STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 19-057

REQUEST FOR PERMANENT RATES

DIRECT TESTIMONY OF JOSEPH A. PURINGTON AND LEE G. LAJOIE

Grid Transformation and Enablement Program:

Acceleration of Targeted Infrastructure Upgrades

On behalf of Public Service Company of New Hampshire

d/b/a Eversource Energy

May 28, 2019

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I. INTRODUCTION

Q. Mr. Purington, please state your full name, position and business address.

A. My name is Joseph A. Purington. I am employed by Eversource Energy Service Company as Vice President, New Hampshire Electric Operations. My business address is 780 North Commercial Street, Manchester, New Hampshire.

Q. What are your principal responsibilities in this position?

A. As the Vice President of New Hampshire Electric Operations, I am responsible for the safe and reliable operation of the electric transmission and distribution systems of Public Service Company of New Hampshire d/b/a Eversource Energy ("PSNH" or the "Company"), including operation, maintenance, construction and restoration. There are three internal organizations that report directly to me, which are Field Operations, System Operations and Station Operations.

Q. Please summarize your professional experience and educational background.

A. I joined Eversource Energy in February 2014 in my current position as Vice President of New Hampshire Electric Operations. Prior to joining Eversource Energy, I was the Director of System Operations for Iberdrola US, with responsibility for New York State Electric & Gas, Rochester Gas & Electric and Central Maine Power, which is a position I held from 2010 to 2014. I began my career with Central Maine Power in 1987, and remained with the company through its acquisition by Energy East in 1998 and Iberdrola in 2008. Overall, I have approximately 31 years of experience in electric utility operations, including transmission, distribution, substations, system operations and control centers.

I have a Bachelor of Arts Degree in General Studies from Southern New Hampshire University, as well as an Associate Degree in Applied Science from Southern Maine Community College.

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes, I testified recently before the New Hampshire Public Utilities Commission (the "Commission") in Docket No. DE 18-177 in relation to the Company's Reliability Enhancement Program ("REP") extension for 2019.

Q. Mr. Lajoie, please state your full name, position and business address.

A. My name is Lee G. Lajoie. I am employed by Eversource Energy Service Company as Manager of System Resiliency. My business address is 780 North Commercial Street, Manchester, New Hampshire.

Q. What are your principal responsibilities in this position?

A. As the Manager of System Resiliency, I am responsible for the Company's capital budgeting process. In recent years, I have also had responsibility for the REP plan, which supported up to $40 million of capital investment annually targeted at reliability projects. As that program has matured and tapered off, I have taken on broader responsibility for the capital budgeting process going forward. In addition, there are two internal groups that report to me, which are the reliability reporting group and the distribution automation group.

Q. Please summarize your professional experience and educational background.

A. I graduated from Northeastern University in Boston, Massachusetts in 1985 with a Bachelor of Science in Electrical and Computer Engineering, Power Systems, and from Southern New Hampshire University in Manchester, New Hampshire in 2016 with a Master of Business Administration degree. Upon graduation from Northeastern University, I was hired by PSNH and have held various positions in Distribution Engineering, Field Engineering, New Service, and Distribution Maintenance with increasing responsibility through my current position as Manager of System Resiliency.

Q. Have you previously testified before the Commission?

A. Yes, I have testified before the Commission in past proceedings, including Docket No. DE 17-076, Motion for Approval of Reconciliation and Continuation of Reliability Enhancement Program, and Docket No. 17-176, Petition for Continuation of Reliability Enhancement Program.

Q. What is the purpose of your joint testimony?

A. Our testimony introduces a key proposal of the Company's permanent rate filing, which is the Grid Transformation and Enablement Program ("GTEP").

Q. What is the purpose of the Grid Transformation and Enablement Program?

A. At its core, the GTEP is a proposal to raise the condition of the Company's distribution system in the State of New Hampshire to a level that is necessary to meet the growing expectations of customers for fewer service interruptions; shorter restoration times, particularly following major weather events; and the integration of a range of advanced energy solutions that achieve operational goals, while at the same time reducing greenhouse gas emissions. PSNH is making this proposal to take a meaningful step forward in addressing the confluence of factors that are substantially and irrevocably changing the operating environment for electric distribution utilities.

As described below, the GTEP would operate in concert with the Company's base capital program to provide critical support for accelerated investments targeted to fortify the overhead distribution system with more resilient equipment and materials, while at the same time creating the operating platform necessary to enable the integration of advanced technology solutions on a cost effective and lasting basis. If approved by the Commission, the GTEP would also provide the Company with the ability to identify, plan and develop projects to meet customer demand for increased system integration of clean energy technologies, including two specific demonstration projects that the Company has already identified to serve as important learning opportunities to further this objective.

Q. What are the major components of the proposal and how are these components presented for discussion in the Company's testimony?

A. The Company's GTEP testimony is presented in two parts, with each part addressing one of the main components of the program. First, the GTEP would enable the Company to accelerate investments in specific categories of distribution facilities, targeted to fortify the overhead distribution system with more resilient equipment and materials, reduce storm-related outages, and better prepare the system to serve as the platform for the integration of advanced energy solutions. Specifically, this element of the GTEP would allow the Company to accelerate investments in: (1) distribution pole replacements; (2) distribution line reconstruction and reconductoring; and (3) substation renewals. Together, these investments will enable greater progress in the conversion of the overhead system from its outmoded construction to a sturdier, more resilient construction utilizing modern-day equipment and materials. This part of the GTEP is presented in our joint testimony, and includes an overview of the current state of the PSNH distribution system, explains the challenges that PSNH must be ready to meet in the coming years, and presents the accelerated capital initiatives that constitute the first component of the GTEP.

Second, the GTEP would enable the Company to identify, plan and execute on the integration of advanced energy solutions that would serve the overhead system (and the customers that rely on it) on a multi-dimensional basis, providing both operating and clean energy benefits for customers. In relation to this second aspect of the GTEP, the Company is proposing two demonstration projects, which are designated as the Westmoreland Clean Innovation Project and the Oyster River Clean Innovation Project. These projects are described in the testimony by Company witnesses Charlotte B. Ancel and Jennifer A. Schilling.

Q. How has the Company addressed cost recovery for the GTEP?

A. The Company is proposing a rate-making mechanism to support the accelerated investments and advanced technology integration of the GTEP. The rate mechanism is discussed in detail in the testimony of Company witnesses Eric H. Chung and Troy M. Dixon. As Mr. Chung and Mr. Dixon explain, the flow-back of excess deferred income-taxes arising from the Tax Cuts and Jobs Act of 2017 provides a rare opportunity to make a step change in the work performed to meet the needs of customers through a conversion of the overhead electric system to a more resilient, integrated and advanced grid.

Q. Why is PSNH making the GTEP proposal as part of this rate case?

A. This is the first base-rate proceeding that the Company has filed in 10 years. In those 10 years, a vast sea-change has occurred in terms of the need for the distribution system to be more reliable and resilient to meet the growing expectations of customers; for protection from the impacts of climate change experienced by customers in terms of the significant ramp-up in the frequency and severity of major weather events; for changes in service alternatives arising as a result of the transition to a digital economy; and for options to participate in clean technologies the installation of distributed energy solutions and other opportunities. The confluence of these dynamics, along with an increasing need to maintain and enhance both physical and cyber-security, is fundamentally changing the Company's operating environment and is doing so on an unprecedented scale.

Consequently, in this case, the Company is presenting a comprehensive view of the state of the distribution system to explain the imperative that exists for the Company (and its customers) to step-up the conversion of the system from an outmoded construction to a sturdier, more resilient construction utilizing modern-day equipment and materials and to achieve a level of system condition that is necessary to meet these challenges.

Q. Is GTEP a repeat of the REP?

A. No. Although converting the overhead system to a sturdier, more resilient construction will inevitably reduce the frequency of customer interruptions during routine operations, the GTEP investments are targeted at overhead equipment and facilities upgrades that will make the distribution system more durable and resilient to major weather events, while also preparing a platform for the integration of advanced technologies that have the potential to produce multi-dimensional benefits. There is no alternative to this condition upgrade and completing the condition upgrade is necessary to bring the system to a basic level of resiliency and integrity. By virtue of the REP and the Company's organizational and process changes since 2012, the Company has made great strides in improving the reliability of service to customers. We discuss these improvements later in our testimony. However, the Company recognizes that it must have a broader focus to meet the needs of customers over the long term. Therefore, the GTEP is designed with an overriding, primary objective of preparing the distribution system on a broader basis to meet customer needs today and into the future, although implementation of GTEP will have reliability benefits as a corollary impact.

In contrast, the REP served specific purposes over time that were focused on reliability through asset replacement and more recently vegetation management. At its peak, the REP was approximately $40 million of annual capital, and the program has matured and tapered off. The last year of spending at the $40 million level was the year ending July 1, 2017. The REP was subsequently extended through the end of the year, at $10 million for the half year or $20 million annually; and in 2018 it was reduced to $9 million. Over the last year and a half of the program, REP was focused more on vegetation management and some reliability measures.

Q. Is GTEP a substitution for or overlay of grid-modernization?

A. No. The work that would be completed through the GTEP is not a substitution for or overlay of the type of investment typically envisioned as "grid-modernization," although the objective and outcome of the GTEP is to establish an operating grid that is comprised of modern-day equipment and materials that are in a readiness state for the integration of advanced energy solutions. The work plans and investments associated with the Commission's grid-modernization initiative are separate from this program. The GTEP is a necessary precursor and complement to grid-modernization investment; but is not a substitute or overlay for that investment.

Q. Is PSNH working to advance clean energy innovation in the State of New Hampshire in ways other than through the GTEP?

A. Yes. The GTEP includes the two demonstration projects that will be important to advance this objective, and on an overall basis the program is supportive of the Commission's investigation of grid modernization initiatives. More broadly, PSNH is considering initiatives outside of the GTEP that will move the State of New Hampshire forward on clean energy innovation. For example, PSNH is exploring options for a public-private partnership to develop an electric vehicle ("EV") fast charging corridor for New Hampshire, in coordination with the state EV Commission. Under this project, PSNH would invest approximately $2 million of base capital to construct distribution facilities, primarily service drops, to energize a series of EV fast chargers. An EV fast charging corridor would provide multiple charging sites along New Hampshire's most thoroughly traveled roadways and thereby advance in-state economic development, promote tourism and support EV drivers who live and work in New Hampshire. In addition, funding for the chargers (approximately $50,000 each) is envisioned to come from the 2016 Volkswagen settlement trust. The chargers would be owned by third-party charging vendors that are selected through a competitive bid process. This project would support customer deployment of up to 48 50kW DC fast-charging stations at approximately 12 sites throughout the Company's service territory, with the infrastructure to support future expansion of up to 40 additional DC fast chargers.

