-old poles using the same class criteria. There are about 42,000 wood poles aged 50 years and older that may need to be identified and prioritized for replacement. It is estimated that 20% (8,400) of those poles support three phase lines, requiring approximately 1,700 poles/year of the poles in this age group be replaced in conjunction with the other Company pole replacement efforts.*
>
> *2) TRC recommends poles that are identified as structurally loaded at 90% or greater, be replaced with the correct sized poles to carry the mechanical load under the mandated NESC design conditions. To accomplish this, TRC also recommends that 10% (approx. 4,500) of the overloaded poles, be replaced on an annual basis. Priority should be given to the poles that are overloaded by the greatest amount and/or most critical to the system. It is also essential that all new poles that are installed have pole loading analysis completed to ensure the design criteria is met. Individual pole loading analysis will need Eversource NH Distribution System Assessment 30 to be performed on all angle, tap and dead-end poles. Typical tangent pole analysis can be modeled to promote efficient design.*
>
> *3) Continue the practice to use a minimum of Class 2 wood poles for all applications and ensure that NESC pole loading requirements are met for both the heavy loading and extreme wind scenarios. Based on analysis of the representative data, Class 2 wood poles are half as likely to be overloaded with attachments compared to Class 3 poles."*[123]

RCG's review of pole installations through project reviews and field observations found poles installed for new lines and replacements were consistent with the TRC recommendations. Pole inspection and replacement programs have been an industry-leading practice for decades.

[122] Eversource's TCR System Assessment, pgs. 20-29
[123] Eversource's TRC System Assessment, pgs. 29

Wood poles continue to be the predominant distribution line pole. As such, utilities inspect wooden poles for deterioration from insects, birds, ground line rot, and external damage. Current utility practice is to inspect distribution wood poles independently or in conjunction with a distribution line inspection based on a formal schedule. The inspection schedule varies based on historical inspection results and environmental factors such as climate, soil conditions, and exposure to physical damage. Typically, 10% of a utility's poles are targeted for inspection annually.

The inspection will identify poles that require further investigation, repair, or replacement. Typically, a specialized professional contractor performs analysis, assessing the extent and damage, type, and whether the deterioration can be treated with chemicals for insect infestation, reinforced at the ground line, or patched with an epoxy mixture. These measures are designed to extend the pole's useful life. However, over the past ten years, the public's reaction to environmental impacts from chemically treated poles or chemical treatments of poles, steel reinforcement of poles along roadways, and the effects to the environment from regular access to poles in wetlands has limited application of historical life-extension methods. As a result, more moderately damaged poles are replaced, and the pole material is considered based on environmental concerns (wetlands, storm exposure, ability to guy, etc.). The pole type most considered for such specialized needs are steel poles in difficult-to-access off-road RoWs (both directly buried and in conjunction with a foundation/casing) and concreted poles for storm-prone or high-congestion areas.

Eversource/PSNH recently changed its formal pole inspection and outcome approach for Class 4 and Class 5 wooden poles. If a Class 4 or Class 5 pole is found to have ground-line rot, the pole will be replaced with a new and more resilient Class 2 pole. This departure from industry practice is being done out of concern for the age of installed poles and their ability to withstand adverse weather events. Normally, RCG would have concerns with this change. However, RCG believes the change to be reasonable for the following reasons.

- Many installed Class 4 or Class 5 poles are near or at end-of-life expectancy.[124]
- New Hampshire (like other New England states) experiences periods of significant ice formation, adding weight to the lines and placing additional stress on poles and pole-line hardware.
- Large limbs and tree failures can take down physically compromised poles.
- Many RCG client utilities have standardized on Class 2 poles.

[124] Direct Testimony of Joseph A. Purington and Lee G. LaJoie, DOCKET NO. DE 19-057

PSNH's pole replacement policies and practices require poles to be periodically inspected, with the results dictating subsequent actions. Formal annual pole inspection programs are well defined and documented as described below:

> *"On average, 10% of Eversource owned poles are inspected annually by town location. Non-Eversource-owned poles in the towns identified for pole inspection also receive a visual inspection. Poles are visually inspected based upon age and type of pole preservative. Sound and bore inspections are performed on poles older than those to be visually inspected. The detailed program on Eversource owned poles is summarized in the following excerpt from Eversource's Maintenance Program EMP 5.61 and shown in the Exhibit below:"*[125]

Exhibit 14 - Pole Inspection Criteria[126]

Note 1 = 15 years is the minimum requirement for pole inspection. This interval may be changed due to contractual requirements with joint owners.

Note 2 = The type of inspection performed shall be determined by the age of the pole and its type of treatment, as shown in the following table:

Inspection Type	Creosote, Penta, all others	CCA
Visual	0 to 9 years old	0 to 19 years old
Sound & Bore	10 to 14 years old	20 years old and older
Ground Line Excavate	15 years old and older	If decay is indicated by Sound & Bore

Note 3 = Field supervision shall check the pole within forty eight (48) hours from identification as a "priority reject" to assess the conditions and verify there is no immediate danger to the public. The pole must be made safe within 10 calendar days or less from its identification as a "priority reject" wood pole..

Note 4 = Complete the repair or replacement within one year of determination of need following inspection

As shown in the notes above, pole inspection results fall into three categories: 1) Passed; 2) Normal reject (pole must be replaced within one year), and 3) Priority reject (field supervisor must field-check within 48 hours to ensure no immediate safety concerns). The pole must be made safe within 10 days and replaced within one year.

[125] DR BPA-6-009

[126] DR BPA-6-009. CCA = Chromated Copper Arsenate

The following exhibit shows the targeted and actual pole inspections for the past five years:[127]

Exhibit 15 - Historical Pole Inspection Targets and Actuals

Year	*Target*	*Actual*
2017	*25,493*	*31,873*
2018	*43,816*	*42,399*
2019	*45,666*	*44,097*
2020	*41,319*	*38,477*
2021	*47,914*	*42,897*

Poles that fail inspection are replaced under the PSNH's Reject Pole Replacement Project. Projects are broken down into annual work orders to improve annual budget management and control.[128]

PSNH's Pole Replacement Project results are shown in the exhibit below. Just looking at the most recent rejection rate for 2021 of 42,897 poles, only 136 were rejected, or 0.3 percent of installed poles.

This Reject Pole Replacement Project has funded pole replacements, over the past five years as follows:[129]

Exhibit 16 - Annual Rejected Poles & Replacements

Year	*Reject Count*	*Completed*
2017	270	270
2018	514	514
2019	358	358
2020	165	165
2021	136	136

The above exhibit shows PSNH's commitment to keeping the distribution system safe and resilient. PSNH is keeping up with both the identification and replacement of poles deemed unacceptable.

[127] DR BPA-6-009
[128] Interview #43, Power Plan Panel
[129] DR BPA-7-009

5.24 Steel poles are used judiciously.

Steel poles are a viable solution under specific circumstances. RCG reviewed PSNH's use of steel poles in non-transmission applications. PSNH has recently expanded its use of steel poles beyond transmission structures in RoWs, consistent with the following observations from the TRC report:

> *"… steel distribution poles are an investment that provide a long-term solution for safe, reliable, and cost-effective service to the customer. This investment is one component of improved distribution line resiliency. Steel poles used in off-road right-of-way settings provide additional resiliency benefits to guard against what would be a longer duration outage, given the difficulty in patrolling and replacing these more remote assets in the event of a failure during a severe weather event."*[130]

Additionally, in response to industry environmental concerns for treated wood poles in wet environments and the increasing cost of wood matting to access RoWs, the use of steel poles is specified (excerpts below) by PSNH's policy. RCG did physically inspect one location considered wetlands. The PSNH was required to temporarily install extensive matting, consisting of multiple 8x8 timbers, to protect the wetlands environment from equipment damage during line installation. When matting is temporarily installed, it adds significant expense to the project. The matting cost includes installation, removal, and a rental fee for the time it is installed. PSNH's steel pole policy follows:

> *"New poles installed in Eversource three phase lines in distribution Rights-of-Way are to be direct embedded self-weathering steel poles, class, and height to be determined by the Transmission Line Engineering group.*
>
> *The use of steel poles in other situations, such as for single phase lines, jointly owned facilities, or other special situations, is by exception only and requires approval from managers or above in Operations and Engineering.*
>
> *Steel poles shall not be used for service poles."*[131]

Along with this wooden pole policy change was PSNH's further decision and accompanying policy change to use steel poles for more difficult-access locations in distribution rights-of-way (RoWs). This action minimizes the frequency of bringing large,

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[130] Eversource's TCR System Assessment, p. 38
[131] DR BPA-4-002 Att. 2

heavy line trucks into these difficult off-road locations. Internal to PSNH, some personnel initially misunderstood this policy due to inadequate communications, causing some distribution engineers to misinterpret the directive and use steel poles in locations other than the intended difficult access RoWs. PSNH identified the issue and clarified the instructions to personnel.[132]

RCG believes the expanded use of steel poles is a reasonable policy that will provide the additional benefit of significantly extending the life expectancy of these poles while reducing the frequency of inspections.

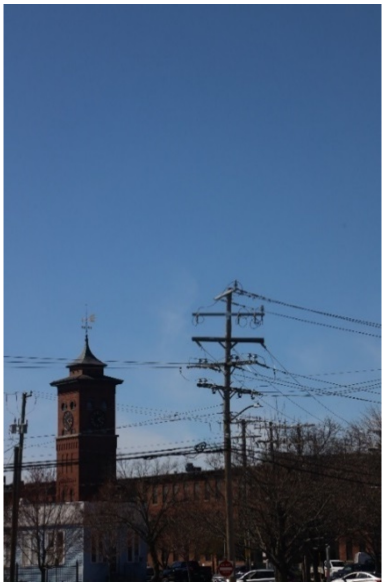
5.25 Capital Project Hours can be more accurately specified. Capital project execution appeared to be appropriate but lacked crew project-hour targets, thereby reducing efficiency target expectations.

While RCG had limited time to evaluate field construction practices, several field crews were visited during the audit process. Crews typically include a non-union working foreman which is unique in the industry, making the foreman accountable for crew quality and productivity. As a result, crews appeared to be well informed on their work assignments.

Electronic work orders did not set time-to-perform expectations but set more macro-level expectations by scheduling 80% of a workweek, leaving 20% to cover unexpected customer needs and/or emergencies. RCG has no issue with this scheduling approach but believes setting specific project completion goals will yield tighter schedule adherence and may allow more work to be completed within the same timeframe.

RCG witnessed PSNH crews responding to a pole hit by a vehicle that took down a single-phase and neutral along a heavily trafficked road. Communication during the clearing and restoration effort was impressive. Crew personnel continually communicated with each other to rapidly clear the roadway and restore power in a safe/timely manner. This suggests crews are well-trained with strong supervision and attention to detail.

[132] Interview #67, Field Visit



The above pictures show some of the typical PSNH Distribution construction and a line crew replacing a pole hit by a third party. As seen in the picture, the crews must navigate the distribution pole installation around the resident tree population. PSNH schedules their crews at 80 percent of the work week on scheduled projects, the remaining 20 percent is for emergency work like what is shown in one of the pictures. An important point is since emergency work is unscheduled the actual work time may take longer than a planned project where all the logistics are planned. As a result, emergency-work wait times for several other reasons beyond the crew's control may include material delivery, public safety, clearances, traffic, etc.

Recommendations

R.5 Develop easy-to-understand examples illustrating the before-and-after impact of *DSPG 2020* system planning criteria changes on system performance (reliability and resiliency) for all PSNH customer classes (residential, commercial, and industrial). The examples also need to clearly illustrate how superseded standards *ED-3002* and *SYSPLAN-010* will be used in conjunction with *DSPG 2020*.

R.6 Develop a formal process to communicate the latest industry activities, including lessons-learned and technology advancements, between departments and potential external parties (other utilities and suppliers).

R.7 Include person hours on all planned project on work orders to support crew performance management.

5.26 System Planning Studies

PSNH's system planning policies, procedures, design guidelines, and processes for evaluating/selecting alternatives (when resolving planning criteria violations) are consistent with industry-standard practices. However, opportunities for improvement exist to address communication/documentation processes to mitigate confusion and misunderstandings when the PSNH interfaces with external entities like the Division.

Planning and designing an electric power system requires ongoing comprehensive analyses to evaluate system performance, determine the effectiveness of expansion alternatives, and identify and, most importantly, proactively resolve problems that might impact system reliability.

System performance projections are created using digital system planning studies based on system performance criteria defined by planning and design criteria/guidelines determined by the standards department that incorporate industry standards and best practices. Issues can be proactively resolved, and alternative solutions can be identified and tested using these digital tools (Appendix B).

As explained in later sections of this report, reliability indices are used to identify worst-performing distribution feeders based on historical outage data and asset condition assessments. System planning studies assess the ability to meet specific design criteria/guidelines. When studied together, solution alternatives can be evaluated, and the best overall alternatives (preferred alternatives) identified.

There is a distinction between a system "plan" and system "planning." A plan is the output of a planning process driven by criteria, policy, and process to develop solutions to problems. Planning is a dynamic process requiring updates to processes and procedures used to create specific plans/solutions.[133] Both "plans" and "planning options" are developed by System Planning.

All transmission and 34.5kV systems are studied using *PSS/E* software and balanced three-phase models.[134] Larger generators are modeled in detail. Load is allocated (not modeled in detail). If a distribution planning project involves the high side (transmission side) of a substation transformer, the Transmission Planning group will

[133] Interview #18
[134] Interview #16

assist Distribution Planning with the study.[135] RCG considers this overall approach to be consistent with industry best practices.