Q. How is your testimony organized?

A. Our testimony presents the first part of the Company's GTEP proposal, organized into the following sections:

- Section I of our testimony is the Introduction.
- Section II of our testimony provides an overview of the state of the Company's electric distribution operations, describes the current performance trends and challenges experienced on the system, and discusses the factors influencing those trends in recent years. Section II also discusses the base capital plan and step adjustments proposed as part of the rate plan that are necessary to support the execution of that plan. Lastly, Section II describes the current pace of investment and the reasons it is necessary to convert certain outmoded overhead distribution equipment and materials to enable resiliency and the integration of advanced energy solutions.

- Section III of our joint testimony presents PSNH's proposal to accelerate the pace of investment for pole replacements, distribution line reconstruction and reconductoring, and substation renewals, targeted at fortifying the system for resiliency and energy enablement. This section discusses the benefits that will be produced by converting and upgrading these facilities and the approach taken by PSNH in deciding on the appropriate acceleration of needed investments. This program balances impact to customers from a rate perspective with the impact of operational outcomes. This section also discusses each category of investment and the incremental investments and expected outputs.

- Section IV provides concluding remarks to our testimony.

II. OVERVIEW OF THE PSNH DISTRIBUTION SYSTEM

A. Composition of the System

Q. Please describe the PSNH electric distribution business.

A. The Company's distribution business consists primarily of the delivery of electricity to residential, commercial and industrial customers. As of March 31, 2019, PSNH furnished retail franchise electric service to approximately 519,000 retail customers, including approximately 441,450 residential customers, 75,000 commercial customers and 2,735 industrial customers. The Company provides distribution service in 211 cities and towns in New Hampshire, covering a service area of approximately 5,630 square miles. The Company's customer base represents approximately 70 percent of the total electric customers in the State of New Hampshire.

Q. Would you please describe the types of facilities, plant and equipment comprising the PSNH electric distribution system?

A. Yes. The Company's electric system consists of approximately 1,040 miles of transmission lines, and 12,200 miles of overhead distribution circuits, including approximately 3,000 miles of road-side, three-phase distribution circuits and 600 miles of distribution lines within off-road rights-of-way. The Company also has approximately 1,800 miles of underground distribution lines. Approximately 17 percent of the distribution system is considered backbone and the remaining 83 percent of the system consists of overhead laterals stemming off backbone circuits. The longest, single circuit is 199.89 miles long and the shortest is just under one-tenth of a mile. PSNH has 139 distribution substations (including shared substations), and 184 substation transformers ranging from 1.5 MVA for a small 34-4 kV station to 140 MVA for the largest 345-4 kV stations. The Company has distribution facilities attached to approximately 455,000 jointly or solely-owned poles throughout the state, and has maintenance responsibility for approximately 276,000 of these poles.

Q. With respect to the 3,000 miles of road-side, overhead three-phase distribution circuits referenced above, what is the composition of the materials and construction of this infrastructure?

A. Historically, the Company's road-side three-phase distribution circuits were constructed almost exclusively of wooden distribution poles, with wooden crossarms and bare wire with no insulated covering over the conductor. Until approximately four years ago, the Company's standard pole construction was a relatively small diameter Class 4 pole. The conductors can range from #6 copper wire installed many decades ago, to larger 477,000 circular mil aluminum conductors ("ACSR") installed in more recent years.

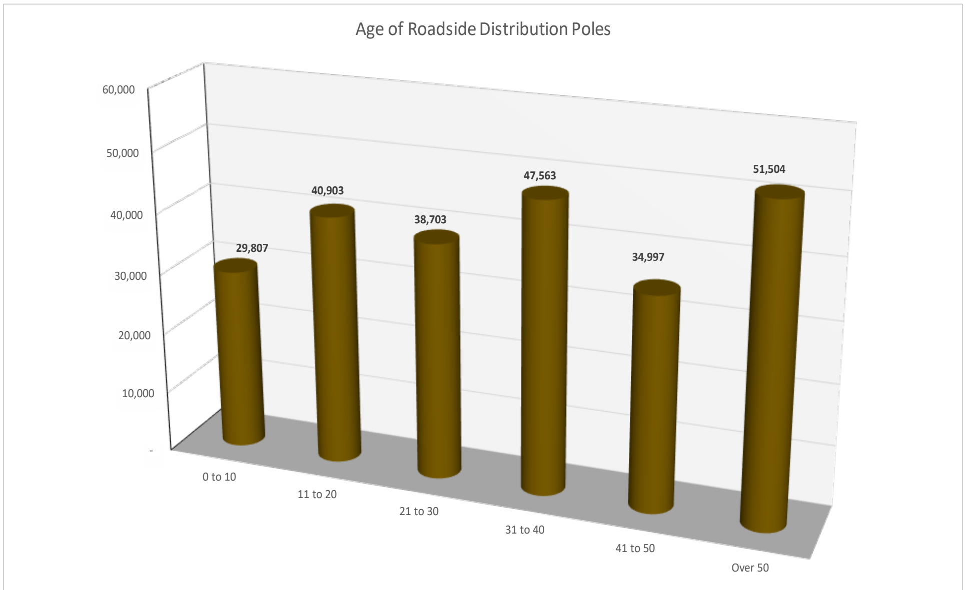
Q. With respect to the 600 miles of distribution lines within off-road rights-of-way referenced above, what is the composition of the materials and construction of this infrastructure?

A. PSNH's off-road infrastructure was originally developed as a sub-transmission system. Similar to the Company's road-side construction, these off-road lines were typically constructed on wooden poles with wooden crossarms and bare wire conductors. The conductor sizes range from small copper conductors installed many decades ago, to larger 795,000 circular mil ACSR installed more recently. Right-of-way widths vary from 50 to 100 feet, more or less, and accessibility of these facilities is challenging. Over time, this system has evolved to operate as part of the distribution system as the Company moved to utilizing 34.5 kV as a distribution voltage starting in the 1960s.

Q. Are there challenges presented by the physical characteristics of the Company's existing distribution poles?

A. Yes. One of the most significant concerns that the Company has with the overhead distribution system is the large proportion of older, outmoded utility poles existing on the system. Currently, over 29 percent of the 276,000 distribution poles maintained by PSNH are over 40 years old. Approximately 50,000 of these poles are over 50 years old. Figure 1, below, depicts the age groupings of the Company's distribution pole inventory:

Figure 1: Vintage of Distribution Poles (Roadside)



The older poles tend to be smaller Class 4 poles that are less resilient in major weather events and more vulnerable to damage from falling trees and tree limbs.

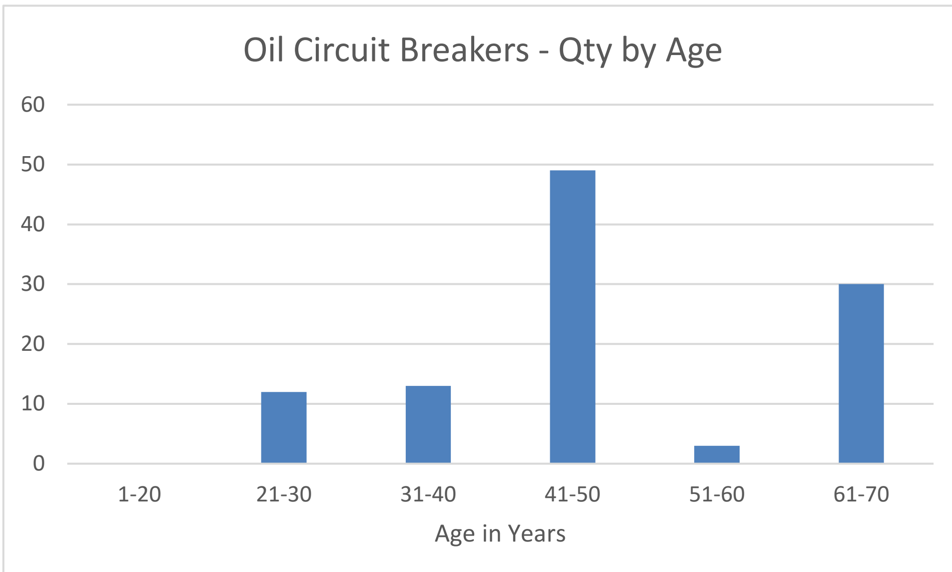
Q. Are there also challenges presented by the physical characteristics of the Company's road-side three-phase lines and off-road lines?

A. Yes. Because these systems are predominantly bare wire on older wooden poles, these facilities lack resiliency in major weather events and are extremely vulnerable to damage from falling trees and tree limbs. PSNH has seen substantial benefits from its comprehensive vegetation-management programs to improve reliability and resiliency, but the vulnerabilities remain due to this older construction. In addition, the off-road lines are often difficult to access and therefore often result in prolonged outages.

Q. What are the physical characteristics of the Company's substation equipment that pose operational challenges?

A. A significant number of the Company's oil circuit breakers ("OCBs") are in excess of 40 years old. Figure 2, below, depicts the age of the Company's oil circuit breakers:

Figure 2: Vintage of Distribution Substation Oil Circuit Breakers



The older technology of using oil as the arc interrupting medium has been supplanted by vacuum interrupting breakers ("VCBs") and the Company has been installing VCBs exclusively for over 20 years. In addition to the flammability of the oil in OCBs, the mechanisms require more frequent and costly maintenance, and have been the cause of some widespread outages in the past, when the breakers failed to operate as quickly as intended. Some of these older breakers also have bushings containing oil with high levels of polychlorinated biphenyls (PCBs). Failure of some of these bushings have resulted in extensive and costly cleanup efforts. Newer vacuum breakers have proven to be very reliable, have less frequent and lower cost maintenance requirements, and do not have the environmental issues of OCBs. Since 2002, the Company has replaced over 90 OCBs with VCBs, either as a proactive approach or as part of larger substation rebuild projects.