Starting in 2022, Synergi will become the standard software package for modeling the NH distribution system.[136] DistriView had been the standard.[137] Models will be 3-phase (individual phases) instead of the existing single-phase (assumes balanced 3-phase) when fully implemented. The critical point is that detailed load flow modeling is not currently done on 12kV and 4kV systems and will have to be developed, complicating full Synergi implementation.[138]

Distribution Engineering conducts all short circuit and protection coordination studies for everything other than three-phase recloser and relayed circuit breakers done by the Protection & Control (P&C) group using the Aspen OneLiner software package. Single-phase reclosers and TripSaver (electric recloser for cutout applications) coordination studies are conducted by Field Engineering. Even though Synergi has Protection & Control (P&C) capabilities, there are no plans to migrate P&C from the more specialized Aspen OneLiner.[139]

As mentioned above, detailed models of distribution feeders in Synergi do not currently exist.[140] RCG believes System Planning's expertise with the Synergi package can greatly benefit Distribution Engineering when scoping, modeling, and testing new individual phase distribution feeder models. Once these models are completed, full unbalanced phase modeling to the customer meter will be possible, greatly enhancing "what-if" capabilities and better positioning the PSNH to handle DER integration studies.

For substation asset condition issues (inside the fence), Substation & Transmission Engineering alerts System Planning and the seriousness and urgency for resolving the issue. System Planning then develops alternatives from which the best overall solution is selected.[141] Distribution Engineering follows a similar process for asset condition issues outside the substation fence.

PSCAD are transient studies and generally more critical for transmission. *PSCAD* is also used in DER planning to study transients caused by DERs on the distribution system.[142]

[135] Interview #62 and Interview #16
[136] Interview #62
[137] Interview #16
[138] Interview #62
[139] Interview #62
[140] Interview #18
[141] Interview #61
[142] Interview #62

Simulations involving 10-year, 8760-hour data sets create data "nightmares" when managing data integrity. As Eversource is moving toward multi-year time series analysis, the evaluation of simulation results becomes a challenge. To this extent, Eversource is exploring cloud storage solutions. Furthermore, as the simulation models increase in complexity, the requirement for data quality increases. Eversource has showcased this ability in its 10-year study in Cambridge, MA and is working to enable these abilities in all jurisdictions through the Modeling Team.[143] The Grid Mod group is responsible for data verification during the conversion[144] to maintain data integrity. RCG acknowledges the benefits of cloud storage and recognizes other utility companies have successfully used the cloud. However, in so doing, proactive cyber security measures must also be taken to ensure data security and overall system integrity. Lessons learned from the successful East Cambridge implementation should prove to be a valuable resource for this effort.

System studies are based on planning criteria/guidelines specified in the *DSPG* 2020.[145] "What-if" simulations identify potential violations. "What-if" simulations assess potential solutions. For example, PSNH has many substations with two transformers connected on the low side with solid, straight busbars. A disadvantage of this design is that bus faults can trip both transformers. The traditional fix (and accepted industry standard) is to insert a bus-tie breaker. Before/after System Planning conducts simulations to verify the solution. This example represents a typical system study. PSNH has submitted and approved several capital projects with this reliability fix.[146]

PSNH has a number of aging transformers.[147] Age alone is only one of several factors considered by Eversource's PTX transformer assessment tool when calculating a transformer health index.[148] Depending on the system need and associated transformer health index (if transformer adequacy is to be part of the solution), simulations are performed by System Planning to identify feasible solutions to meet the need.

Replacing transformers for capacity reasons is done as a last resort.[149] Alternative solutions include load transfer, NWA (or at least evaluating the possibility), reconfiguration, and combining substations. Sometimes, capacity cannot be met (including backup capacity) without changing or adding a transformer.[150] Potential transformer replacements for asset-condition reasons are summarized in the *2020 Design*

[143] Interview #13
[144] Interview #19
[145] LCIRP, October 1, 2020, Appendix D
[146] Interview #13
[147] Interview #61 and Interview #73
[148] Interview #15
[149] Interview #18
[150] Interview #18

Violations Summary Report for the period 2020-2029.[151] Results indicate very few transformers were replaced solely for health reasons. Results also indicate very few transformers were replaced solely for capacity reasons. (*Note*: Projects proposed in the *2020 Design Violations Summary Report* have yet to be approved by SDC, EPAC, and NH PAC.)

Mobile transformers are available for emergency use, but logistics can be challenging. Transporting and connecting a mobile unit takes 24 hours or more[152] which is too long to have customers without power. As a result, mobile units are typically used for planned outages or to relieve transformer overloads until a more permanent solution can be implemented.[153] (Mobile units are stored in an enclosed area out of the weather at the Mobile Wood facility in Bow, NH, for state-wide use.[154])

Mobile units are often used to restore customer load at non-bulk substations (4.16kV, 12.47kV, or 13.8kV) where alternative supply sources do not exist. The exhibit below summarizes PSNH's available mobile transformer voltages and sizes.[155]

Exhibit 17 - Inventory of Mobile Transformers

Quantity	Nameplate Data		
	Primary Voltage (kV)	Secondary Voltage (kV)	MVA
3	115	34.5	35
1	115	12.47	30
1	46 or 34.5	13.09	14
2	34.4	4.36 or 13.09	10
1	34.4	4.36 or 13.08	7

Mobile units include a high-side disconnection device (e.g., circuit breaker) and a transformer. Cable rails are included to connect the low side if an overhead connection is impossible. The largest units (115-34.5kV 35MVA) require three trailers. The smallest units (34.5-4.16kV, 5MVA) require only one trailer.[156]

[151] DR BPA 1-006, Attachment BPA 1-006, 2020 Design Violations Summary Report – NH Distribution System, revised March 18, 2021
[152] DRs BPA 10-006 and BPA 12-009 1
[153] Interview #18 and Interview #61
[154] Interview #61 and DR BPA 12-009, page 2
[155] DR BPA 10-006
[156] Interview #61

5.27 Proposed bulk and non-bulk substation solutions for all regions (Central, Eastern, Northern, Southern, and Western) appear reasonable and not overdesigned or overbuilt.

RCG reviewed the October 1, 2021, *2020 Design Violations Summary Report – New Hampshire Distribution System Planning*, revised on March 18.[157] The number of proposed capital project bulk and non-bulk transformer replacements by region/area due solely to unhealthy transformers (i.e., no other planning criteria violations) are shown in the exhibit on the following page. All but one replacement required at least one other planning criteria violation before solution alternatives were considered.

Exhibit 18 - 2020 Design Violations Summary Report - Xfmr Replacement Projects

Substation	Existing						Solution				
	Voltage (kV)	MVA	Install Yr	MW Load 2020	# Fdrs	Violation	Voltage (kV)	MVA	MW Load 2029	# Fdrs	Other
Cocheco Street (Dover)	115-34.5kV	TB22 - 44.8 TB55 - 44.8	1972 2001	80.00	4	Unhealthy transformer TB22; N-1 STE violation; N-1 bus fault	115-34.5kV	TBxx - 62.5 TBxx - 62.5	82.00	4	Replace with larger transformers; add series bus tie breakers
Great Bay	115-34.5kV	TB171 - 44.8	2002	45.00	2	N-0 base case load violation	115-34.5kV	TB171 - 44.8	45.00	2	Transfer load to Timber Swamp
Madbury	115-34.5kV	TB65 - 44.8 TB74 - 44.8	1971 1976	70.00	4	Unhealthy transformer TB65; N-1 STE violation; N-1 bus fault	115-34.5kV	TBxx - 62.5 TBxx - 62.5	80.00	5	Replace with larger transformers; add series bus tie breakers; add new feeder
Mill Pond	115-12.47kV	TB171 - 44.8	2014	10.00	4	N-0 base case load violation	115-12.47kV	TB171 - 44.8	13.00	4	Replace transformer at Cutts Street Substation; upgrade distribution lines
Rochester	115-34.5kV	TB53 - 44.8 TB57 - 44.8	1968 2002	60.00	4	N-1 STE violation	115-34.5kV	TB53 - 44.8 TB57 - 44.8	65.00	4	Transfer load to Tasker Farm Substation

The total number of proposed capital projects by region/area in the *2020 Design Violations Summary Report* required to resolve all identified planning criteria violations are summarized in the Exhibit below. DSPG 2020 provides the following guidance for planning criteria:

> *"The planning design criteria are intended to maintain safe, reliable operation of the power system. Projected violations that are not within the planning design criteria are not tolerated. When these criteria are violated, the system must be reinforced, reconfigured, or upgraded to eliminate the constraints by the forecasted violation year."*[158]

[157] All proposed solutions are tentative and subject to further study by System Planning and SDC review; and are based on yet-to-be-approved planning criteria outlined in DSPG 2020 per Attachment BPA 1-006, October 1, 2021, 2020 Design Violations Summary Report – New Hampshire Distribution System Planning, revised March 18, 2021.

[158] LCIRP, October 1, 2020, Appendix D, Section 4.8.2, page 38

The exhibits below (All Projects and Bulk Subs) were tabulated from a detailed spreadsheet developed by RCG from the *Violations Summary Report* included in Appendix A. The Eastern Region bulk-substation-violations section of the detailed spreadsheet was extracted and presented in the Exhibit to serve as an example of what can be found in the detailed spreadsheet for proposed bulk and non-bulk capital projects.

Exhibit 19 - 2020 Design Violations Summary Report - All Projects

Region / Area	ALL Capital Projects Multiple Violations	Region / Area	ALL Capital Projects Multiple Violations
BULK Transformers (115kV and above)		**NON-BULK Transformers (below 115kV)**	
Central	6	SE Corner	7
Eastern	5	SE Center	3
Northern	12	Center	2
Southern	8		
Western	6		
TOTAL	**37**	**TOTAL**	**12**

Exhibit 20 - 2020 Design Violations Summary Report – Bulk Subs – Eastern Region

Region / Area	Capital Projects Due <u>Solely</u> to Unhealthy Transformers	Capital Projects Unhealthy Transformers <u>Plus</u> at Least <u>One</u> Other Violation	Region / Area	Capital Projects Due <u>Solely</u> to Unhealthy Transformers	Capital Projects Unhealthy Transformers <u>Plus</u> at Least <u>One</u> Other Violation
BULK Transformers (115kV and above)			**NON-BULK Transformers (below 115kV)**		
Central	0	3	SE Corner	1	4
Eastern	0	2	SE Center	0	2
Northern	0	6	Center	0	1
Southern	0	2			
Western	0	5			
TOTAL	**0**	**18**	**TOTAL**	**1**	**7**

The substation report summarizes planning violations for each region (bulk) and area (non-bulk) in Appendix A. Details are provided for both "existing" and "solution" system conditions. The "Solutions" column summarizes "preferred alternative solutions" (sometimes referred to as "best overall solution alternative" per earlier definitions). (*Note*: All solutions are based on the *yet-to-be-approved* planning criteria outlined in DSPG 2020[159] and, as a result, are subject to further study by System Planning and a critical review by the SDC.[160]) Project solutions are to collaborate between System Planning, Design Engineering, and Distribution Engineering (for inside-the-fence connections to distribution feeders).[161]

All existing transformers in the above exhibit (Bulk Subs) are 44.8MVA (older units no longer included in the transformer design standards). The new standard specifies 62.5MVA. Based on asset condition assessments and the ability to meet system design needs, strategic plans call for these older units to be systematically replaced. This is the case for Cocheco Street and Madbury Substations. The proposed solution calls for the 44.8MVAs to be replaced with 62.5MVAs to resolve unhealthy transformer issues and multiple (N-1) violations. For both substations, series-tie breakers are proposed to increase reliability and provide load transfer capability options should a transformer fail. Engineering simulations verified all system requirements would be met and planning criteria violations resolved.

At the distribution substation level, Eversource follows accepted industry maintenance and replacement practices of inspecting substations and testing power transformers on a schedule. This policy allows PSNH/Eversource to determine when to replace older, potentially failing transformers consistent with PSNH/Eversource's (and industry) updated asset management policies and procedures. Eversource changed its PSNH policy of power transformer sizes to several specific MVA sizes and voltage ratings to reduce required inventory. This policy shift allows PSNH to order these long-lead-time units without incurring the additional capital expense involved when making a unique procurement on short notice, requiring the Company to "buy in" to the existing manufacturers' transformer production schedule. Having spares of these standard transformers now cover a broader number of installed distribution power transformers and reduces the overall number of spares in inventory.[162]

Another program replaces old oil circuit breakers with newer vacuum breakers, which offer better controls, are environmentally friendly, and are far safer to operate. In the past, there have been industry-wide incidents where the oil breakers have failed and

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[159] LCIRP, October 1, 2020, Appendix D

[160] DR BPA 1-006, Attachment BPA 1-006, *2020 Design Violations Summary Report – New Hampshire Distribution System,* revised March 18, 2021, page 4 of 158

[161] Interview #21

[162] Interview #61 and Interview #73

caused damage. Further, the industry, for decades, has been moving to eliminate hazardous oils that, when spilled, cause ground environmental contamination.[163]

Transformer rewinding/rebuilding is an option to purchase new units depending on transformer condition, time to rebuild, and cost. However, Eversource has not found many circumstances where rewinding is a feasible alternative.[164] RCG understands and agrees with this position.

Environmentally friendly alternatives to mineral oil can be used to retro-fill power transformers and extend useful life. An example is FR3® which is derived from 100% renewable vegetable oils for use in distribution and power generation transformers of all voltage classes. FR3 transformers can operate 15^0C to 20^0C warmer than conventional mineral-oil transformers without sacrificing reliability or life expectancy, allowing for increased load capacity.[165] Eversource has briefly considered the FR3 technology but believes more investigation/evaluation is needed before applicability decisions can be made.[166]

5.28 Eversource routinely implements industry-accepted design practices, following a set of guidelines detailed in DSPG 2020, supplemented by a comprehensive set of documentation maintained in the Engineering Standards Bookshelf. RCG agrees with this process.