Q. In addition to serving its distribution customers, is the Company also facing a growing number of distributed energy resources that are interconnected or seeking to interconnect to the distribution system?

A. Yes. PSNH currently has over 440 megawatts ("MW") of independently owned distributed energy resources ("DER") operating on the distribution system at 34.5kV and below. Table 1 below provides a summary of the types of DER on the system:

Table 1: Distributed Energy Resources

Unit Type	Number of Units	Total MW
Solar	>6,100	66 MW
Wind	2 large-scale, plus several small customer-sited	38 MW
Hydro	77	131 MW
Biomass	6 (1 dormant)	90 MW
Landfill Gas	9	28 MW

In addition, there are approximately 220 MW of large-scale solar projects seeking to interconnect at distribution voltage, which are currently the focus of study by PSNH. The integration of these facilities place greater demands and challenges to the operation and flexibility of the distribution system.

B. Current Performance Levels and Organizational Structure

1. Performance Metrics

Q. How does PSNH evaluate system reliability?

A. The Company typically evaluates service reliability based on several metrics, including SAIDI[1], SAIFI[2], CAIDI[3], and CIII.[4]

Q. What is the primary cause of outages on the distribution system?

A. New Hampshire is one of the most heavily forested states in the country, and most of the outages on the Company's system are caused by trees and tree limbs, which is why vegetation management has been and continues to be a top priority for the Company. Figure 3 below shows the substantial impact of tree-related outages:

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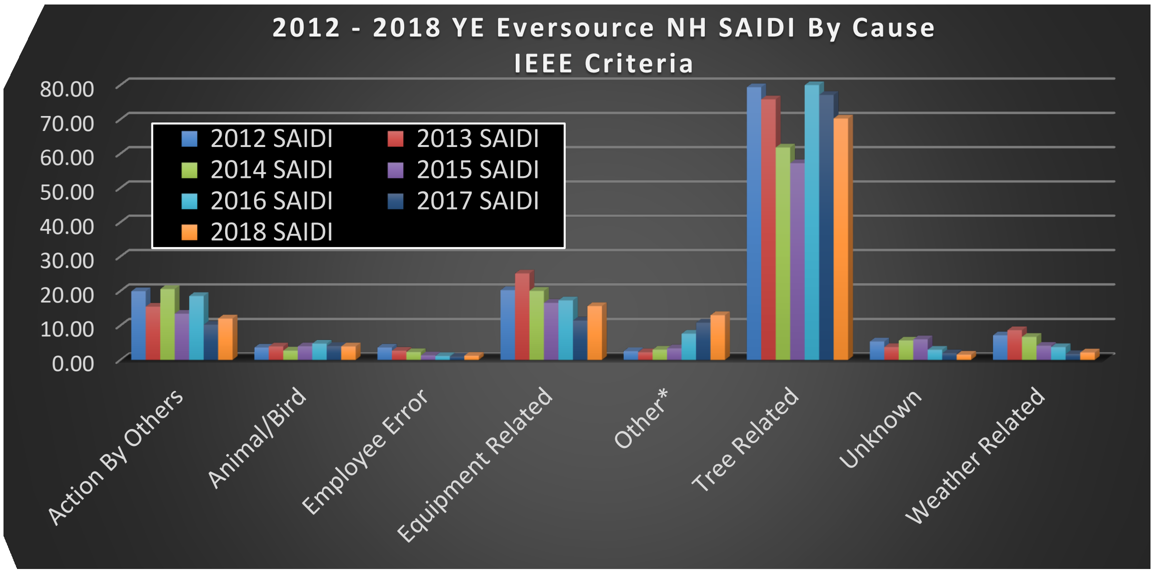
[1] SAIDI, the System Average Interruption Duration Index, is the average interruption duration in minutes per customer served. It is determined by dividing the sum of all customer interruption durations during a year by the number of customers served. SAIDI = sum of customer interruption durations/total number of customers.

[2] SAIFI, the System Average Interruption Frequency Index, is the average number of times that a system customer is interrupted during a year. It is computed by dividing the total number of customers interrupted in a year by the average number of customers served during the year. A customer interruption is considered to be one interruption to one customer. SAIFI = sum of customer interruptions/total number of customers.

[3] CAIDI, the Customer Average Interruption Duration Index, is the average service restoration time or the average interruption duration for those customers interrupted during a year. It is determined by dividing the sum of all customer interruption durations by the total number of customers interrupted in a year. CAIDI = sum of customer interruption durations/total number of customer interruptions.

[4] CIII, the Customers Interrupted per Interruption Index, is the average number of customers without power per interruption. It is determined by dividing the number of customer interruptions in a year by the total number of interruptions.

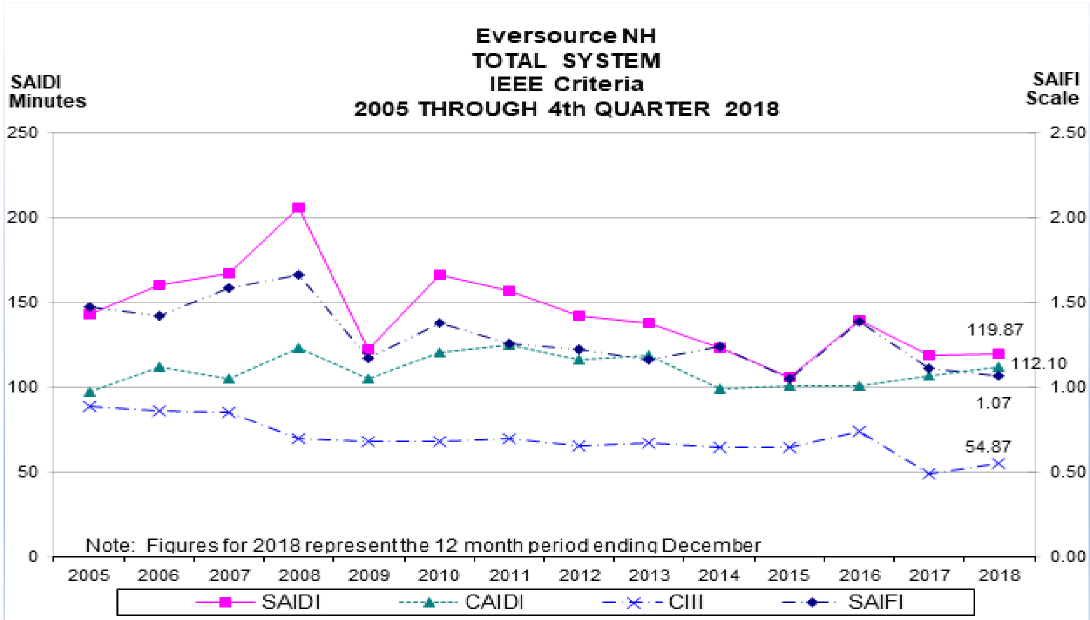
Figure 3: SAIDI by Cause (2012-2018)



Q. Has the Company's reliability performance shown steady improvement in recent years?

A. Yes. As shown in Figure 4 below, the Company's reliability metrics have all be trending down, which means that the duration and frequency of outages experienced by customers are decreasing over time.

Figure 4: Reliability Metrics



From 2008 to 2018, the frequency of outages experienced by a typical customer was reduced by 36 percent; the system average duration of an interruption decreased by over 40 percent from 205.6 minutes to 119.9 minutes; and the average number of customers experiencing a system interruption decreased from 70 to 55, a 22-percent reduction.

Q. What are some of the factors that have contributed to these improvements?

A. There are several factors that have contributed to the improved level of reliability on the PSNH system. Overall, these significant improvements are made possible by the capital investments made in the Company's distribution system, as well as vegetation management work. Some of these investments include pole top distribution automation, circuit ties, replacement of antiquated and obsolete equipment, and relocation of overhead lines from off-road to road-side. For example, in the past five years, the

Company has invested approximately $100 million in distribution automation, which allows for remote switching capability creating the opportunity to restore customers in under five minutes through operator actions from the control center. These investments have contributed to an improvement in SAIDI because instead of experiencing relatively longer outages while the Company travels to the site to manually switch customers, the Company can restore power remotely within a much smaller window of time. About 28 percent of customer interruptions experienced in 2018 were resolved in under five minutes due to the distribution automation already installed on the system.

2. Organizational Changes and Technology Upgrades

Q. What other factors are contributing to service reliability on the current system?

A. Since the time of the Company's last rate review, PSNH has instituted changes that include organizational restructuring, processes improvements utilized in running the business, and utilization of technology with the sole focus of improving system reliability, system resiliency, operational efficiency and customer service. As stewards of the system, these foundational changes are designed to achieve maximum efficiency in operations and cost while improving the customer experience. PSNH continues to optimize its distribution business operations to capture the benefits of the following critical elements:

1. Implementing an organizational structure focused on operating, constructing and maintaining the system;
2. Making smart investments on the distribution system with technology and infrastructure to improve reliability, resiliency and operational efficiency;

3. Leveraging advanced technologies that promote situational awareness to improve restoration and reduce response time, along with increasing communications both internally and with customers; and
4. Improving planning and scheduling processes to execute the Company's work plan.

These measures have produced demonstrable benefits, as shown by improvements in PSNH's performance metrics.

Q. Please describe in more detail the organizational changes PSNH has implemented to meet these objectives.

A. In 2014, the Company realigned its organization into the core functional areas of Engineering, Field Operations, Substation Operations and System Operations. Each of these organizations is led by a director-level position. These core functional areas are supported by Integrated Planning and Scheduling, Operations Support, Customer Care, Emergency Preparedness and other Eversource service organizations. These changes resulted in an organization that is keenly focused on becoming a more efficient and agile organization keeping the best interest of customers and the system in mind while executing the overall work plan and responding to outages and trouble calls.

Q. Please provide a brief description of each core functional area.

A. *Engineering* works as a centralized team with responsibility for all design, engineering and technology functions necessary to perform distribution operations. Engineering includes substation engineering, protection and controls engineering, telecommunications engineering, geographic information system ("GIS") and system resiliency. This alignment of engineering functions promotes a stream-lined decision-making focus and standard distribution-system design. Additionally, the Engineering organization is responsible for the Company's reliability and system resiliency strategies and system capital-expenditure plan.