One example is installing feeder ties to create multiple sources to improve service reliability and create load-transfer options, making more efficient use of capital. Another is making good use of enhanced checklists in Eversource's enhanced capital review/approval process to improve design quality by focusing attention on engineering and pricing details. However, an area of concern is the low priority PSNH places on integrating DER technologies which could create planning problems down the road if DER penetration rates significantly exceed growth forecasts.

PSNH's distribution voltage classes and corresponding installed miles are given in the exhibit below.[167]

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[163] Interview #61

[164] DR BPA 12-012

[165] IEC 60076-14 Part 14: Liquid-immersed power transformers using high-temperature insulation materials. Edition 1.0. September 2013; IEEE C57.154 Standard for the Design, Testing, and Application of Liquid-Immersed Distribution, Power, and Regulating Transformers Using High-Temperature Insulation Systems and Operating Elevated Temperature. October 30, 2012.

[166] Interview #16

[167] DR BPA 1-025

Exhibit 20 - Miles of Distribution Lines by Type

Voltage Class	Overhead (Miles)	Underground (Miles)	Total (Miles)
4kV	2,733.29	215.43	2,948.72
8.32kV	352.38	36.05	388.43
12.47kV	5,486.63	570.45	6,057.08
13.8kV	8.69	8.36	17.05
34.5kV	3,599.82	1,191.23	4,791.05
Total	**12,180.81**	**2,021.52**	**14,202.33**

System one-line diagrams are of good quality, well-marked with legends, and appear comprehensive, categorized by "*Electric System Control Center*" and "*System Operations Center*." A PSNH map highlights major portions of the distribution system.[168] (A reduced version of this map is included in the Reliability section of this report.)

PSNH's 34.5kV system is 60+ years old and unique to the three-state area (CT, MA, NH).[169] The above exhibit shows 3600 miles of 34.5kV, 5487 miles of 12kV, and 2733 miles of 4kV. Expanding the 34.5kV system where other voltages already exist and satisfy system planning criteria "makes no sense, and it is not done." 34.5kV lines are tapped to meet specific load growth demands, but PSNH has no system-wide plans to upgrade to 34.5kV.[170]

Voltage upgrade decisions (4kV, 12kV, 13.2kV, 34.5kV) are based on the best technical/financial solutions to service the loads. Considerations include the cost-per-saved-customer-minute and the number of customers affected.[171] A case in point is the 4kV system which is reliably operating and meeting the needs. Nashua is an example of where it would cost too much to upgrade the 4kV infrastructure. Currently, the PSNH has no plans to expand/replace the 4kV system.[172]

Another example might be a projected overload of a 4kV substation transformer triggering possible conversion to 12kV. If there is no benefit to converting, the overloaded substation may be retired, and the load transferred to a step transformer. The decision is on the extent to which the substation transformer is forecasted to be overloaded.[173]

[168] DR BPA 1-026 and Confidential Attachments
[169] Interview #11
[170] Interview #13, Interview #16, and Interview #20
[171] DR BPA 7-006
[172] Interview #11, Interview #16, and Interview #20
[173] DR BPA 7-006

Taps taken off 34.5kV lines in RoWs could have one or 1000 customers per circuit. As a result, there is an effort to use distribution automation to create circuit taps or segments that will limit outage exposure to 500-count customer blocks while creating load transfer options. For radial lines, 500-count blocks do not mean only 500 customers will be affected by upstream faults; it simply means the ability now exists to isolate customers into blocks of 500. An important point to make is the following: On a radial circuit with in-line fault protect (breakers), faults occurring closer to the head-end or substation side of the line will affect all customers beyond the point of failure. The radial line must be looped or tied to another independent generation source to overcome this.

Eversource is an industry leader in implementing IEC 61850 technology. The Eddie Substation in NH is the first such T&D installation which serves as an example for future facilities. To keep the focus on substation installations, IEC 61850 will not be applied to the distribution system (reclosers) until some future date is determined.[174]

Bare wire can no longer be installed on distribution circuits unless a phase is added or extended. Covered wire and spacer cable (optional) is used instead but only on a per-case basis, with justification.[175] PSNH believes tree trimming along the distribution backbone is adequate, especially over the last ten (10) years. However, PSNH recognizes vegetation management will continue to be an ongoing challenge. One of the most significant problems is scenic roads, where it is difficult to secure tree-trimming approvals (34.5kV RoWs are maintained by transmission maintenance and construction).[176]

In support of distribution automation, more than 1700 smart devices are installed in PSNH. Currently, there is no peer-to-peer communication between smart devices because PSNH did not want to duplicate DMS (Distribution Management System) communication logic. Instead, data is brought back to a central location for processing. Local device control is still operational.

Looped (backup) feeder-tie connections exist around the system. Multiple ties exist fed from different substations and circuits in the Southern, Central, and Eastern areas. In the Northern and Western regions, there are far fewer looped connections. Even so, there are enough connections to use DA to achieve the 500-customer segmenting target mentioned earlier.[177] DMS will automatically switch ties based on pre-programmed priorities to minimize customers out of service.[178]

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[174] Interview #34

[175] Interview #16

[176] Interview #16

[177] NOTE: projects to loop circuits using feeder-tie connections, and projects designed to achieve 500 customer segmentation are two different efforts.

[178] Interview #19

5.29 The use of greenfield substation sites is discouraged, but when needed, PSNH looks to set a 5-acre minimum land parcel requirement. RCG concurs with this for the reasons stated below.

Minimally sized green-field substation sites may not be large enough to allow mobile-transformer use. RCG believes this to be a good policy. When evaluating substation development solutions, PSNH avoids trying to "fix" substations with significant maintenance issues as cost-saving measures will likely cause more extensive problems and incur additional costs down the road, resulting in unplanned outages that could have been avoided.

If physical space permits, new substations will be built on greenfield sites next to old substations, then switched over to minimize customer downtime. When looking to secure property, PSNH sets a minimum 5-acre requirement, often being able to purchase more land. Eversource considers the incremental cost (e.g., \$150K) to be minimal compared to overall project costs, and the extra space provides a means for building around obstacles (e.g., wetlands), offers multiple orientation design options, provides larger buffer areas from neighbors, and makes future expansion possible.[179]

A typical substation design is the Twombly Street Substation (DR 9-018). The design process uses 3D software to facilitate standardization by using similar designs as starting points, then making modifications as needed. Double-ended substation designs (two transformers) are not standard due to overcapacity versus reliability concerns. This approach is consistent with PSNH's policy of "only doing what is necessary." [180]

There is an external perception that substation overdesigns tend to happen when more than the minimum amount of greenfield land is purchased. Eversource does not believe this to be the case, contending it saves capital dollars in the long run for the reasons explained above.[181] When coupled with the efficient application of metal-clad switchgear (discussed in the Design Standards section of this report), dollar savings can be even more significant.

[179] Interview #73
[180] Interview #61
[181] Interview #61

5.30 PSNH's Protection philosophies and equipment used are consistent with industry-standard practices.

Regarding system protection, the distribution system at the substation level consists of bulk-connected transformers and buses configured with high-speed differential protection. Distribution feeder breakers use time overcurrent protection schemes to coordinate with downline reclosers and fuses.[182] For radial circuits, the fuse closest to the fault opens first. If the fault is between the fuse and the upstream recloser, the recloser operates first. If the fault is between the substation feeder breaker and downstream recloser, the substation feeder breaker operates first. This process is referred to as *selectively coordinated fault protection*. RCG agrees with this approach.

There are no planned changes to this overall approach. However, equipment upgrades are often made as part of asset-replacement capital projects. Examples include replacing electromechanical relays with microprocessor-based devices, adding redundant relaying; replacing fuses with reclosers (e.g., cutout-mounted recloser); and adding high-speed instantaneous or differential protection.[183]

Changes in protection schemes and equipment are also required when DER technologies are applied to distribution feeders to accommodate two-way power flows safely. This DER-related scenario is used on an as-needed basis.

5.31 More data-centric discussions are needed with the Division. Not enough data-centric discussions are being held between PSNH and the Division to demonstrate/explain why the best *overall* solution alternative is not always the least-cost solution alternative.

There are five broad categories of capital projects:

1) Basic business (customer connections);
2) Grid modernization;
3) Equipment obsolescence;
4) Distribution line work; and
5) Distribution substation work.[184]

[182] DR BPA 1-034
[183] DR BPA 1-034
[184] Interview #13

For project development, it is essential to understand the terminology being used by Eversource when presenting solution alternatives. Eversource definitions for each type of alternative follow:[185]

- *Alternative Solutions* – All *reasonable* solutions that address specific identified needs.
- *Feasible Alternative Solutions* – Viable solutions that have no identifiable constraints precluding construction or implementation.
- *Technically Feasible Alternative Solutions* – Viable solutions that have no technical constraints precluding construction or implementation.
- *Least-Cost Alternative Solutions* – Solutions that have the least cost. As outlined in RSA 378:37, it is New Hampshire's energy policy that "least-cost planning" requires the selection of solutions that represent the "*lowest reasonable cost*" based on consideration of factors other than cost, including reliability and diversity of energy sources; to maximize the use of cost-effective energy efficiency and other demand-side resources; and to protect the safety and health of citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.
- *Best Overall Alternative Solutions – Eversource refers to these as "Preferred Alternatives."* Solutions with the best combination of electrical performance, cost, future expandability, and feasibility to comprehensively address all the identified needs in the required timeframe.

Sometimes, "do nothing" is listed as an alternative on the PAF forms. While discouraged, it is an acceptable alternative if a case can be made that more maintenance, increased observation, or operational workarounds can satisfactorily resolve the issues.[186]

5.32 More complete documentation is required for NWA solutions. Not enough attention is given to documenting potential NWA solutions, even though NWA evaluations are integral to the Eversource project selection process. To date, no NWA solutions have been implemented in NH.

Even though progress is being made in developing/applying tools to streamline the NWA evaluation process, more out-of-the-box thinking is required to create feasible alternatives. For example, only two NWA solutions were proposed (Loudon 31W2 and

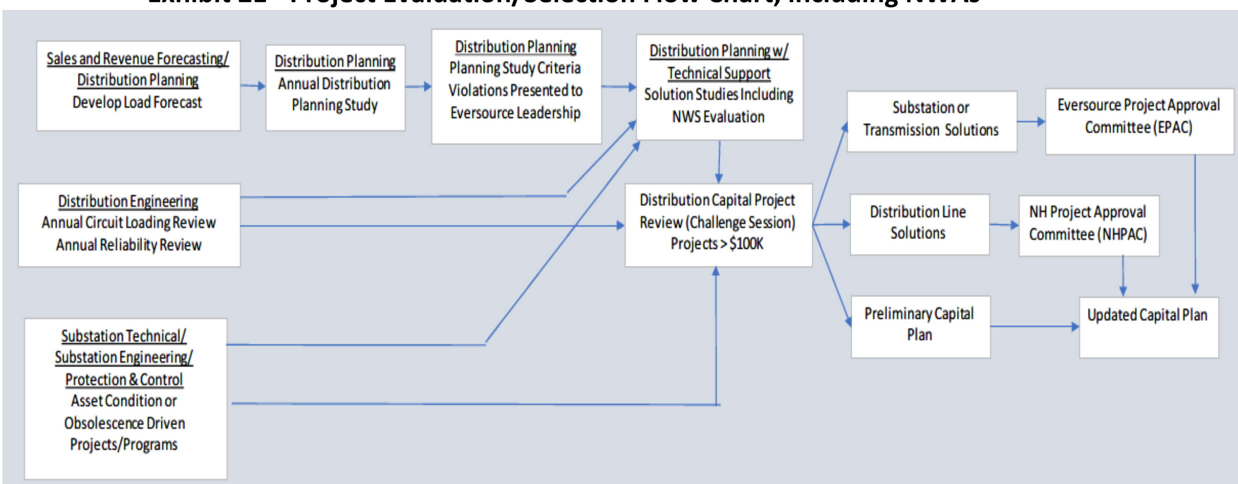
[185] DR BPA 14-007

[186] Interview #34

Hanover Street 16W3, both non-bulk substations) in the *2020 Design Violations Summary Report*[187] out of 37 bulk substation projects and 12 non-bulk substation projects.

The exhibit below provides a high-level flow chart of the project evaluation/selection process for both traditional and NWA solutions. For all substation planning criteria violations, "potentially suitable" NWA solutions must be considered. If a project is a specific size and there is adequate timing (enough time to implement the solution), then NWAs are considered potentially "suitable." NWAs must then pass a revenue requirements impact evaluation to determine which solution will, in the short or long-term, impact customers the least.

Exhibit 21 - Project Evaluation/Selection Flow Chart, including NWAs[188]



Sometimes, NWAs are a sound deferral strategy for more traditional solutions. In the end, a solution must pass a benefit-cost analysis, i.e., the value of the NWA solution divided by the value of the conventional solution must be greater than or equal to 1 for an NWA to pass the benefit-cost analysis threshold. An NWA also has a "fit" criteria, e.g., an NWA is considered not applicable when there is an asset health issue due to failing equipment.[189]

If an NWA does not apply (e.g., equipment failure), it must be noted on the PAF forms.[190] However, this policy/guideline is *not* being consistently followed, another failure in communications. PAF forms do not always include statements regarding potential NWA

[187] DR BPA 1-006, Attachment BPA 1-006 dated 10/01/2021
[188] DR BPA 15-017; LCIRP, March 31, 2021, Supplement, Appendix A, NWA Framework
[189] Interview #18
[190] Interview #62

solutions, good or bad, as was discovered in a May 5, 2021, NH-PAC meeting. An NWA status statement should be included on all distribution line project NH-PAC forms. It can be as simple as, "Due to the immediate need (less than six months) of the project, no NWA investigations were conducted as forth in the rules of the NWA Framework."

The NWA Framework[191] (and NWA Screening Tool) places a value on environmental benefits (e.g., emissions), but these benefits are not rigorously analyzed. In NH, no NWA solution has been approved and implemented. Even though no NWA incentives are currently in place, discussions have been held with some municipalities for potential use.[192]

System Planning developed the NWA screening tool over a six-month period (2019-2020) for all three states to screen NWA alternatives based on cost and technical merits. Factors considered include energy efficiency profiles, CVR, demand-side management, behind-the-meter generators, diesel generators, battery storage, battery storage plus solar, solar, and combined heat & power (CHP). The cost of the traditional and NWA solutions is calculated using the latest approved rate making mechanisms to ensure accurate revenue requirement impacts. Costs are synthesized over a five/six-year period. Results are compared to avoided deferral costs for traditional solutions.[193]

The cost threshold for NWA to be competitive is around $3 M, e.g., a 2MW, 5MWh battery storage installation costs around $5M. PSNH believes going through the motions for anything less does not make sense.[194]

5.33 Conduct in-house training programs for NH hosting capacity map developers and system planning personnel, especially if lessons learned from Eversource CT and MA are included in the training will be productive.

DER hosting capacity maps show the best potential interconnection locations. In MA and CT, hosting capacity maps were developed using Synergi software. In NH, hosting maps do not yet exist[195] but are expected to be released early 2023. When detailed Synergi planning models are completed for NH, individual phase circuit modeling and DER technology models (PV, wind, energy storage) will be possible. More complete what-if studies can then be performed when investigating DER integration capabilities (including the impact of electric vehicle charging stations) and associated system performance

[191] LCIRP, March 31, 2021, Supplement, Appendix A-1
[192] Interview #18
[193] Interview #13
[194] Interview #13.
[195] Interview #13

(including how to safely address two-way power flows), especially when advanced load forecasting algorithms (future scenario modeling) are used.

System Planning is responsible for DER interconnection strategies, including meeting hosting capacity limitations and 2-way power flow constraints (1-way radial now). Protection & Control (P&C) is responsible for DER system protection and associated device settings (e.g., transfer trip, relays). The NH DER integration strategy was initially part of an NH Grid Modernization Program (GMP) not yet approved by the PUC. Integral to the Plan was a systematic conversion of the distribution system to handle two-way power flows from one-way radial designs. The nightmare scenario is if DER penetration quickly increases, significant changes in system design/protection will be needed in a relatively short time to meet hosting capacity and two-way power flow requirements.[196]

5.34 CVR is not being investigated adequately. Consideration should be given to more aggressively investigating and implementing Conservation Voltage Reduction (CVR) for peak demand and energy savings.

Given the relatively high content of residential system load --- 44% of kWh residential sales; 50% of kW residential peak demand. CVR potential in PSNH has *not* been evaluated.

CVR hasn't been incorporated in PSNH but is part of a planned volt-var optimization (VVO) implementation to interface SCADA with DMA with controllable capacitor banks, line voltage regulators, and micro-capacitors (connected to the 240-volt side of distribution transformers).[197]

CVR can reduce peak load demand (kW) and energy use (kWh) by as much as 3%, depending on the system. Opportunities exist on distribution feeders serving loads where normal operating voltages can be reduced without impacting the end-user, e.g., resistive loads, which generally occur for residential loads. Industrial/commercial loads typically contain large motors where voltages cannot be adjusted without impacting the end-user; this results in minimal CVR opportunities. The Exhibit below summarizes the residential versus industrial/commercial make-up for PSNH. *The percent residential load is large enough to justify investigating CVR potential*.

[196] Interview #34
[197] Interview #19

Due to a significant shift in interior residential lighting in NH towards LED lighting (50% in 2020 versus less than 1% in 2009),[198] CVR opportunities may be reduced (LEDs use far less energy). It is further recognized that the load profiles of residential customers in northern NH are different from load profiles in southern NH. Nevertheless, a more in-depth investigation of CVR potential is justified.

CVR is considered an NWA solution and, as such, is included in the NWA screening tool. Eversource's rationale is that CVR is one of the easiest and most cost-effective NWA alternatives for reducing energy use and lowering peak demand. When evaluating energy efficiency, the (N-1) design guidelines no longer apply to CVR or PV behind the meter because the controlling devices are located at different locations.[199]

Exhibit 22 - Residential, Industrial, and Commercial 2020 Load Totals for NH

Customer Class	# Customers 2020	%	kWh Sales 2020	%	Customer Class	kW Coincident Peak Demand 2020	%
Residential	446,612	84.9%	3,373,392,618	43.9%	Residential	864,068	49.8%
Commercial	75,849	14.4%	3,003,670,859	39.1%	Small Commercial/Ind	321,512	18.5%
Manufacturing	2,719	0.5%	1,294,235,314	16.8%	Medium Commercial/Ind	340,270	19.6%
Public Streetlighting	753	0.1%	12,400,749	0.2%	Large Commercial/Ind	207,947	12.0%
Other	12	0.0%	5,880	0.0%			
	-------	------	--------------	------		--------------	------
	525,945	100.0%	7,683,705,420	100.0%		1,733,797	100.0%
	Reference: BPA 15-019		Reference: BPA 15-020			Reference: BPA 15-021	

[198] New Hampshire Residential Baseline Study submitted by Itron to the New Hampshire Evaluation, Measurement, and Verification Working Group, June 11, 2020, pages ES-2 and ES-3
[199] Interview #13

Recommendations

R.8 Develop and test (as a joint effort between System Planning and Distribution Engineering) detailed Synergi feeder models, taking full advantage of System Planning's familiarity with Synergi to facilitate the process.

R.9 Perform an in-depth/rigorous analysis of the data-checking and conversion process for new software platforms (e.g., DistriView to Synergi data sets) independent of the Grid Mod group's conversion verification process to ensure data continuity and integrity are being maintained throughout.

R.10 Develop detailed documentation to maintain data integrity as data conversions are made from one software platform to another, e.g., DistriView to Synergi, Storms to Maximo. This is especially true for Synergi, where individual phase models for distribution circuits are being developed, i.e., converting from 3-phase balanced distribution line models to 1-phase unbalanced distribution line models.

R.11 Investigate the potential benefits of retro-filling power transformers with the latest technology insulating fluids, e.g., extending transformer life (without compromising reliability) and deferring capital investments. Include guidelines for identifying candidate transformers.

R.12 More clearly explain and illustrate with examples why the best overall solution alternatives are not always the least-cost solution alternatives. It is not sufficient to state all criteria violations have been resolved. In addition, consistently document all alternatives considered in the formal project paperwork. Include a formal statement on NWA solution considerations (even if the statement says NWA solutions were not applicable) and reasons why.

R.13 Compare how the traditional solution alternatives are developed and priced against how NWA solution alternatives are developed and priced. Identify areas that disadvantage NWA solutions, e.g., how projected O&M costs are treated. Document key drivers that contribute to cost differences between traditional and NWA solutions.

R.14 Develop and conduct in-house training programs for New Hampshire DER hosting map development engineers. Lessons learned from Eversource CT, and MA should be integral parts of this training.

R.15 Continue to investigate Conservation Voltage Reduction (CVR) potential energy/demand savings for PSNH, given the relatively high content of residential system load --- 44% kWh residential sales; 50% kW residential peak demand.

System Reliability Performance

PSNH's Distribution System consists of 17,600 miles of distribution lines; and 139 substations in a heavily treed state, creating operational challenges to maintain a reliable overhead Distribution system. Recent reliability metrics indicate PSNH's progress in improving system reliability.

Major components of PSNH's electric distribution system are summarized in the following Exhibit:[200]

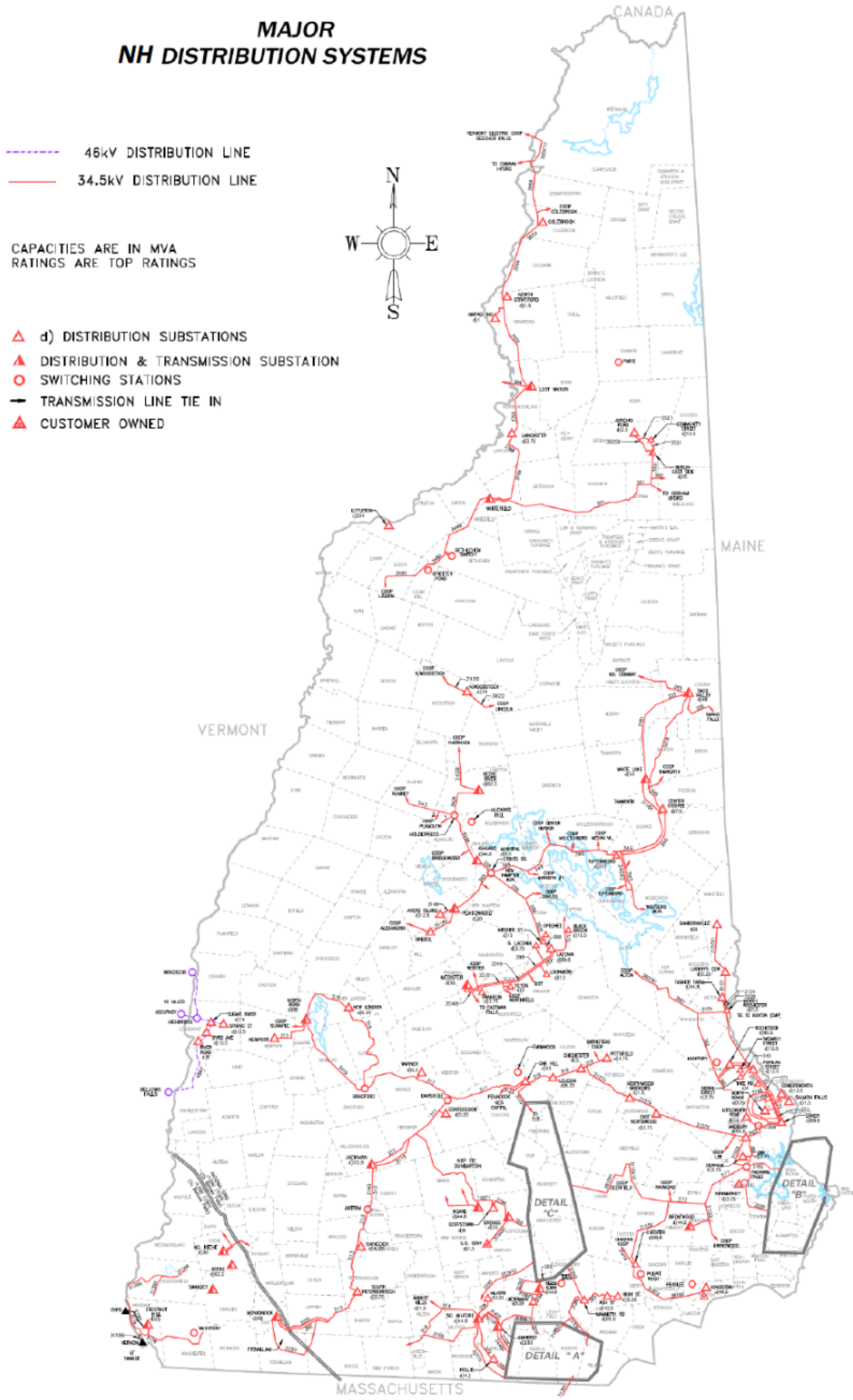
Exhibit 23 - PSNH Distribution System Components

12,200	mi	Overhead Distribution Lines
3,000	mi	Road-Side Distribution Lines
600	mi	Off-Road Distribution Lines
1,800	mi	Underground Distribution Lines
17	%	Distribution Lines - Backbone
83	%	Distribution Lines - OH Lateral Circuits from the Backbone
139		Distribution Substations
184		Substation Transformers (1.5 MVA to 140 MVA)
179,000		Jointly-Owned Poles
276,000		Solely-Owned Poles

The exhibit below shows a state-wide overview map of the distribution system.[201] Red lines signify 34.5kV circuits and dashed lines are 46kV circuits. The map suggests higher load densities in the state's southern portion, especially the southeast region. Also, while not apparent from the map, it should be noted NH is a heavily treed state which creates challenges in constructing and maintaining the overhead portion of the distribution system.

[200] Docket 19-057, Testimony of Joseph A. Purington and Lee G. Lajoie, May 28, 2019, Bates page 397
[201] DR BPA 1-026, Attachment BPA 1-026 C

Exhibit 24 - PSNH Major Distribution Systems Map



RCG RIVER
Consulting Group, Inc.

6.1. Eversource closely monitors reliability performance using industry-recognized reliability metrics. Eversource has proactively identified, prioritized, and implemented distribution automation projects that have consistently resulted in annual reliability performance improvements. Eversource has also defined complementary resiliency program initiatives to maintain and further improve reliability performance.

Distribution reliability falls into the following two categories:[202]

- *Feeder level* - The goal is to minimize both the duration and the frequency of outages due to a fault. The new policy target for customers impacted by a line fault is 500 customers. The desired results are being achieved by segmenting the feeders via switching that started with the Reliability Enhancement Program (REP) using distribution automation to achieve the target.
- *Substation level* - The goal is to develop strategies for load pick-up should a power transformer, or feeder circuit fail. System Planning is responsible for making this happen through substation configuration, bus configuration (e.g., ring bus or breaker-and-half schemes), and equipment selection.