Field Operations maintains and constructs the distribution system. Field Operations is a centralized team incorporating the Company's field maintenance and construction resources into a single organization. This organization is also responsible for first response to outages in areas not covered primarily by the Troubleshooter organization. In addition, there are five operating regions (Western, Eastern, Northern, Southern and Central) in place of the three former divisions (Central-Southern, Seacoast-Northern and Western). The Western Region incorporates the Keene and Newport Area Work Centers and the Peterborough satellite office. The Eastern Region incorporates the Rochester, Epping and Portsmouth Area Work Centers. The Northern Region incorporates the Tilton, Lancaster, Chocorua and Berlin Area Work Centers and the Colebrook satellite office. The Southern Region incorporates the Derry and Nashua Area Work Centers. The Central Region incorporates the Bedford and Hooksett Area Work Centers.

Supporting Field Operations is an Integrated Planning and Scheduling department that is responsible for the scheduling and execution of PSNH's work plan. This department reviews the work plan, determines the capabilities the internal line work force and determines whether additional line contractor resources need to be utilized to execute the work or if simple movements of internal line workers will suffice. This centralized planning approach allows for efficient scheduling and execution of work across the service territory.

<u>*System Operations*</u> is responsible for all aspects of electric transmission and distribution system operations, including coordination of system-restoration activities, with the central objective of limiting the frequency and duration of customer outages. The System Operations organization includes two departments: the Integrated System Operations Center ("ISOC") and the Troubleshooter organization.

The ISOC incorporates the Electric System Control Center ("ESCC") and the Distribution System Operations Center ("SOC"). The ISOC is responsible for the integrity and operation the electric transmission and distribution system. The ESCC is the transmission operator for the State of New Hampshire, including the underlying distribution system that supports the transmission system as well as transmission feeds to wholesale customers. The SOC, established in late 2014, is responsible for operating the distribution system and restoring power when outages occur through remote operation of automated devices on the distribution system and/or dispatching first responders. The SOC is also responsible for maintaining coordination of responding field resources. PSNH's integrated control center approach for managing the electric system capitalizes on installed system technology, which provides greater system situational intelligence for the control center employees.

The Troubleshooter organization, established in 2015, is described in greater detail below. This organization is a critical component of the Company's commitment to reduce the duration of customer outages, as well as supporting the operations and maintenance of the system through reliability initiatives.

Station Operations operates, maintains, inspects and constructs substation assets across the service territory. They are also responsible to restore power when outages occur in substations. Like Field Operations, substation personnel report to various area work center locations within each region. Within the Station Operations organization is the Communication and Control department, which is responsible for installing and maintaining the communication network utilized for the distribution automation on the system.

Q. Has PSNH experienced efficiencies from these changes?

A. Yes. The organizational re-structuring created a "construct-and-maintain" organization, with Field Operations and Station Operations, and an "operate-and-restore" organization, with System Operations. The organizational changes have promoted a culture within the Company that is focused on operating the system efficiently, including outage response (restoring outages then repairing), planning and executing the work plan, mitigating risk on the system every day, and emergency preparedness and response.

Field Operations consolidated the Company's transmission and distribution line workforces into one organization and encompasses all area work centers. In moving from three divisions to five regions of approximately 100,000 customers each, the organization provides greater management oversight into the customer base and the work being executed within each region. The smaller regional construct is more efficient to manage due to the reduced geography. All of the field construction work, with the exception of major projects, is now in one organization. In addition, the Company has seen other operational efficiencies, which include the following:

- Daily conference calls to review system performance from the previous 24 hours;
- Second shift work hours implemented from Memorial Day to Labor Day;
- On-call line personal taking home Company bucket trucks for quicker response;
- Utilization of transmission line workforce in storms on distribution outages;
- Utilization of line contractors to manage peak work load; and
- Partnerships with IBEW & Manchester Community College for the Company's line apprenticeship program.

In addition, the SOC within System Operations, as well as the Troubleshooter organization, have brought efficiencies to service restoration and have improved response times in many parts of the Company's service territory. Prior to the establishment of the SOC, trouble calls were dispatched through each area work center during normal business hours. After hours, all trouble calls were handled through the call center and were dispatched out to an on-call line worker through a pager. This archaic methodology did not provide the necessary system situational awareness needed to manage the system in today's environment.

Station Operations created efficiencies by combining the Company's transmission station workers and distribution station workers into one workforce reporting to a single director.

These groups were separate prior to 2014. The combination now allows the Company to deploy and utilize its personnel more effectively on substation issues. Previously, the Company would send two qualified workers to the same substation, one to cover transmission work and the other to cover distribution work. Under the combined organization, the Company can now send just one qualified worker to cover both transmission and distribution work within a substation.

Q. Have these changes had a positive impact on performance?

A. Yes. These changes have helped the Company's response times as well as its ability to execute on its capital investment portfolio through more efficient deployment of resources. In turn, the Company's execution of that portfolio has helped reduce the frequency of outages.

Q. Do you have additional examples where these organizational changes have improved safety and efficiency?

A. Yes. When the Company established the System Operations organization, it shifted control of the system from the individual regions to centralized control within that organization. As a result, the System Operations control centers are responsible for activities such as maintenance work, construction projects and other circumstances that require an outage on the system. For these activities, permission must be obtained from the ISOC so they are aware who is working on the system, where the work will be performed and how long the system will be out of its normal configuration. This process also provides enhanced situational awareness of day-to-day activities on the system, for both planned and emergent work. As the Company continues to automate technology on the system, this process is important because it enables the ISOC to know where all of the workers are on the system.

The installation of distribution automation also supports a robust communication process on any potential issues that happen on the system, and includes notification procedures that range from the area work center supervisor through the manager of the region to the director of the organization to the Vice President. For example, any interruption for more than 250 customers is communicated up this chain 24/7/365, making service interruptions a very high priority and ensuring proper resources are fully focused on fixing problems expeditiously.

Q. Have these organizational changes and technology upgrades also provided positive benefits in regard to storm preparedness and response?

A. Yes. These organizational changes have enabled PSNH to realize the benefit of coordinated storm preparedness and restoration across the Eversource Energy organization. The Company received support from its out-of-state affiliates, including resources ranging from crews to support personnel to management. The culture of the organization is that everyone is "all in" and everyone has a storm role. The Company's focus is to restore service to customers safely and efficiently.

Technology and system upgrades continue to provide greater and more granular information on system conditions. The Company benefits from having a state-of-the art outage management system ("OMS") that was installed in late 2015. The Company uses the same OMS as its Eversource affiliates, and this has been a significant advantage to the Company. The Company previously had an antiquated mainframe paper-based outage tracking system. The new OMS is fully integrated in the Company's GIS mapping. The OMS functionality of predicted device outage allows PSNH system operators to review outage and trouble information and send responding crews to the appropriate device efficiently. The OMS functionality also enables PSNH to display outage locations on a map and monitor the locations of crew assignments in relation to the outages. In addition, the Company has equipped all line workers in New Hampshire with iPads, so that the control center can dispatch outage and trouble information to them in real time. As a result, the Company is able to obtain and disseminate additional information faster.

Lastly, in addition to the OMS functionality, distribution automation installed on the system provides the system operators in the control center situational awareness and the ability to reduce the number of customers impacted by an outage through smart device switching on the system. PSNH continues to see positive results from distribution automation increases, through system operator switching in under five minutes.

Q. Does the Company's business strategy include an objective to establish the system and control rooms of the future?

A. Yes. The Company's long-term vision is to build a system for two-way power flow and distribution management. Transmission and distribution operations are changing into being able to monitor and respond to distributed energy resources on the system. PSNH seeks to position the system for that evolution, and it is a multi-year effort. This includes organizational as well as technological changes in how the Company runs the system. The Company is preparing the organization, including people, processes and technology for the control room of the future. Moreover, that same strategy will be utilized in preparing the grid for future technologies and how the Company anticipates operating the system to support these advances.

Q. In conjunction with this strategy, is PSNH taking steps to develop the skilled workforce necessary to achieve this vision?

A. Yes. As technology is implemented on the system, the workforce today (and of the future) is much different than ten years ago. As advanced technologies emerge and expand on the system, the Company and its workers must become familiar with how they operate and interact with the system. In addition, the infrastructure to support the system has become more technologically advanced, requiring employees to be fluent in various technologies to maintain and operate the system.

This is also reflected in training. In prior years, fieldworkers were trained using paper and training books. Today, workers use online training tools to learn necessary skills, such as how to connect a transformer to the phases properly and phase it on the system. The Company must now have the resources in place set up these curriculums and teaching tools. In addition, PSNH has developed a Line-worker Certificate Program in collaboration with the Manchester Community College and IBEW to help fill the pipeline for skilled workers. When a student joins the Program, the student is working through the IBEW training program in conjunction with the Company's internal training program.

The field workforce today must have an educational background to understand what is happening on the system from an electrical theory and technological perspective in addition to the physical skills required.

3. *Troubleshooter Organization*

Q. Lastly, would you please provide more detail on the Troubleshooter organization and the benefits the Company has obtained from this initiative?

A. Yes. In the System Operations organization, the Company established a scheduled single-person first responder position, also known as a Troubleshooter, and this has had a substantial positive impact on response times and efficiency. By definition, Troubleshooters are highly qualified and dedicated electrical line workers. In the regions that now have Troubleshooters, these workers are the first to respond to outages or trouble calls, and PSNH's work practices allow them to complete the majority of assignments on their own. This initiative is providing customers with improved customer service levels, increased hourly coverage, and shorter duration of outages. In addition, this organization has also changed the Company's after-hours call-out procedures for the line workforce. The establishment of this organization has allowed PSNH to move to single-person call for additional help, instead of two-person call-outs that were the norm prior to the establishment of this organization.

Q. Please describe the Troubleshooter organization in more detail.

A. Troubleshooters are within System Operations. The organization consists of one manager, three supervisors and 30 Troubleshooters. All of these first-responder positions are union positions. This organization enables the Company to manage a consistent response to outages and other trouble situations and provides a consistent platform and set of expectations for "restore first, then repair."