Historical reliability statistics are the quantitative basis for sound decision-making and come in many forms. Overall reliability statistics are excellent for self-evaluation. Utility-to-utility comparisons are made, but differences in each electrical network (weather conditions, number of customers served, customer willingness to pay for reliability, and equipment used) must be considered. While such comparisons have benchmarking value (e.g., utility ranking against its peers), the metrics are most valuable for a single utility system when relative comparisons are examined from period to period (week, month, or year). The data can help make the best decisions considering the utility's system-specific circumstances.

Reliability indices (metrics) indicate system performance and individual circuit conditions, i.e., if the system or circuit reliability improves or worsens over time. Reliability indices are situational and reflect different baselines depending on system-specific designs and operational philosophies. *IEEE Guide for Electric Power Distribution Reliability Indices (Standard 1366*[203]*) facilitates uniformity in distribution service reliability indices and aid in consistent reporting practices related to distribution systems,*

[202] Interview #34
[203] IR-57 IEEE-1366-Reliability-Indices-2-2019 - NGRID

substations, circuits, and defined regions. The standard is universally used (including by Eversource) to characterize distribution system reliability.[204]

In times of extreme events, it may be unreasonable or difficult to track customer outages. As a result, Standard 1366 accounts for major storms separately to assist in tracking severe weather outages (e.g., tornados, thunderstorms, and the like) leading to unusually long outages. In NH, accumulated ice and wind make for significant reliability problems on overhead distribution circuits. A utility can either include planned interruptions/outages (PIs) or keep them separate to measure downtime caused by operations. A utility typically reports reliability metrics with and without storms so that restoration can be a measurable performance objective.

Capital programs require the justification of system improvement projects based on the need to improve overall system reliability and at specific points in the system. To this end, annual system-wide statistics, individual distribution line statistics, and specific components (e.g., transformers, poles, etc.) are collected—annual results aid in determining if reliability improvement initiatives are needed.

Distribution system interruption data and IEEE performance indices can provide data-driven insights when considering reliability improvement measures. Indices most often referenced are the following:

- ***SAIDI*** - System Average Interruption Duration Index (>5 min typically) (CMI ÷ CS) - Number of minutes of interruption average customer experiences.
- ***MAIFI*** - Momentary Average Interruption Frequency Index (<5 min typically) - How often the average customer experiences power quality disturbances.
- ***SAIFI*** - System Average Interruption Frequency Index (SAIDI ÷ CAIDI) (or CI ÷ CS) - How often the average customer experiences an interruption (>5 min).
- ***CAIDI*** - Customer Average Interruption Duration Index (SAIDI ÷ SAIFI) (or CMI ÷ CI) - Average time required to restore service.

[204] IR-58 Understanding Distribution Reliability Metrics

Additional reliability metrics used by Eversource are the following:

- ***COSAIDI***[205] - Contribution to PSNH (system-wide) SAIDI - Used to rank individual circuit performance, considering cost-per-saved-customer minute (primary consideration), number of customers impacted, frequency of interruptions, exposure to lengthy outages due to access issues, and the impact on critical customers.
- ***MBI*** - Months Between Interruptions (months ÷ SAIFI, e.g., 12 ÷ 0.9654 = 12.4 MBI)
- ***CI*** - Customers Interrupted/Impacted
- ***CS*** - Customers Served
- ***CMI*** - Customer Minutes Interrupted
- ***CIII*** - Customers Interrupted per Interruption Index (CI ÷ # events) - This metric is used primarily at the circuit level to help identify the need and location for additional protective devices or automation to reduce the number of customers impacted by a single event.[206]

Important industry norms and definitions follow:[207]

- ***IEEE Criteria*** - Reliability performance without MEDs.
- ***MEDs*** - Major Event Days - Calculated reliability metric based on five years of performance data (including storms and planned & scheduled interruptions), resulting in a daily-SAIDI-threshold-value-per-year. MEDs equate to days exceeding this threshold.
- ***Eversource Reportable Criteria*** - IEEE criteria without planned interruptions. This indicator is the main criterion used within the Eversource organization.
- ***Without*** Storms IEEE Quartile Rankings - This represents the range of reliability metrics respondents experienced during non-major storm days but includes minor storm data.
- ***With*** Storms IEEE Quartile Rankings - It represents the range of reliability metrics respondents experienced during all days. This ranking includes all-in data, MED days, and minor storm data.

205 DR BPA 1-36
206 DR BPA 14-005
207 Id.

6.2. PSNH's reliability performance shows a consistent improvement based on key reliability indices, suggesting system reliability investments are working.

Year-to-year system-wide reliability performance is a vital indicator of the ability to minimize customer outage minutes when expected or higher frequency/probability of occurrence events happen. PSNH's performance over ten years is summarized in the two exhibits presented below based on the following reliability metrics: CI, CMI, SAIDI, CAIDI, SAIFI, and CIII. Both exhibits show a steady, consistent improvement in these indices over ten years (2011 to 2021). (Note: The number of "Parent Events" in the first exhibit represents the sum of the "Parent Events" in the two exhibits that follow.)

Exhibit 25 - NH Reliability Statistics 2011-2021 – ALL Events[208]

Year	# Parent Events	CI	CMI	SAIDI	CAIDI	SAIFI	CIII
2011	14,025	1,420,678	1,121,114,669	2,250	789	2.852	101
2012	11,363	875,435	298,949,392	598	341	1.751	77
2013	10,067	774,073	106,693,930	213	138	1.544	77
2014	11,713	939,411	440,781,256	874	469	1.864	80
2015	8,548	573,772	60,883,395	119	106	1.124	67
2016	11,012	826,837	105,678,322	202	128	1.584	75
2017	16,808	1,018,158	509,073,382	969	500	1.939	61
2018	15,196	1,014,800	207,455,653	392	204	1.920	67
2019	12,013	639,783	122,747,595	231	192	1.204	53
2020	13,761	808,823	249,991,929	467	309	1.512	59
2021	8,883	451,936	82,054,948	152	182	0.839	51

Exhibit 26 - NH Reliability Statistics 2011-2021 – excludes MEDs[209]

Year	# Parent Events	CI	CMI	SAIDI	CAIDI	SAIFI	CIII
2011	8,968	624,920	77,932,762	156	125	1.254	70
2012	9,323	609,069	70,958,452	142	117	1.218	65
2013	8,614	581,827	69,062,920	138	119	1.160	68
2014	9,599	623,637	61,912,845	123	99	1.237	65
2015	8,295	538,776	54,177,931	106	101	1.055	65
2016	9,862	720,704	72,391,329	139	100	1.380	73
2017	11,789	578,995	62,146,242	118	107	1.102	49
2018	10,361	565,301	63,373,060	120	112	1.069	55
2019	8,875	393,465	43,907,584	83	112	0.740	44
2020	8,866	431,001	51,239,298	96	119	0.805	49
2021	6,892	321,961	35,531,699	66	110	0.598	47

[208] Id.

[209] DR BPA 1-35-1, Attachment. MEDs = Major Event Days (Storms)

Exhibit 27 - NH Reliability Statistics 2011-2021 – includes only MEDs[210]

Year	# Parent Events	CI	CMI	SAIDI	CAIDI	SAIFI	CIII
2011	5,057	795,758	1,043,181,907	2,094	1,311	1.597	157
2012	2,040	266,366	227,990,940	456	856	0.533	131
2013	1,453	192,246	37,631,010	75	196	0.383	132
2014	2,114	315,774	378,868,411	752	1,200	0.626	149
2015	253	34,996	6,705,464	13	192	0.069	138
2016	1,150	106,133	33,286,993	64	314	0.203	92
2017	5,019	439,163	446,927,140	851	1,018	0.836	88
2018	4,835	449,499	144,082,593	273	321	0.850	93
2019	3,138	246,318	78,840,011	148	320	0.464	78
2020	4,895	377,822	198,752,631	371	526	0.706	77
2021	1,991	129,975	46,523,249	86	358	0.241	65

6.3. PSNH reliability quartile rankings have consistently improved over the last five years when compared to peer utilities (other northeast utilities), placing PSNH in the 1st and 2nd quartiles. However, reliability performance consistently lags Eversource CT and MA, suggesting there may be room for improvement.

Another key indicator is how well a utility performs compared to its peers. Multiple reliability indices (defined above) are typically used when developing quartile rankings.

The exhibit below summarizes PSNH's reliability performance over five years based on PSNH (ES) reportable criteria (IEEE criteria without planned interruptions and MEDs) representing the range of reliability metrics respondents experienced during non-storm days. The quartile data is based on 17 (varies slightly by year) Northeast and Mid-Atlantic medium-sized companies to provide reasonably comparative data and are based on a three-year historical average of the data; e.g., 2021 quartiles are based on 2018-2020 average data.[211]

PSNH consistently ranked in the 1st and 2nd quartiles against its peers for 2017-2021 (highlighted in green below).[212] Being in the 1st quartile for both SAIDI (system outage minutes) and SAIFI (outage frequency) is excellent and the goal of most utilities. The PSNH believes the interconnected nature of NH substations is key to this reliable performance.[213] For SAIDI and SAIFI, low and decreasing numbers are good. Sometimes,

210 Id.
211 DR BPA 12-013
212 DR BPA 14-005, page 3
213 Interview #18

simply maintaining existing numbers is good enough. RCG agrees with these observations.

Exhibit 28 - PSNH Reportable Criteria[214]

NH - IEEE Criteria - Without IEEE MED Storms

Year	# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	SAIFI	CIII	IEEE Quartiles SAIDI Q1	Q2	Q3	IEEE Quartiles CAIDI Q1	Q2	Q3	IEEE Quartiles SAIFI Q1	Q2	Q3	IEEE Quartiles MBI Q1	Q2	Q3
2017	11,735	581,568	62,285,406	525,227	119	107	1.11	50	108.1	138.1	160.2	98.4	109.5	139.2	1.03	1.13	1.34	11.6	10.6	8.9
2018	10,303	565,301	63,373,060	528,668	120	112	1.07	55	97.1	120.3	148.2	94.8	105.3	125.8	1.01	1.12	1.25	11.9	10.7	9.6
2019	8,821	393,556	43,913,997	531,399	83	112	0.74	45	96.8	116.9	139.0	94.9	103.8	122.5	0.98	1.10	1.21	12.2	10.9	9.9
2020	8,830	431,124	51,247,908	535,095	96	119	0.81	49	81.3	118.5	139.6	94.7	108.2	124.6	0.93	1.06	1.20	12.9	11.3	10.0
2021	9,370	448,477	52,107,413	531,916	98	116	0.84	48	84.8	121.4	149.7	95.3	109.7	129.6	0.92	1.06	1.26	13.0	11.3	9.5

CAIDI (customer outage minutes) performance was not as strong as SAIDI and SAIFI, mainly in the 2nd quartile. When both SAIDI and SAIFI are decreasing (which they are), both the average frequency and the average duration of outages are reduced. However, CAIDI, as the ratio of SAIDI to SAIFI can increase while SAIDI and SAIFI both decrease, if the rate of decrease of SAIDI is lower than the rate of decrease of SAIFI. If reducing CAIDI is an important objective, System Planning can suggest solution alternatives to minimize the occurrence/lengths of these outages.

MBI (months between interruptions) (MBI = months ÷ SAIFI) performance is shown in the Exhibit below.[215] The MBI results for all years place the PSNH in the 1st quartile, which is excellent. For MBI, higher numbers indicate more months between major interruptions, which is consistent with the above CAIDI discussion, i.e., having fewer outages but longer duration.

Exhibit 29 - PSNH Quartile Performance – MBI

NH - ES Reportable Criteria - (IEEE Excl PI) - With Targets

					ES Reportable Actuals/Targets									MBI	Over 12 Months	
					SAIDI		CAIDI		SAIFI	MBI*		CIII	NH - ES Quartiles MBI			
Year	# Parent Events	CI	CMI	Cust Served	Actual	Target	Actual	Target	SAIFI	Actual	Target	CIII	Q1	Q2	Q3
2017	8,949	502,996	56,981,288	525,227	108	104	113	99	0.96	13	11	56	12.0	11.0	9.4
2018	8,164	475,763	56,822,365	528,668	107	107	119	107	0.90	13	12	58	12.5	11.1	9.9
2019	6,033	296,872	36,594,457	531,399	69	102	123	115	0.56	21	14	49	13.2	11.2	10.0
2020	7,455	367,108	45,916,873	535,095	86	95	125	117	0.69	17	15	49	13.9	11.6	10.3
2021	7,615	361,472	45,162,030	539,189	84	93	125	122	0.67	18	16	47	13.8	11.9	9.8

[214] DR BPA 14-005, page 2; DR BPA 12-013, Attachment to BPA 12-013
[215] Id.

When all events (PI[216] & MED) are included (exhibit below), the PSNH ranks in the lower portion of the 3rd quartile for SAIDI, CAIDI, and SAIFI (highlighted in green), i.e., doing worse than many of its peers. However, in 2021, all three indices moved from the 3rd to the 1st quartile. Even though all PSNH indices (SAIDI, CAIDI, and SAIFI) increased over previous years, this shift indicates there were more events and longer-duration events that caused the numbers to increase and that this occurred for all respondents. PSNH's numbers increased less than its peers, causing a quartile shift. Specific details on how this happened require additional investigation.