Q. What regions are covered by the Troubleshooter organization?

A. The Troubleshooter organization was initiated in late-2015 in the Central and Southern regions. This approach was implemented because these regions have the most customers within the smallest geographic area, and therefore were the most effective in which to initiate 24/7 shift coverage. PSNH initially had six Troubleshooters on shift during the day in these areas, and three on at night. These Troubleshooters work 12-hour shifts, seven days a week, 365 days a year.

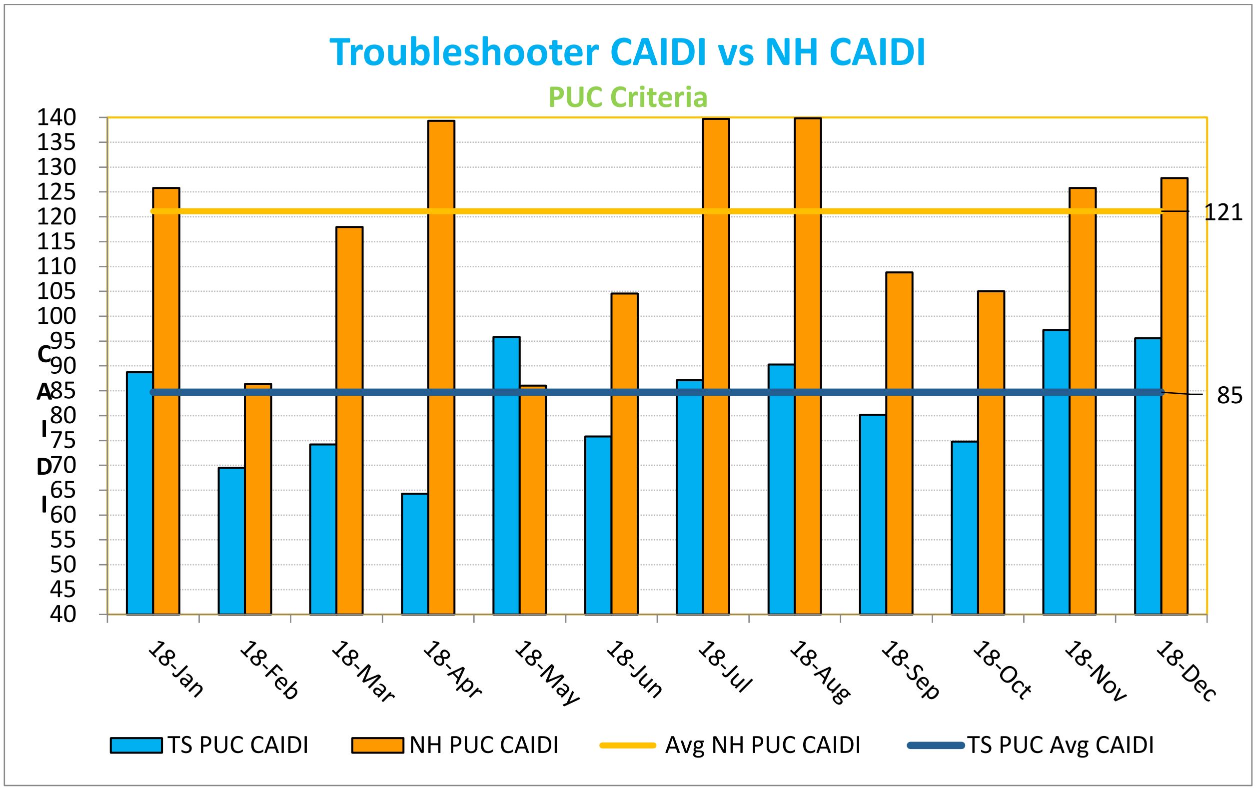
In late 2018 and continuing into 2019, the Company expanded the organization in the Central and Southern regions to include four additional Troubleshooters to work Monday through Friday, 3:00 p.m. to 11:00 p.m., second shift. In addition, the Company is expanding the organization into the Eastern and Western regions with eight Troubleshooters (four in Keene and four in Rochester) that will work 12-hour shifts from (6:00 a.m. to 6:00 p.m.), 365 days a year (with on-call coverage outside of those hours).

The Company expects to evaluate expansion into the Northern region once the Eastern and Western regions are fully staffed.

Q. Have these changes benefited customers?

A. Yes. As shown in the Figure 5 below, these changes have resulted in faster response times and shorter customer interruptions.

Figure 5: Troubleshooter Performance

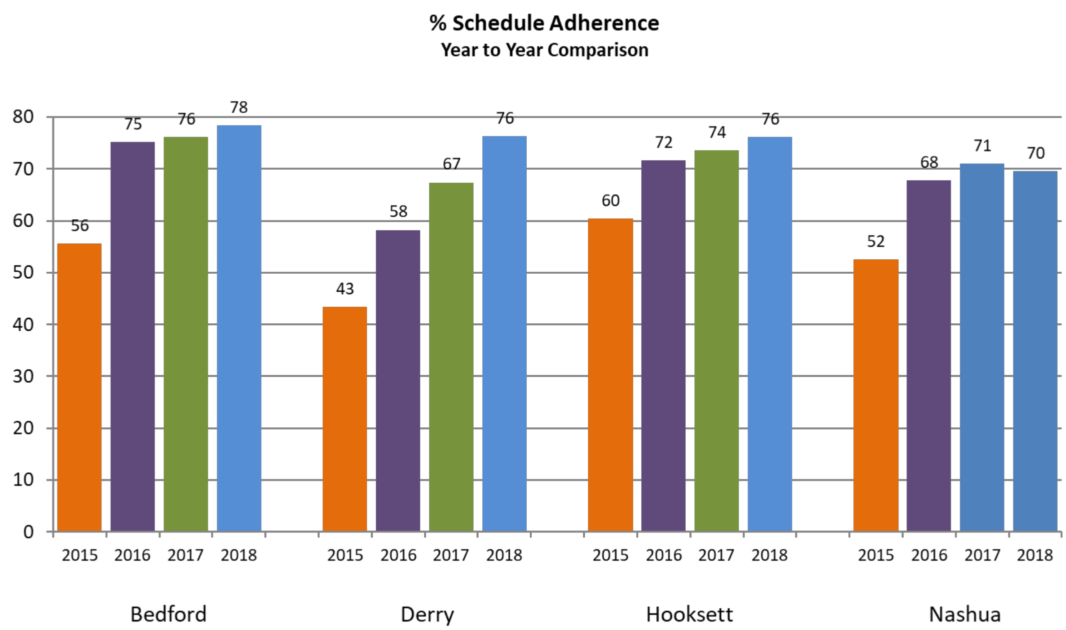


Q. In addition to faster response times, has the Troubleshooter function provided efficiencies in other ways?

A. Yes. Prior to the Troubleshooter function, the Company would have to deploy two qualified workers from field operations to make the necessary repairs, either diverting them from scheduled jobs during the normal workday or deploying them after hours to respond to outages or trouble calls.

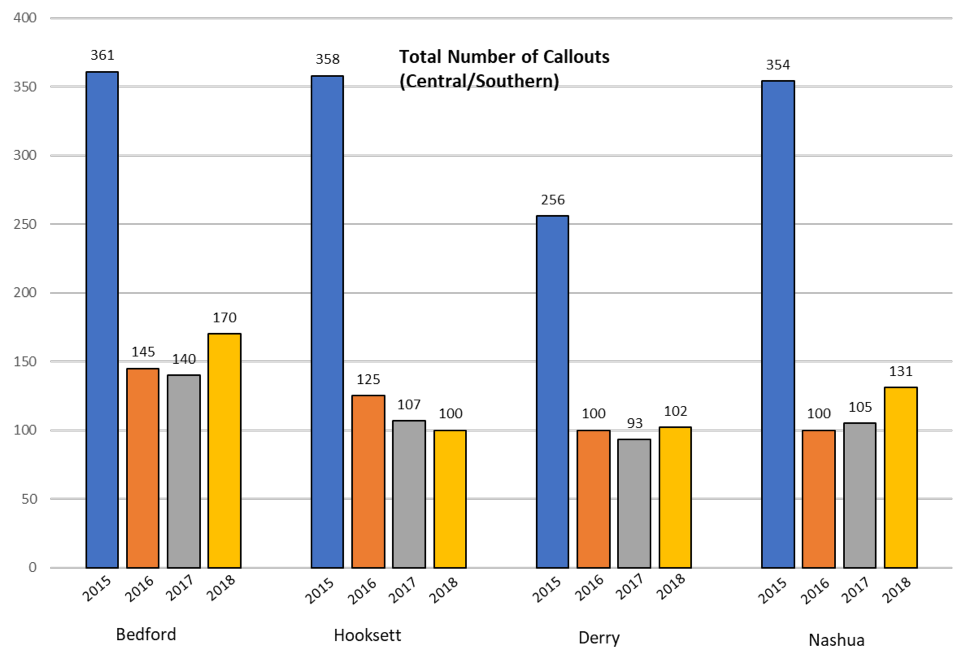
The Troubleshooter function now drives efficiencies in two ways. First, it enables the Field Operations organization to better plan and adhere to its daily work schedule, because the line workers in the regions with Troubleshooters are no longer pulled off jobs during the normal workday to respond outages and troubles. This enables the Field Operations group to plan, set up and execute scheduled work without being interrupted. This is illustrated by the schedule adherence/ maximization charts in the primary coverage area work centers, shown in Figure 6 below.

<u>Figure 6: Schedule Adherence</u>



In addition, line workers in the regions with Troubleshooters are also less likely to be called out after hours, and therefore reduces the time they are unavailable during normal hours due to required rest time. Please see Figure 7, below:

<u>Figure 7: Callouts</u>



Q. How are the Troubleshooters utilized when there are no outages or an insufficient number of outages to fully occupy their time?

A. To the greatest extent possible, Troubleshooters perform other routine, day-to-day work when they are not occupied responding to outages and trouble calls. Typical planned activities would be reliability-focused tasks such as circuit inspections, annual required maintenance inspections, installations of animal guards, lightning arrestor change-outs, and additional maintenance and inspection activities. Troubleshooters also complete customer service requests including installing rubber cover, floating meters, street lighting repairs and flood light additions.