Exhibit 30 - NH – ES Reportable Criteria – Quartile Performance with PI & MED[217]

NH - With Storms - All-In									All-In Quartiles SAIDI			All-In Quartiles CAIDI			All-In Quartiles SAIFI		
Year	# Parent Events	CI	CMI	Cust Served	SAIDI	CAIDI	SAIFI	CIII	Q1	Q2	Q3	Q1	Q2	Q3	Q1	Q2	Q3
2017	16,436	991,058	488,857,780	525,227	931	493	1.89	60	158.2	238.0	732.0	122.6	199.1	446.2	1.19	1.50	1.85
2018	14,903	990,643	200,596,779	528,668	379	202	1.87	66	123.5	166.8	256.0	109.9	137.5	192.4	1.12	1.25	1.54
2019	11,785	623,614	118,360,911	531,399	223	190	1.17	53	119.8	155.0	217.7	110.5	125.4	157.9	1.08	1.22	1.48
2020	13,485	785,235	240,072,600	535,095	449	306	1.47	58	118.4	149.7	217.9	110.9	132.4	161.7	1.00	1.18	1.46
2021	11,217	562,999	94,270,738	539,189	175	167	1.04	50	143.5	199.7	388.2	120.5	156.8	235.8	1.10	1.31	1.56

Since Eversource sets reliability goals for three states (NH, CT, and MA) (considered peer utilities), it may be appropriate to compare NH targets (performance *expectations*) against CT and MA targets. This exercise can be done by comparing SAIDI, CAIDI, and MBI targets in the exhibit below based on 2017-2021 ES reportable criteria (IEEE excluding Planned Interruptions [Pi's]). (Note: MBI is a key metric used by Eversource.)

Reliability targets are set by Eversource in January for all three states[218] based on the following considerations: historical reliability performance; technology investments, system hardening initiatives; improvements in customer service feeds (i.e., alternate feeds); and improvements in restoration procedures.[219] As seen in the exhibit below, CT and MA targets stayed essentially the same (only minimal change) for 2017 through 2021, suggesting performance expectations were met with existing performance goals; i.e., reliability indices were acceptable as-is.

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[216] PI is an abbreviation for Planned Interruptions.

[217] DR BPA 14-005, page 3; DR BPA 12-013, Attachment to BPA 12-013

[218] DR BPA 8-021

[219] DR BPA 12-010

For PSNH, the targets are set to be more challenging each year, i.e., reduced SAIDI (outage duration) and MBI (months between interruptions) increased. Since MBI is inversely proportional to SAIFI (months ÷ SAIFI), an increasing MBI means SAIFI (frequency of interruptions) decreases. If this trend in setting NH reliability targets continues, NH's targets will eventually meet or surpass CT and MA's.

Exhibit 31 - Reliability Targets for NH, CT, and MA[220]

Year	Location	Measure	Target	Measure	Target	Measure	Target
2017	Electric Field Ops **CT**	SAIDI (ES)	76.45	CAIDI (ES)	105.05	MBI (ES)	16.45
2018	Electric Field Ops **CT**	SAIDI (ES)	77.75	CAIDI (ES)	107.55	MBI (ES)	16.55
2019	Electric Field Ops **CT**	SAIDI (ES)	75.05	CAIDI (ES)	110.05	MBI (ES)	17.55
2020	Electric Field Ops **CT**	SAIDI (ES)	74.75	CAIDI (ES)	112.05	MBI (ES)	17.95
2021	Electric Field Ops **CT**	SAIDI (ES)	73.45	CAIDI (ES)	115.05	MBI (ES)	18.75

Year	Location	Measure	Target	Measure	Target	Measure	Target
2017	Electric Field Ops **MA**	SAIDI (ES)	65.55	CAIDI (ES)	90.05	MBI (ES)	16.45
2018	Electric Field Ops **MA**	SAIDI (ES)	72.05	CAIDI (ES)	99.65	MBI (ES)	16.55
2019	Electric Field Ops **MA**	SAIDI (ES)	68.25	CAIDI (ES)	100.05	MBI (ES)	17.55
2020	Electric Field Ops **MA**	SAIDI (ES)	68.05	CAIDI (ES)	102.05	MBI (ES)	17.95
2021	Electric Field Ops **MA**	SAIDI (ES)	66.45	CAIDI (ES)	104.05	MBI (ES)	18.75

Year	Location	Measure	Target	Measure	Target	Measure	Target
2017	Eversource Electric **NH**	SAIDI (ES)	104.25	CAIDI (ES)	99.05	MBI (ES)	11.35
2018	Eversource Electric **NH**	SAIDI (ES)	107.05	CAIDI (ES)	107.05	MBI (ES)	11.95
2019	Eversource Electric **NH**	SAIDI (ES)	102.25	CAIDI (ES)	115.05	MBI (ES)	13.45
2020	Eversource Electric **NH**	SAIDI (ES)	94.95	CAIDI (ES)	117.05	MBI (ES)	14.75
2021	Eversource Electric **NH**	SAIDI (ES)	92.75	CAIDI (ES)	122.05	MBI (ES)	15.75

Eversource uses monthly scorecards to track performance against targets. Results are distributed to the PSNH Electric Operations management team and included in the monthly Executive Performance Review Package. It is reviewed in the PSNH President's biweekly staff meeting and monthly work plan meetings attended by all PSNH officers, directors, and managers. All reported metrics use the following color codes: Blue (means 10% or more *above* target); Green (means *on* target); Yellow (means *below* target); and Red (means 10% or more *below* target). The portion of the operations scorecard dealing with reliability performance for Jan-Nov 2021 is shown in the exhibit below.[221]

[220] DR BPA 12-010, Attachment to BPA 12-010
[221] DR BPA 8-021

Exhibit 32 - New Hampshire Ops Performance Scorecard Jan-Nov 2021[222]

	Actual	Target		
MBI	19.2	15.5	B	MBI is the 2nd highest in 8 years. Compared to 2020 YTD, minor storms have impacted ~32k fewer customers YTD.
CAIDI	121.1	121.9	G	CAIDI continues to recover following the March storms, in part due to less minor storm activity and non-storm CAIDI being lower.
SAIDI	69.5	86.5	B	SAIDI came in at its second lowest level since 2013. SAIDI YTD is 10.7 minutes lower than 2020 YTD.

SAIDI and MBI are both Blue (10% or more above target), while CAIDI is Green (on target), suggesting that as of November 2021, PSNH was exceeding reliability performance expectations. In 2011 (per an earlier exhibit), SAIDI exceeded 150 min; in November 2021, SAIDI was only 70 min, a significant improvement. CAIDI remains a challenge even though performance against the target is considered good. [The CI metric (customers impacted per event) was shown in an earlier exhibit and has also been downward (i.e. improving) for ten years.[223]]

PSNH understands spending capital dollars on reliability when targets are being met or exceeded is a hard sell. However, reliability is a historical performance metric. PSNH's concern is with issues that could result in significant customer outage minutes. The main issues may be restoration speed and criticality of load, which are most often dealt with at the circuit or substation level. (A standard reliability measure is *worst performing feeders* which will be addressed later in this report.) Resiliency and reliability improvement initiatives are interconnected, i.e., resiliency needs cannot be evaluated or met without first assessing and meeting reliability needs.[224] (Resiliency is mentioned below and will be addressed in a later section of this report.)

6.4. With this level of reliability performance, it is difficult to justify additional capital spending to "improve" reliability. However, when resiliency is considered, future/continued reliability becomes a focus for proposed capital projects.

To understand PSNH's reliability improvement investments, one must understand the Reliability Enhancement Program (REP) initiated as part of the 2006 rate case (Docket No. DE 06-028). REP provided PSNH with additional capital to improve reliability through enhanced capital system programs and equipment upgrades.

[222] DR BPA 8-021
[223] Interview #16
[224] Interview #62

The REP transitioned to REP II in 2010 following PSNH's 2009 rate case completion. While the original program focused on vegetation management, REP II included additional system improvement projects.[225] REP transitioned again in 2015, creating REP3, including everything in REP plus REP II, and adding projects like distribution automation and circuit ties. The REP program was scaled back in 2018 and ended in 2019.[226]

While not identified as REP, REP reliability/resiliency programs are embedded in today's capital budget program. Example projects/programs include the following:[227]

- Distribution Automation Program,
- TripSaver Program,
- Line Sensor Program,
- Circuit Ties Program,
- Direct Buried Cable Replacement Program,
- Pole Inspection Program,
- Oil Circuit Breaker (OCB) Replacement Program,
- Capacitor Switch Replacement Program,
- PLC Automation Scheme Replacement Program,
- Electromechanical Relay Replacement Program,
- Substation Animal Protection Equipment Program, and
- RoWs Hardening/Reconductoring Program.

Each program is considered a project requiring a PAF and associated justification. Each project is evaluated and authorized annually before being included in the approved capital budget. A core tenet of Eversource is to adhere to the approved yearly capital spend limit, which forces management to prioritize capital projects for any given year.

6.5. PSNH's most significant asset-related condition assessment issues involve power transformers, PCB-containing equipment (transformers, circuit breakers, bushings), and animal protection. In each case, systematic replacement plans are implemented consistent with capital budget constraints. RCG agrees with this approach.

Asset management deals with two types of aging: First, due to years in service; and second, due to loading. For transformers, the EPRI-based PTX tool addresses both

[225] DR BPA 3-3, Table on page 2
[226] DR BPA 3-3
[227] DR BPA 4-15

types of aging along with other factors to determine the optimal replacement schedule. (See this report's System Planning Criteria-Technical Standards/Guidelines section for more on the PTX tool.) Storm conditions can ultimately be the last straw to failure.

The goal is to extend transformer life as much as reasonably practical through regular maintenance programs and major overhauls while anticipating the conditions for potential transformer failure before a storm hits. Maintenance could involve rebuilding a transformer as a cost-saving measure over buying new ones. However, rebuilds are often not viable solutions due to conditions or cost constraints.

PSNH has more than 80 power (bulk) transformers that are 50+ years old. They believe these older transformers cannot be replaced fast enough to stay out of the high-risk category. So, as a precautionary measure, spare transformers are maintained in the" warm" state for the different voltage classes and strategically located by region in each state.[228] Concurrently, PSNH management recently decided to standardize on four power transformers (62.5MVA, 30MVA, 12.5MVA, and 140MVA) to meet system requirements while reducing the number of spares. RCG believes this to be a sound approach.

Environmental concerns must also be addressed. One of the more significant environmental issues involves replacing PCB equipment with non-PCB equipment. Regulatory requirements for PCB use and disposal must be considered, as well as the financial risks if PCBs are released into the environment. Timely replacement/disposal of PCB-containing dielectrics is key to preventing future expensive liabilities.[229] The most significant source of PCBs is U-type bushings used to connect power transformers. Another source is oil circuit breakers used to connect the transformers to lines and buses. These components are usually replaced as part of a substation rebuild project.[230] For Eversource, PCB replacement program strategies are developed by the Director of Quality Assurance T&D.[231]

Another potential risk is aggressive animal behavior, requiring more sophisticated animal protection. Ravens have been an "unbelievable problem in vandalizing substations," according to one of the interviewees.[232] Even though animal protection had been installed per industry standards, the ravens found a way to bypass the protection. After meeting with utilities dealing with similar animal issues, Eversource decided to install lasers as the most promising way to alleviate the problem. Time will tell if more

[228] Interview #21 and Interview #16
[229] Bench, Dan. "Identification, Management, and Proper Disposal of PCB-Containing Electrical Equipment used in Mines." Page 10 of 11, date unknown but estimated to be early 2000's.
[230] Interview #61
[231] Interview #61
[232] Interview #61

actions are needed. RCG believes this approach to problem-solving is consistent with industry best practices.

6.6. PSNH appears to be following current standard industry practices when identifying and resolving power quality issues (primarily voltage related).

Customer power quality (PQ) expectations are high, driven by more home offices and sophisticated and temperamental electronics. Industrial and commercial customers demand the same and, in some cases, higher levels of power quality. Voltage complaints are monitored, and not many are received in NH.[233] Some customers classify momentary interruptions (<5 min) as PQ problems even though PQ refers to perceptible voltage and current fluctuations, which can adversely impact electronic equipment.

Per DSPG 2020, System Planning is addressing the following power quality issues:[234]

- Steady-state thermal and voltage criteria guidelines,
- DER impact on voltages,
- Voltage flicker issues,
- Transformer reverse power capabilities, and
- Unbalanced voltage (3V0) for high impedance ground fault issues.

6.7. Worst performing feeders are monitored and ranked on an annual basis. Some feeders are classified as the worst performers year after year due partly to two major North-South 34.5 kV lines not being looped (creating alternate feeds). When faults occur on these circuits, all customers downstream of the faults will experience an outage.

Utilities continually develop and maintain a list of worst-performing feeders annually based on a consistent reliability performance metric. Eversource uses COSAIDI [Contribution to PSNH (system wide) SAIDI], which weights radial circuits with large customer counts more heavily than other circuits. As a result, the same circuits can appear on the worst-performing circuits list year after year.[235] For example, a 150-mile circuit

[233] Interview #11
[234] LCIRP, October 1, 2020, Appendix D, page 9
[235] DR BPA 1-36, Attachment to BPA 1-36

with 8000 customers will have more exposure than a 75-mile circuit. Some circuits have been in the top 10 for a decade.[236]

Efforts are underway to apply SCADA-controlled pole-top devices (e.g., reclosers) to break distribution lines into customer blocks of 500 customers or less (discussed earlier in this report). This cost-effective program can improve a worst-performing circuit and prevent a circuit from making the list.[237] However, the best solution is to find locations where alternate feeds can be feasibly constructed for long radial circuits, i.e., create circuit loops with alternate feeds, not just segment lines into customer groups. Looping is often not feasible due to cost or physical constraints. In these cases, localized NWA solution options should be considered.

PSNH is willing to accept higher costs-per-saved-customer-minutes for projects that benefit large numbers of customers.[238] Unfortunately, this runs counter to the goal of "treating all customers equally" since customers at the end of radial circuits will always be impacted by upstream faults, i.e., these customers will be continually disadvantaged because of where they live. Recognizing radial circuits can be challenging to manage, RCG believes every reasonable attempt should be made to minimize the disparity. As PSNH continues to loop more of the remaining radial circuits, this problem will continue to dissipate.

PSNH evaluates each circuit, determines where reasonable, cost-effective solutions can be applied and includes them in the capital plan. However, the ten worst-performing feeders do not automatically appear on the plan but must be evaluated and prioritized along with all other proposed projects. As a result, PSNH does not proactively develop a worst-performing-feeder-improvements project schedule since it must compete with all other system needs during each budget cycle. In addition, the list of worst-performing circuits is based on a single year's performance, meaning new circuits and potentially more cost-effective projects will be proposed and reviewed each year.[239]

[236] Interview #16
[237] DR BPA 1-36
[238] DR BPA 1-36
[239] Id.

6.8.	**Resiliency is another cornerstone to building a reliable distribution system. Given PSNH's heavily treed/ice environment, RCG believes PSNH is pursuing a reasonable course of action by looking for systematic opportunities to improve at-risk circuits and substations incrementally. Investing in resiliency programs to preserve reliable performance and meet customer expectations is consistent with industry-standard practices.**

Reliability and resiliency are often mistakenly used interchangeably. However, they are different. *Reliability* is most simply defined as the power is either ON or OFF. IEEE summarizes the more commonly applied industry definitions (from NERC, US DOE, IEEE, and NATF) in Technical Report PES-TR83.[240] In this report, US DOE defines reliability as "the ability of the system to deliver expected service through both planned and unplanned events."

For *Resiliency*, there is no universally acceptable industry definition despite attempts by organizations worldwide to do so. PJM (Pennsylvania-New-Jersey-Maryland) Interconnection came up with the following simplistic definition for resiliency: "It is about the power system's ability to withstand extreme or prolonged events."[241] The author goes on to say, "You cannot be resilient if you are not first reliable." Reliability is the historical performance of a system or circuit, while resiliency is the future performance of a system or circuit under potentially extreme conditions. The industry currently categorizes resiliency projects into (a) mitigation, (b) preparedness, (c) response, and (d) recovery.[242]

Eversource defines *Reliability* as the ability of the electric power system to deliver electricity to the end-user.[243] When evaluating reliability performance, Eversource applies standard industry-accepted reliability metrics (SAIDI, SAIFI, CAIDI) discussed elsewhere in this report.

Eversource defines *Resiliency* as "the ability (of) the electric power system to withstand and recover from low probability, high impact, extreme and damaging conditions, including weather and other natural causes."[244] Or, put another way, the ability

[240] IEEE Power & Energy Society Industry Technical Support Leadership Committee Task Force. "Resilience Framework, Methods, and Metrics for the Electricity Sector," Technical Report PES-TR83, October 2020.

[241] Ott, Andy (President and CEO). "Reliability and Resilience: Different Concepts, Common Goals," PJM Inside Lines, December 17, 2018.

[242] IEEE Power & Energy Society Industry Technical Support Leadership Committee Task Force. "Resilience Framework, Methods, and Metrics for the Electricity Sector," Technical Report PES-TR83, October 2020.

[243] DR BPA 14-006

[244] *Id.*

to withstand a storm and other significant events, and recover from them in a reasonable amount of time.[245]

While Eversource does not have a formal documented process for triggering resiliency projects,[246] resiliency initiatives have been set as follows:[247]

- Tree Trimming
- Electrical Hardening
- Structural Hardening
- Equipment Automation

When the industry evaluates reliability performance and calculates metrics, it is usually done with and without major events. Major events are excluded to focus on the day-to-day performance of the system. Major events, typically weather-related, have a low probability of occurring, but they can have significant ramifications. Electric utilities must prepare the system for such events and have active plans to respond. Although PSNH ranks in the 1st and 2nd reliability quartiles excluding major events (see Reliability section), that PSNH only ranks in the lower portion of the 3rd reliability quartile when major events are included[248] suggests there are potential opportunities for improving resiliency to reduce the impact of storms and improve restoration capabilities post-storm, especially when considering the observable increase in frequency/intensity of storms in New England.[249] (While not part of this business process review, RCG believes it would be advantageous for PSNH to review/update its emergency response plans.)

Examples of resiliency-based capital projects initiated by PSNH include the following:

- Upgrading distribution poles, shown to have ground line rot issues, to stronger class 2 wood poles or more resilient steel poles in areas of difficult access;
- Replacing cross arms with composite ones;
- Reconductoring to more resilient conductors such as covered wire and spacer cable in areas where tree damage is more prone; and
- Installing distribution automation (automated switching) to reduce the impact of customer outages by isolating faulted feeder sections.

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[245] Interview #16

[246] DR BPA 9-019

[247] Eversource. "Improving Electric Reliability: Eversource's System Resiliency Program," www.eversource.com

[248] DR BPA 7-007, Attachment pages 10-12

[249] DR BPA 14-006

The question always is, "When is reliability/resiliency good enough?" Or, put another way, how can capital funds be best allocated to meet reliability targets and satisfy resiliency goals? Some in PSNH contend resiliency has not been a problem;[250] others say improvements are needed.[251] The ultimate answer lies in which projects get approved. Today's submittals must follow the latest Eversource capital-approval process, including technical and cost justification components. The more compelling the case, the more likely the approval. Distribution Engineering collaborates with System Resiliency & Reliability group to identify potential resiliency projects.[252]

PSNH's core capital distribution investments are primarily in overhead equipment and facility upgrades to make the system more resilient to major events while preparing a platform for integrating advanced technologies (e.g., DER) at virtually any point on the system, including the ability to accommodate two-way power flows on distribution lines.[253]

Since conditions change yearly, the assumption that "reliability is good enough" is not acceptable. There will always be risks and corresponding needs for corrective actions. Investments in resiliency measures are needed to prevent/minimize catastrophic events. PSNH looks to the industry for guidance on how far to go and when to stop.[254] Two important PSNH system characteristics are the significant number of trees present and the system's high probability of ice buildup on the lines, which places PSNH in a high risk position.

PSNH believes investments in reliability and resiliency are necessary to remain in the 1st quartile (preferably) or 2nd quartile (at worst) peer reliability performance categories.[255] The nightmare scenario is an ice storm with the wind causing tremendous damage from falling trees and bringing down power lines and poles. When protective devices (switches) try to operate to clear faults, the devices cannot because contacts are frozen shut. Worse yet, feeds from either end may be cut off by system faults. There is a need to protect against 60-70 mile/hour winds which seem to be occurring more frequently.[256] Ice, ice loading, and wind are ongoing concerns, even for well-trimmed RoWs.[257] For these reasons, PSNH has placed a high priority on reliability- and resiliency-related investments.

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[250] Interview #61
[251] Interview #16 and DR BPA 7-007
[252] DR BPA 9-019
[253] DR BPA 1-005
[254] Interview #11
[255] Interview #16
[256] Interview #16
[257] Interview #11

PSNH believes operations does a very good job of maintaining substation equipment. However, there is a concern (this has not happened yet) that failure events will start to increase due to aging infrastructure. For example, several 62.5MVA and 44.5 MVA transformers are 50+ years old.[258] The oldest 140MVA transformer is 36+ years old. In response to these concerns, PSNH is taking measures to quantify and prioritize actions using the EPRI-based PTX transformer assessment tool (discussed in earlier sections of this report).

A substation reliability program in process for several years is the oil circuit breaker (OCB) replacement program, which focuses on replacing aging and PCB-containing equipment. If a substation OCB fails, many customers can be affected. If the OCB contains PCBs, potentially significant environmental cleanup will be required.[259]

PSNH believes the biggest obstacle for reliability-based projects is getting them scoped, engineered, approved, and included in the capital plan. Three active distribution substation projects (White Lake, Dover, and Monadnock); and seventeen (17) additional distribution substation projects were identified in the *2020-2029 Load Flow Study* as having (N-1) contingency violations (based on the DSPG revised planning criteria).[260] 14 of the 17 projects were due to STE (Short Term Emergency) rating violations, bus faults, bus-tie breaker issues, and single-contingency transmission issues (causing a double-contingency condition on the distribution system). (Refer to Appendix A for a complete list of projects and respective violation summaries.)

These 20 substation projects total $225 M based on conceptual engineering estimates. PSNH believes all 20 are needed. However, that would exceed the annual capital budget. According to PSNH, "The challenge (then) becomes prioritizing and spreading them over a reasonable period of budget cycles to get them all done prudently."[261] The updated capital approval process is expected to facilitate this process.

PSNH determined NH's pole inspection program meets today's needs but is concerned about future resiliency needs. 35% of the pole population is 40+ years old. The concern centers around what the former inspection program did not do, proactively replacing the oldest poles. The inspection program looks for imminent replacement needs (<10 years). PSNH believes better pole integrity/replacement metrics are needed from an asset management perspective, which is the position taken in recent rate cases.[262]

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[258] Interview #61
[259] Interview #61
[260] Interview #62
[261] Interview #62
[262] Interview #11

Customer expectations are changing, and according to one interviewee, "We don't want to fail 400-4,000 poles in the same storm." Add to that the changing nature of weather and the concern is magnified. Customers could be out for eight or more days in worst-case scenarios. PSNH believes the pole replacement target should be closer to 1,000 poles/year rather than the relatively small number done today. PSNH believes replacing poles in clusters rather than one at a time is the most cost-effective approach from a resiliency point of view.[263]

PSNH does not believe a resiliency program can be based on the following position: "In the last five years, we have not had a storm that resulted in more than a two-day outage for customers." Customers, regulators, and politicians are not going to accept two-day outages. So, resiliency is essential in meeting and maintaining reliability expectations.[264]

Recommendations

R.16 Conduct a protection and coordination study in conjunction with System Planning at the distribution circuit level to better understand and anticipate how 2-way power flows can be safely accommodated.

R.17 Take more aggressive actions to correct chronic problem feeders by implementing one or more of the following:

- **Reduce COSAIDI or other reliability targets to encourage more aggressive distribution automation and sectionalizing schemes; and**
- **Find locations where alternate feeds can be feasibly constructed for long radial circuits, i.e., create circuit loops, not just segmented customer groups; and**
- **Apply localized NWA solution options, where suitable, when looping feeders is not a feasible alternative and the solution exceeds NWA thresholds. Subsequent revisions to the NWA Framework may be required.**

[263] Interview #11
[264] Interview #62

Third-Party Claims

7.1. Within the external constraints of third-party damage recovery, PSNH has a reasonable process to track and recover the costs associated with third-party damages to the distribution system and transfer the net costs into ratebase. However, the process is not fully documented in writing which could create opportunities for varying interpretations of how to execute the process and any decisions required.

In RCG's experience, when a third-party entity damages a typical utility's property (generally already included in ratebase) the utility must repair or replace the damaged equipment to ensure reliable and safe service. As the damage is unpredictable, the financial impact can vary from period to period. All or a portion of the capital expenditure (and maintenance expenses) may be offset by recoveries from the responsible party causing the damage or the responsible party's insurance coverage.

A typical utility estimates an annual amount for capital expenditures within its capital budgeting process. That amount is reconciled to the actual cost of repairing the damage less the recovery of those costs from the responsible party causing the damage. The costs of repairs would typically enter ratebase (less the recovered costs) during a rate case or tracker mechanism as authorized by the regulatory scheme.

During PSNH's request for its first step adjustment pursuant to the settlement reached in Docket DE 19-057, treatment of its post-rate decision capital costs prompted questions from the Division over how PSNH accounted for the capital costs and the associated recovered costs. At that time, PUC Staff (now the Division) conducted an audit of the initial 2019 Step adjustment, and the audit report was submitted at the time of the second step adjustment (2020) filing and third-party claims became an issue in that proceeding. Cross-examination covering the issue took place, and the Commission decided to include the issue within the Business CapEx Process Audit.

> *"Eversource discussed its treatment of costs related to replacing plant in service when a third-party damages utility property. Eversource explained that once the Company knows that the damage was caused by a third party, and the third party is identified as responsible for payment, the Company will bill the individual or insurance company for the damages. Once Eversource generates the bill for damages, Eversource credits the work order within the annual project in the calendar year that the Company actually bills the third party. Eversource argued that it would be inappropriate to assume recovery of damaged plant is a given and stated*

that this topic should be addressed during its upcoming business process audit."[265]

The Division audit (February 1, 2021) states, "To date, PSNH has not responded sufficiently. Audit Issue #1"" PSNH included $1,789,400 in the current 2019 Step adjustment. This figure does not account for the anticipated contributions of $(1,189,200)." [266]

The Division audit process includes two opportunities to potentially resolve differences through the discovery process and the comment period provided to the utilities. As a result, drafts and input were exchanged between the Division auditors and PSNH. The audit was issued, and PSNH provided comments.[267] According to PSNH, there was limited discussion. The Division audit group concluded that it could not confirm or trace the expected reimbursement offset based on its review of PSNH's filings.[268] The Division's audit report was entered into the case as an exhibit in the 2020 Step adjustment hearings by the Division with the subsequent cross-examination of PSNH on the issue.[269]

7.2. Third-party damage presents PSNH with some unique challenges as the incidence and timing of damage are beyond the PSNH's control.