Q. Are there any other anticipated benefits of having additional Troubleshooters working at the Company?

A. Yes. This organization supports PSNH's planning, preparation and response to storms. The greater availability of these resources, on-system, will add to the Company's resources in larger-scale, system-wide emergencies such as storm events. Troubleshooters are often assigned make safe responsibilities at the onset of major storms. As a result, this workforce has proven to be a valuable asset in storm response.

C. <u>Base Capital Plan</u>

Q. Does the Company currently have a capital plan for the distribution system that is directed at investing in infrastructure in the normal course of business?

A. Yes. On an annual basis, the Company develops a five-year forward-looking capital plan for distribution system investments. PSNH's plan of potential capital additions is based upon certain assumptions of capital spending, but the plan does not necessarily translate into particular projects being built at a particular cost in some specific future year. Rather, and consistent with the process described in PSNH's least cost integrated resource plan, proposed capital projects of all types are approved, along with their budgets, on an annual basis as part of a regular budgeting process. Regardless, the plan does set a guidepost for potential future work. The 2019 base capital plan anticipates a total of $137 million for investment in distribution system reliability and forecasts steady-state investments of approximately $134 - $135 million annually through 2023.

Q. Has PSNH increased its capital plan over time to address system requirements for upgraded distribution infrastructure?

A. Yes. Since 2014, the Company's capital plan has increased from approximately $99.2 million to the range of $120 to $140 million annually. The categories of investment and the relative amounts in each category have been relatively stable. Overall, distribution automation and replacement of antiquated equipment are the largest drivers of the capital program in New Hampshire. This includes projects such as replacing substandard poles, substation equipment and transformers, and obsolete circuit breakers.

1. Base Capital Plan Reliability Investments

Q. Historically, has a significant portion of the expenditures comprising the Company's capital investment plan been prioritized on the basis of reliability objectives?

A. Yes. Historically, the majority of the Company's annual capital budget has been devoted to reliability objectives, addressed through projects such as the installation of distribution automation, new circuit ties, substation upgrades and overhead and underground replacement work. In 2019, the Company expects to invest approximately $89.6 million in reliability (including regulatory commitments); approximately $30.0 million in basic business; approximately $11.25 million in new customer growth; and approximately $5.8 million for peak load and capacity. These investment categories are shown in Table 2 below.

Table 2: 2019 New Hampshire Operations Capital Plan (in $000s)

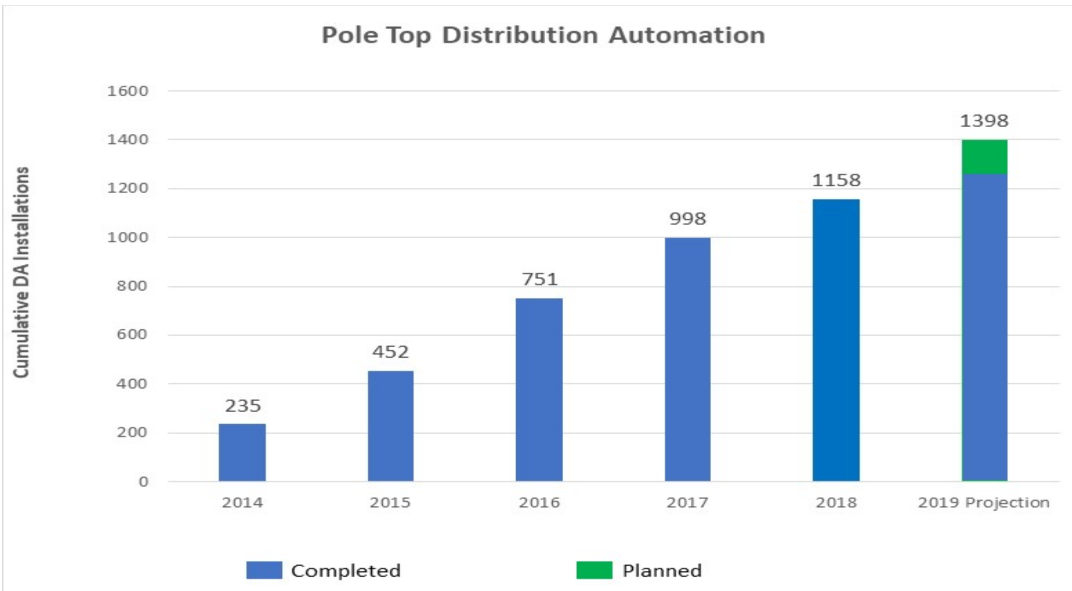
Distribution	**2019 Budget**
Reliability/Regulatory Commitments	$89,611
Basic Business	30,010
New Customer	11,250
Peak Load/Capacity	5,825
Total Distribution Capital	**$136,696**

Q. What types of projects are prioritized in the capital plan for reliability objectives?

A. Work projects prioritized for reliability objectives include pole-top distribution automation, distribution line reconstruction and equipment replacement, conversion of old 4-kV systems to higher voltages, underground equipment replacements, construction of circuit ties, replacing obsolete substation equipment, and projects to improve the ability to provide a backup source of power from other substations in the event of an outage.

In particular, the installation of distribution automation has had a very substantial impact on the improvement of reliability performance. Distribution automation typically refers to pole-top devices that are remotely controlled and that contain built-in sensors that provide information back to operators in the control center in Manchester. The Company started ramping up investment in distribution automation in the fourth quarter of 2014. Prior to 2014, PSNH had approximately 235 distribution automation devices on the system. Since 2014, the Company now will have nearly 1,400 distribution automation devices on the system at the end of 2019. The Company has focused its deployment on the worst-performing circuits, which tend to be in the lower-density areas of the service territory but has steadily been deploying these devices statewide. Figure 8 shows the Company's progress in installing distribution automation on the system:

Figure 8: 2014-2019 Pole Top Distribution Automation Additions



Q. Why did it make sense to start the Distribution Automation program in the lower-density areas?

A. By focusing this program first in the lower-density areas, the Company was able to achieve a marked improvement in response times. PSNH can now remotely isolate troubles down to the smallest area while a truck is dispatched to the location. By isolating the troubles to the smallest possible area, fewer customers experience an interruption and crews can locate the trouble spots more quickly, reducing outage duration.

Q. Does the Company expect that it will continue to install distribution automation equipment on the balance of its system?

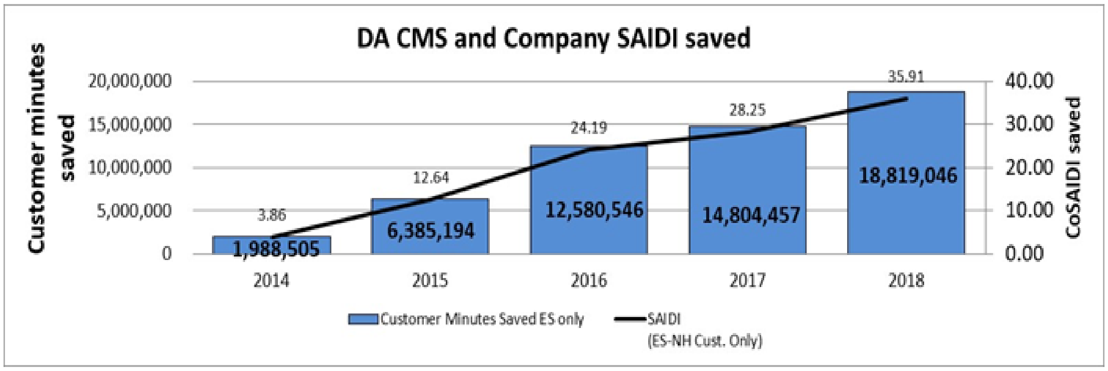
A. Yes. The base capital plan includes continued investments in distribution automation because these same types of benefits will be experienced throughout the system. The Company's long-term plan is to get to a point where there are no more than 500 customers between two devices. While an argument could be made that having even fewer customers between devices is desirable, PSNH's current assessment is that substantial further segmentation is likely not cost-effective. This level of sectionalizing in the current plan will enable the Company to limit interruptions and allow for the remote rerouting of power wherever possible. In major weather events, this type of equipment provides PSNH with the capability to restore customers quicker because the Company can start to isolate troubled areas and restore customers outside of those areas in advance of crews being able to respond. Distribution automation also provides greater vision into what is happening on the system and control of the devices on the system.

In addition, the annual capital investment plan anticipates the installation of circuit ties, which provide alternate feeds and enable system operators to reroute power. Coupled with automation, these investments have reduced the frequency of interruptions for PSNH customers, making service more reliable.

Q. Do you have a chart that demonstrates this benefit?

A. Yes. The Company continues to see these investments pay dividends year over year, as shown in Figure 9 below. In 2018, the Company saved over 35 SAIDI minutes due to distribution automation and operator interaction.

Figure 9: Distribution Automation SAIDI Impact



The additional benefits of automating the system are visible in relation to the restoration curve associated with the October 2017 windstorm. During the event, the Company was able to restore approximately 60,000 customers through remote switching, reducing the peak impact to customers.

As PSNH continues to automate the system, greater amounts of information will be available to the control center, which will allow the Company's operators to make intelligent decisions to reduce the impact of outages to customers. PSNH has demonstrated the success of this investment year over year, and as the Company continues to automate the system, those numbers should continue to improve.

Q. Are there other aspects of the reliability investments that directly improve service quality?

A. Yes. The reliability capital budget also includes system repairs, relocations of rights-of-way, asset condition replacements, and emergent issues, among other items. For all of those items, PSNH looks to improve its plant and assets. It takes each opportunity to make them stronger, smarter and more resilient. Within the capital investment portfolio, the Company does not replace "like for like;" it is always improving.

Q. What are some of the trends you are seeing as a result of these investments?

A. The Company's performance metrics have been steadily improving, as discussed earlier in our testimony. However, outage reports show that the number of outages year-over-year is increasing. Although PSNH has been able to reduce the number of customers impacted through automation, as well as shorten the duration of those outages, the total number of outages is a concern and is a sign of a degradation of system performance.

Q. If the Company has seen improvements in its performance metrics in recent years, why is the number of outages each year increasing?

A. There are several reasons. With the new OMS, the Company has better tracking than it did under the old paper-based system. In addition, the technology associated with distribution automation and sectionalizing enable the Company to specifically identify trouble spots and record them more accurately in the OMS. In the past a larger outage with numerous trouble spots may have been recorded as a single outage, but now, with OMS each trouble spot is its own outage.

Another factor is weather. Over the past decade, the Company has been experiencing an increasing number of storms, including some of the largest storms in its history. At the time of the 2008 ice storm, that event was the largest ever in the Company's history, and was thought to be something that would never be seen again. However, PSNH has experienced 4 major storms with over 200,000 customers impacted since 2008:

- February 2010 Windstorm – 269,000 customers
- October 2011 Snowstorm – 237,000 customers
- Thanksgiving Day Storm, 2014 – 207,000 customers
- October 2017 Windstorm – 217,681 Customers

Q. Has the Company also made annual investments in the replacement of older distribution components to increase the flexibility and resiliency of the distribution system?

A. Yes. Maintaining a distribution-system architecture encompassing a substantial proportion of older system components and outmoded construction makes the system vulnerable to external factors, particularly during larger-scale weather events, and deprives the Company of needed flexibility in managing and coordinating activities on the system. The critical concerns that the Company has relate to: (1) the materials composition and size of overhead utility poles and cross-arms; (2) the materials composition, construction and accessibility of overhead distribution circuits; and (3) substation facilities. These are also the same facilities that need to be upgraded to support the integration of advanced energy solutions.

Q. In order to support the execution of the base capital plan in the coming years, does the Company's proposed rate plan include step adjustments?

A. Yes. The Company is requesting that the Commission approve step adjustments to recover the revenue requirements associated with incremental capital spending under the base capital plan and discrete O&M expenses that will increase the Company's rate base after the Test Year in investment years 2019, 2020, 2021, and 2022. As explained in more detail in the revenue requirement testimony of Mr. Chung and Mr. Dixon, the step adjustments are structured to recover the estimated incremental revenue requirement as shown in Table 3 below:

Table 3: Total Estimated Revenue Requirement

Investment Year 1 (2019)	Investment Year 2 (2020)	Investment Year 3 (2021)	Investment Year 4 (2022)
$15 million	$21 million	$14 million	$16 million

The step adjustments are a reasonable method to allow for more timely recovery of assets placed in service after the test year that are necessary to continue to safely and reliably serve customers after permanent rates go into effect. This proposal is similar to the approach allowed in the Company's 2009 rate case.

Q. What is the timing and mechanics of the proposed step adjustments?

A. As explained by Mr. Chung and Mr. Dixon, the Company is proposing step adjustments to account for capital investments and expenses in 2019 (Investment Year 1), 2020 (Investment Year 2), 2021 (Investment Year 3), and 2022 (Investment Year 4). The Company will make annual compliance filings with the Commission for the prior year's plant additions and select expenses. The Company will file comprehensive documentation with the Commission as part of the annual compliance filings demonstrating actual costs and that all plant additions for the prior Investment Year are completed and in service.

2. *Distribution Poles*

Q. Does the Company have a pole replacement program as part of its base capital plan?

A. Yes. PSNH invests approximately $5 million annually under its current five-year base capital plan for pole replacements. At this level of spending, the Company is able to replace approximately 1,000 poles per year.

Q. How does the Company identify poles to be replaced as part of the base capital program?

A. The Company conducts an annual inspection program in which it evaluates the condition of approximately 10 percent of the pole infrastructure in its maintenance area each year. Thus, each pole on the system is inspected on a 10-year cycle. As a result of the inspection, PSNH typically identifies approximately 1,000 poles each year for replacement. These poles tend to be older vintage poles, often over 40 years old, but the program is not limited to the oldest poles. The program also identifies poles for replacement that have become unsound due to other factors such as rot, soil conditions and insect infestation.

Q. How is the pole inspection conducted?

A. The Company typically hires a contractor to perform its pole inspections. The inspector checks the pole for soundness and uses techniques such as hitting the pole with a hammer, drilling a hole to check for internal rot, and visual inspections of the length of the pole to identify potential problems. The inspector may either accept the pole or reject it, and if rejected the pole will go into one of two categories: (1) poles that need to be fixed and made safe immediately; and (2) poles that can be replaced in the normal course of business.

More specifically, pole inspections are undertaken to determine the condition of wood distribution poles with the objective of replacing poles that pose a risk to the system. The program includes visual and structural inspection in order to ensure a pole meets its minimum strength requirements as defined by the National Electric Safety Code. During the inspection process all poles are visibly inspected and sound tested for signs of decay or severe deterioration. Poles greater than 10 years in age are bored and partially excavated to inspect for decay below the ground line. Poles that do not meet the minimum strength requirements are rejected. Priority reject poles are inspected by the Company within 48 hours from identification as a “priority reject” and must be made safe within 10 calendar days from its identification as a “priority reject” wood pole.

The proactive identification and replacement of poles not meeting minimum strength requirements greatly reduces the probability that the pole will fail in service as the result of adverse weather conditions or the installation of additional equipment by PSNH or third parties. This enhances public safety and reliability while decreasing the need to perform emergency replacements.

Q. How many poles are rejected during the inspection process?

A. The Company has maintenance responsibility for approximately 276,000 distribution poles on its system, and the annual inspection covers 10 percent, or 28,000 of these poles each year. Approximately two percent, or 500, of these poles get rejected and replaced every year. The Company also replaces additional poles due to age and condition, for a total of approximately 1,000 pole replacements each year as part of its base capital program. The number varies each year, although in some years the Company has replaced up to 1,600 poles based on inspection results. In addition, the Company is replacing poles in the normal course of business, as a result of events such as vehicle accidents, storm damage, or due to projects such as reconductoring.

Q. At this rate of replacement, how long would it take to replace all of the poles on the Company's system that are 50 years of age or older?

A. If the Company were to replace solely the 55,000 poles that are 50 years of age or older, at a rate of 1,000 pole replacements per year, it would take approximately 55 years to replace this inventory of poles. By the time these 55,000 replacements are completed, the balance of the 276,000 poles would also be over 50 years old.

Q. When the Company replaces these distribution poles, does it upgrade the condition of outmoded materials composition and construction?

A. Yes. Approximately four years ago, PSNH transitioned to Class 2 wooden poles with composite cross-arms, which provide a stronger and more resilient mode of construction. In the past, the standard construction was a 40-foot Class 4 utility pole, which has a diameter of approximately 10.5 inches at ground level when installed. In comparison, a 40-foot Class 2 pole has a diameter of 12.25 inches at ground level when installed and a strength rating 50 percent higher than a Class 4. The current standard provides substantial resiliency benefits. Similarly, for off-road construction the Company now uses light-duty steel poles in rights-of-way due to their increased strength and resistance to decay, as discussed in more detail below.

3. Reconstruction and Accessibility of Overhead Lines

Q. Does the base capital plan include a systematic program to replace portions of the 600 miles of distribution lines currently located within off-road rights-of-way?

A. Yes. The base capital plan includes a program to reconstruct or relocate portions of the approximately 600 miles of older, overhead 34-kV distribution lines currently located within off-road rights-of-way. This program has been in place for several years and has yielded substantial reliability and resiliency benefits. However, today, a substantial portion of these older facilities remain located in Company rights-of-way.

Q. How does PSNH determine the off-road lines targeted for replacement?

A. The lines targeted for replacement tend to be older distribution facilities constructed on outmoded Class 4 poles with wooden crossarms and smaller size bare wire. There are a number of factors that the Company considers in identifying lines for replacement, including age, materials construction, performance and the number of customers potentially impacted by an outage. The Company also assesses whether it is more cost-effective to relocate the line to a roadway or to reconstruct it in place within the right-of-way. In some cases, the off-road lines are relocated to roadways, which allows easier accessibility in addition to upgrading the condition of the facilities. In other cases, the cost to relocate these lines to roadways is more expensive than rebuilding them in place, as where the right-of-way is the shortest distance between two points to be served on the system. The plan for each off-road line is determined on a case-by-case basis in consideration of the factors specific to the situation. In the Company's experience to date, the majority of these lines have been reconstructed in their same location.

Q. How much capital is included in the base capital plan for off-road line replacement?

A. In the current five-year plan, PSNH is spending approximately $4.7 million per year to reconstruct or relocate off-road distribution lines. This investment allows the Company to address approximately four to eight miles of these lines each year.

Q. When the Company replaces these off-road distribution lines, does it upgrade the condition of outmoded materials composition and construction?

A. Yes. For off-road construction, the Company now uses light-duty steel poles in rights-of-way due to their increased strength and resistance to decay, which provides a substantial resiliency benefit from the older Class 3 wood poles typically used in distribution rights of way. The Company also began using covered conductor or spacer cable approximately five years ago and has seen substantial improvements in performance over undersized bare wire for these off-road installations.

Q. When you say "undersized" bare wire, what is that?

A. Undersized bare wire is any conductor that is smaller than the Company's current standard for overhead lines, which is a minimum of 477,000 circular mils (about one-inch in diameter). The Company estimates that approximately 80 percent of the 600 miles of off-road lines are constructed with undersized bare wire that will need to be upgraded for resiliency and to prepare the grid for integration of advanced energy solutions.

Q. What is spacer cable?

A. Spacer cable, commonly referred to as Hendrix cable, is a type of distribution conductor that has three covered wires in close-knit construction and hangs from a messenger wire with a cross-shaped polymer spacer. With tighter construction than bare open wire, spacer cable is more compact, and the covered conductor is more resistant to tree damage.

Q. Does the base capital plan also have a systematic program to replace portions of the 3,000 miles of road-side, three-phase overhead distribution circuits referenced above?

A. Yes. The base capital plan includes a program to upgrade the condition of its road-side three-phase lines by reconductoring. Similar to the right-of-way program, the Company identifies sections of roadside construction where performance would be improved by installing spacer cable. This work includes upgrading bare wire to spacer cable, and in some cases this also requires upgrading the poles to handle spacer cable construction, in the same manner as with off-road rights-of-way. PSNH does a very good job of tree-trimming, but trees are still the number-one cause of outages. With spacer cable, which is a covered conductor, if a limb comes down it would not cause a trip and reclose, so the customer would not experience a momentary interruption. This work also typically results in shorter spans, thus reducing the vulnerability to tree outages. Overall, when the Company performs this work on its overhead distribution circuits, it upgrades the condition of outmoded materials composition and construction.