While third-party damages are a small part of PSNH's annual capital expenditures, all, or some portion of those expenditures (the amount not reimbursed by the responsible party or its insurance coverage) will eventually enter ratebase and become a cost of doing business and thus increase rates paid by customers.

Unlike standard PSNH-initiated capital projects, third-party damage is not initiated by PSNH, and the work scope and timing are only under PSNH's limited control. While the total capital amounts are accumulated into a budgetary line item, they consist of many independent incidents. The exhibit below indicates the number of incidents.

[265] Order No. 26,504 Page 3
[266] DR BPA 5-004, Attachment Page 3
[267] Claims Panel #1
[268] DR BPA 5-004, Attachment Page 5
[269] Claims Panel #1

Exhibit 33 - Annual Number of Events and the Number of Identified Offenders

Year[270]	Number of Incidents[271]	Total Costs Before Recovery[272]	Responsible Party Identified[273]
2017	1,197	$ 2,172,199	515
2018	1,421	$ 2,560,753	594
2019	1,584	$ 2,467,492	640
2020	1,231	$ 2,929,850	448
2021	1,308	$ 3,106,301	478

Typically, PSNH is notified of damage to its facilities by the police as they respond to and investigate an accident. In other incidents, third-party damage may be caused by a contractor damaging PSNH's facilities that require a response by PSNH. During routine inspections of PSNH's facilities, third-party damage may be detected.

7.3. PSNH's responders immediately document the site in written form, photographs of the site and identification of the responsible party (if available); together create a formal record of the event.

Depending on how the incident is reported and the severity of the damage, the initial work and investigation are performed by a Response Specialist[274] or a line crew.[275] PSNH on-site responders may take a photo of the responsible party's license plate at the scene.[276] That information is embedded within the electronic record of the work order.[277]

Reimbursement for third-party damages can take a substantial effort and take significant time to resolve. PSNH's collection for third-party damages is hampered by the state of New Hampshire's not requiring mandatory auto liability insurance, the responsible party's ability to pay compared to the cost to collect, the availability of police reports, and unreported (hit and run) incidents. However, the collection is aided by the NH DMV license suspension process.

[270] Incidents and amounts may be out of synch due to date of recording the various aspects of the incident.
[271] DR BPA 8-013
[272] DR BPA 5-003
[273] DR BPA 8-013
[274] Interview #71 and Claims Panel #1
[275] Interview #72
[276] Claims Panel #1
[277] Claims Panel #1

7.4. While PSNH has a process for discovering, tracking claims,[278] and accounting for the costs of third-party damages, that process is not formally memorialized in a written policy that spans the entire process.

PSNH does not have a detailed flowchart or process document for the entire third-party claims process[279]. Although PSNH provided a narrative in response to a data request[280] the third-party process is not recognized in a distinct Sarbanes Oxley (SOX) accounting process, rather controls fall within separate functional areas.[281]

Conceptually there are three types of major damage claims. (The "Type" designation has been created by RCG solely for clarity.)

- Type 1 – The responsible party cannot be identified (hit and run event).[282] *No potential offset of costs is expected.*
- Type 2 – The responsible party is identified and has liability insurance. *Reasonable expectation of payment:*
  - Payment may not be for the amount originally billed due to insurance negotiations related to the asset's depreciated cost.[283]
- Type 3 – The responsible party is identified but has no insurance. *Extended time to receive payment (if any) due to*:
  - Payment plans,
  - No assets,
  - Costs of recovery (legal fees) are expected to exceed repair costs, and
  - The final payment status (none or partial) may take years depending on the processes involved. [284]

Due to the timing of the repair compared to the eventual recovery of none, all, or a portion of the costs from the responsible party, a reconciliation process is needed to recognize and confirm accounting for the actual payment level compared to the amount billed to the entity.

[278] DR BPA 16-001
[279] Claims Panel #1
[280] DR BPA 5-005 and Claims Panel #1
[281] Claims Panel #1 1:34:09
[282] DR BPA 8-013 and Claims Panel #1
[283] Claims Panel #1
[284] Claims Panel #1

7.5. The Administrators, who are the designated employees responsible for capturing, validating, and monitoring the costs of third-party damage, appear to be functioning well and are appropriately managed.

RCG interviewed two Administrators (a position located at the regional operating centers) who described PSNH's process to determine if an incident has occurred and then create a claim. Daily, the Administrators monitor activity such as trouble reports from the outage-reporting system to find incidents. The priority of this monitoring is considered second only to payroll. The Administrator will create an individual work order for each incident.[285] The initial preparation of the claim is handled by an Administrator[286] at the local operating center. The work order contains backup information including incident photos.[287] The costs of the incident are retrieved from PSNH work order records and time reporting. Some inherent time delays are attributed to all until other costs are entered into the work order, such as environmental response contractor and material costs.[288]

The Administrator will search for the responsible party within the records entered by the PSNH responder. The Administrator will use the Lexis-Nexis document database and if necessary, make personal contact with local police to obtain a police report.[289] The identification of the responsible party may be difficult as not all damage is reported to the police, such as hit and run incidents[290] and damage found later during routine inspections by PSNH. Further, obtaining police reports has been complicated by COVID-19 and freedom of information issues.[291] In some cases, long delays have occurred.[292]

If an Administrator is unavailable due to absence, such as vacation or illness, there is a backup procedure in place to ensure that the monitoring for incidents continues.[293]

[285] Claims Panel #1
[286] Interviews #71 and Interview #72
[287] Claims Panel #1
[288] Interview #71
[289] Interview #71 and Claims Panel #1
[290] Claims Panel #1
[291] Interview #71 and Interview #72
[292] DR BPA 12-005(d)
[293] Interview #72

7.6. The job description for the Administrator function does not include the third-party damage function and therefore is out of date.

As part of RCG's investigation, the Administrator's position description was requested. RCG found that the duties within the provided job description[294] did *not* include the third-party incident discovery and claim creation functions.

7.7. The description of the initial portion of the claim process performed within the operating center was detailed in a narrative provided however, the checks and balances are unclear. [295] Combined with the lack of a detailed process flowchart or other similar definitions, RCG is concerned that the claim development process is not well defined, and therefore subject to possible misinterpretation.

The Operations Supervisor determines when to close out a work order[296] and reviews construction work in progress to determine if incidents have not been processed.[297] During a panel interview conducted by RCG, a PSNH participant noted if a claim is not generated, it "*does not percolate in our system.*"[298]

It is unclear to RCG, who is responsible for confirming that no third party can be identified. This would be a control issue as the Operating Center management could circumvent the claims process. RCG found no evidence of this occurring.

Recommendations

R.18 PSNH should develop a formal method to track the status of third-party claims in process but not yet completed at the operating center level.

R.19 PSNH should create an accurate job description for the Administrator position that reflects the importance of the claim's preparation process.

R.20 PSNH should revise the third-party claims process to have the Claims group review incidents where no responsible party is identified or when the operating center management has closed an incident without generating a claim.

[294] DR BPA 11-002
[295] Interview #72 and BPA 12-1 Attachment Page 5
[296] Claims Panel #1
[297] Claims Panel #1
[298] Claims Panel #1

7.8. The process to administer and resolve claims with the responsible party is defined, appears to be functioning well and is appropriately managed.

Once the incident cost is established by the Administrator and approved by Operating Center management, the information is forwarded to the Claims Department, which processes the claim. The Claims Analyst contacts the responsible party and seeks payment[299] based on information in the police report or contact with the responsible party. Supported by a tracking system to follow up on the claims billed[300], the Claims Analyst may make multiple follow-up contacts, negotiate payment arrangements, and, if necessary, request the NH DMV to suspend the responsible party's license for failure to pay for the damage.

Payments are tracked monthly as payment plans extend over time and therefore are monitored.[301] If the responsible party fails to pay after four months, a "14-day letter", which is a notice of the possibility of license suspension, is sent to the responsible party.[302] The Claims Analyst typically allows 30 days for a response and then will request the NH DMV to suspend the license of the responsible party.[303] The possibility of license suspension has proved a good tool for the claims process.[304] When suspension cannot be achieved, the claim will typically be sent to collections.

7.9. While not specifically documented but detailed through RCG's interviews and PSNH's responses to RCG data requests, accounting for third-party damage and the offsetting reimbursement is a defined and managed process.

Once the claims process has begun, the accounting for the claim takes place. Costs are moved from FERC Account 107 Construction Work in Progress to Account 106 Work Completed but Not Classified. Charges are classified according to FERC accounting conventions,[305] and costs are apportioned between capital and O&M accounts[306].

[299] Claims Panel #1
[300] DR BPA 12-008, 16-001 and Claims Panel #1
[301] Claims Panel #1
[302] Claims Panel #1
[303] Claims Panel #1
[304] Claims Panel #1
[305] Claims Panel #1
[306] DR BPA 12-005

7.10. PSNH customers are protected by the PSNH's immediate recognition of potential reimbursement from responsible parties (the Sundry Bill process) while the collection process is underway. The amount recognized is reduced by the reserve analysis.

At the same time, the potential (but not yet collected) Sundry Bill to the responsible party is recognized as an offset in Account 108 Accumulated Depreciation. PSNH provided the FERC accounting guideline that suggests the reimbursement be credited to Account 108 as a recovery from insurance.[307]

The actual level of the reimbursement for an incident is often different than the initial bill, which will decrease the amount credited to Account 108 in a later period. The difference may result from negotiations with the insurance carrier, negotiations with the responsible party, non-payment by various parties, or differences in overhead percentage charges, which may change monthly.[308]

7.11. The accounting process for establishing reserves for non-payment of billed reimbursement is defined.

Periodically PSNH will review the status of reimbursements (Sundry Bills as a whole) and adjust the reserve amounts to reflect the potential for non-payment of the Sundry Bills that have previously been rendered. While the analysis of uncollectible accounts[309] is considered an "art" and uses judgement factors to deal with the "pooled" uncollectible[310], the concept of the uncollectible reserve balance[311] is like the reserve established for customer receivables[312]. PSNH provided the process used to establish such reserves[313] and an analysis from January 1, 2019, as requested by RCG.[314] This process includes input from the Claims group.

Each year an annual budget for damage is established (project # INS9R).[315] A "supplemental" request will be developed if a budget overrun looks possible.[316] The

[307] DR BPA 12-006
[308] Claims Panel #1
[309] Claims Panel #1
[310] Claims Panel #1
[311] Claims Panel #1
[312] Claims Panel #1
[313] DR BPA 15-013
[314] DR BPA 15-014
[315] Claims Panel #1
[316] Claims Panel #1

overrun is not a result of PSNH actions as the damage is caused by third parties, whether identified or not.

7.12. A programming error leading to a misclassification of credits is in the process of correction, and a temporary mechanism is being used in the interim.

A programming error in the implementation of a new software system that interfaces into accounting system resulted in reimbursement credits assigned to FERC Account 107 Construction Work In Progress instead of FERC Account 108 Accumulated Depreciation in the mapping process. This was disclosed in a footnote to a data response rather than during an interview or the body of the response.[317] On follow-up, PSNH indicated that it is transferring the amounts quarterly to correct this misclassification[318] and that a consultant has been engaged to correct the erroneous classification process within the software[319].

Recommendations

R.21 PSNH should develop a flowchart and process narrative to define and illustrate the entire third-party claim process in one document.

R.22 PSNH should correct the software which improperly allocates reimbursements to Account 107 instead of Account 108.

[317] DR BPA 12-005(c)
[318] DR BPA 16-002
[319] Claims Panel #2

Communications

In any regulatory filing, including an application for rate relief, the typical utility has the burden of proof. Implicitly the utility also has a burden to reply in a timely fashion according to the norms in that regulatory jurisdiction.

To facilitate the review of the third-party claim process, PSNH suggested using a Claims interview panel. Ultimately, there were two Claims interview panels. Using interview panels permitted a wide-ranging positive discussion that explained the functions of the involved PSNH groups and their interactions, rather than piecing together details from several interviews.

7.13. Relevant items were not disclosed clearly or in sufficient detail by PSNH in data responses, sometimes to its detriment by not highlighting positive information or actions.

A misclassification by a new software program of reimbursements was disclosed within a footnote to a data response rather than directly disclosed in that data response.[320] Although PSNH had both a short and long-term resolution of the issue, PSNH did not highlight the ongoing, positive actions taken by PSNH.

The extended time to release a third-party claim work order due to a late police report was apparent when comparing various dates within the documents provided as a data response.[321] PSNH did not highlight information that would document a delay beyond PSNH's control due to delayed availability of police reports.

In response to a data request for the Administrator's job description, the response did not highlight that the job description provided was outdated and therefore not useful for the purposes that RCG requested.[322] Only after RCG's informal questioning of PSNH was this situation confirmed.

[320] DR BPA 12-005(c)
[321] DR BPA 12-005(d)
[322] DR BPA 11-002

7.14. PSNH's overall communications, in the context of the review of the third-party damage process review by RCG, was not timely.

The requests to schedule interview panels have taken well over a reasonable two weeks (ten business day) expectation, and no estimated date to schedule the interview panel was provided in the interim period.

Many data responses have taken well over a reasonable two weeks (ten business day) expectation, and no estimated date of delivery was provided in the interim period. In RCG's experience with management and process audits, we have not seen such response times (up to 45 calendar days).

Recommendations

R.23 If PSNH cannot complete a response to a data request and transmit the data response within ten business days, an estimated completion date should be formally transmitted by the tenth business day.

R.24 In its data responses, PSNH should highlight its ongoing and planned responses to issues and the impact of third parties' actions, rather than embedding the issue within the data.

R.25 To facilitate and clarify data requests and data responses, PSNH and the Division should consider adding technical conferences before and after data requests are requested and responded to.