Q. What is the Company spending now on roadside reconductoring in its base capital plan?

A. In the current five-year plan, PSNH is spending approximately $6 million annually to reconductor approximately 12 miles of roadside lines per year.

4. *Substation Equipment – Oil Circuit Breakers*

Q. Does the Company make capital investments in substation equipment as part of its base capital plan?

A. Yes. PSNH has a range of projects for substation upgrades. Depending on age, condition and operating history, the Company's projects range from replacing individual components to complete substation rebuilds. The scope of each project is based on the specific circumstances.

Q. What are the criteria that the Company applies in deciding whether to do a replacement of components versus a full rebuild?

A. Each substation is evaluated on a case-by-case basis. For example, the Company is working to eliminate OCBs from substations, because they are outmoded and pose operational and environmental risks. In some cases, PSNH is able to simply replace the obsolete breakers with new vacuum circuit breakers if the other substation components (such as transformers and relays) are functional. In other cases, if the oil circuit breaker is located in a substation with other substandard or obsolete components, the project may entail a full rebuild.

Q. What amount of capital is included in the Company's base capital plan for substation renewal?

A. The current five-year plan includes approximately $1.8 million annually for OCB replacements. This program enables the Company to complete four circuit breaker replacements per year. At this pace, it will take approximately nine years to complete these projects. These projects provide an environmental benefit as well as reduced maintenance, improved safety for employees, and improved reliability in substation operations. New vacuum breakers are more reliable than older oil circuit breakers and do not have the environmental liability of oil-filled equipment. The base capital budget includes a separate category for substation rebuilds.

IV. ACCELERATING THE PACE OF REPLACEMENT FOR ENERGY ENABLEMENT

Q. Why is the GTEP focused on accelerating investment?

A. The Company's current rate of replacement reflects a traditional investment strategy focused on extending the useful life of distribution assets and replacing facilities on an as-needed basis. However, the Company is confronting growing customer expectations for fewer service interruptions; shorter restoration times, particularly following major weather events; and the integration of a range of advanced energy solutions that achieve operational goals, while at the same time reducing greenhouse gas emissions. Accelerated investment in targeted areas would enable the Company to fortify the overhead distribution system with more resilient equipment and materials, while at the same time creating the operating platform necessary to enable the integration of advanced technology solutions on a cost-effective and lasting basis.

In terms of achieving a higher level of resiliency and readiness, vegetation management remains the top priority, providing the biggest impact and improvement for the investment. Trees are the primary cause of customer interruptions on the PSNH system and therefore prioritization of investment on vegetation management work is critical, as the Commission has recognized. However, the most effective measures to improve resiliency and readiness other than vegetation management are the conversion of exposed, antiquated overhead distribution facilities and substation equipment to modern-day materials and construction, as planned in the GTEP. Therefore, the Company has designed the GTEP to allow for an acceleration of the pace of replacement of equipment in specific categories of investment.

Q. What is the Company's proposal for acceleration in relation to the three categories of replacements that would be completed through the GTEP?

The Company's proposal for acceleration for each of the three categories of replacements reflects a reasonable balance of customer bill impact and incremental progress that can be made in each of the three categories. Table 4 below provides the proposed acceleration and incremental spending for each category:

Table 4: GTEP Acceleration Investments

Program Component	Current Annual Capital Investment (2020-2024)	Units Per Year	Years to Comple te	Incremental Annual Capital Investment	Incremental Annual O&M	Units Per Year	Accelerated Completion Years
Pole Replacement	$5.1M	1,000	50	$20M	$5M	4,000	10
ROW Reconstruction &	$4.7M	4-8 miles	n/a[5]	$10M	$0.5M	10-20 miles	n/a
Reconductoring	$6.0M	12 miles	n/a[6]	$5M	$0.25M	10 miles	n/a
Substation Renewal	$1.8M	4	9	$2.5M	$0	5	7
TOTAL				$37.5M			

For distribution poles, the Company has experienced improved performance in major weather events (and day-to-day operations) when older, substandard poles are replaced with higher class poles that are better able to withstand weather impacts. Currently, the Company is investing approximately $5.1 million annually in base budget for pole replacements. This accomplishes, on average, 1,000 poles. Through the GTEP, the Company is seeking to invest an additional $20 million annually, which would be expected to accomplish an incremental 4,000 poles.

For overhead circuits, the Company has experienced improved performance in major weather events (and day-to-day operations) where equipment has been upgraded to

[5] PSNH has over 600 miles of distribution ROW line. Not all is targeted for reconstruction or replacement.

[6] PSNH has nearly 3,000 miles of roadside three-phase line. Not all is targeted for reconstruction.

today's standards. Currently, the Company is investing a combined $10.7 million annually in overhead circuit reconstruction and reconductoring. This accomplishes, on average, 16-20 miles of circuit hardening. Through the GTEP, the Company is seeking to invest an additional $15 million annually, which would be expected to accomplish an incremental 20-30 miles.

For substation facilities, the Company has experienced improved performance as oil circuit breakers have been replaced. Currently, the Company is investing $1.8 million annually in oil circuit breaker replacement. This accomplishes, on average, 4 breakers. Through the GTEP, the Company is seeking to invest an additional $2.5 million annually, which would be expected to accomplish an incremental 5 breakers.

Q. How did you identify these three areas as the optimal initiatives for the GTEP?

A. These areas have the highest potential to mitigate risk to the system. As noted, trees are the biggest cause of outages, and the system currently has thousands of miles of bare wire, which is more susceptible to tree-related outages. There are also tens of thousands of old poles. This combination dictates that they should be the highest priorities. Poles and wires are the foundation of the system, and a strong foundation is necessary for a reliable and resilient system. As each day passes, the 50-plus-year-old poles and exposed wire in many areas will continue to cause issues.

Q. What types of upgrades are typically required for distributed generation?

A. The types of upgrades required for distributed generation are location-specific, based on the size and condition of the distribution lines, the size of the DER, and similar factors.

The initiatives planned in the GTEP would prepare the grid to accommodate a range of DER by assuring that the system will be able to more reliably accept the output of that unit, and by assuring that the benefits of the unit are not subjected to repeated or prolonged outages.

A. __Poles__

Q. Please describe in more detail the GTEP pole initiative.

A. The GTEP includes an additional $20 million to install larger and more resilient poles, which is expected to enable the Company to replace an additional 4,000 poles annually. The Company has consistently met its investment targets in the base capital plan and the REP, and the additional pole initiative will build on the proven benefits achieved through those plans. This initiative will enable PSNH to accelerate the rate of replacement for aged, substandard poles. As described earlier in our testimony, the Company maintains approximately 55,000 poles over 50 years old, so the wave of necessary replacements is accelerating. The number of pole replacements in the base capital plan equates to approximately 1,000 poles annually. At the rate of 1,000 poles per year, it is difficult to make meaningful progress in reducing the number of older, substandard poles on the system. With the additional funding proposed in the GTEP, the Company would be able to replace an incremental 4,000 poles, or approximately 5,000 poles in total per year. Even at this rate, it will take more than a decade to address this subset of the pole population, so it is very important to get started now.

Q. What are the criteria the Company will use to identify pole replacements as part of the GTEP?

A. Similar to the base capital program, the Company will prioritize poles for replacement based primarily on age, condition, location and number of customers served by the circuits on the poles. However, unlike the base capital program where pole replacements are reactive, the GTEP initiative will be more proactive and focused on resiliency.

Q. Will the accelerated program concentrate on poles in specific areas?

A. No, poles 50 years of age and older are spread throughout the state.

Q. Is the GTEP pole-initiative a reliability program or a resiliency program?

A. Although there are reliability benefits from accelerating pole replacement, the biggest impact will be the greater integrity and resiliency of the system through a range of weather events. For example, in recent years it has not been unusual for hundreds of poles to be damaged in a single weather event. The new poles that PSNH is installing are physically larger and stronger and have the potential to withstand more extreme weather conditions as compared to smaller 50-year old poles. It is simply time to scope out a program for upgrading the condition of the system to remove out-moded technology and install modern-day equipment and materials that will help to provide service to customers through the types of environmental conditions that now exists, while also allowing for the integration of clean energy technologies.

B. *Reconstruction and Relocation of Off-Road Distribution Lines*

Q. What is the Company proposing for off-road distribution line reconstruction and relocation as part of the GTEP?

A. The right-of-way initiative will focus on off-road line segments that are vulnerable to major storm events and constructed with outmoded equipment. Under this initiative, the Company will either rebuild off-road line segments within existing rights-of-way, or relocate them where feasible to areas along roadways. The program will make these vulnerable facilities more resilient to storm damage and will also improve the Company's ability to access to these facilities promoting faster restoration and less costly repairs. On the current system, anything that makes contact with these bare overhead lines will cause a customer interruption and will be difficult to resolve because the facilities are not located road-side.

The Company will identify and prioritize line segments for this work by examining reliability statistics, such as the locations of outages, trouble spots, length of outages and the like. The Company will also consider the asset condition, age of poles, size of the wires, and how the particular line segment and right-of-way fits into the total restoration effort, meaning whether it would be used on a regular basis to restore power to an area when the normal feed to that area has been taken out by some other event.

The base capital plan includes some investment for right-of-way reconstruction, but because of the benefits of this initiative the Company seeks to substantially ramp up this work beginning in 2020. Under the GTEP, PSNH has included $10 million for right-of-way hardening, which is approximately twice the investment contained in the base capital budget for this type of work.

Q. What is the Company proposing for overhead three-phase distribution line reconductoring as part of the GTEP?

A. PSNH proposes to accelerate this program by investing an incremental $5 million annually, which will enable the Company to complete an additional 10 miles of line upgrades per year. The total mileage competed in a given year will depend on whether the lines are relocated to roadside construction versus the rate for rebuild in the existing rights-of-way, depending on which is more cost-effective based on the exact circumstances of each line project. This additional investment will allow a substantial acceleration of this program.

Q. How will acceleration of these distribution line replacements make the system more flexible and resilient?

A. Although the program will improve reliability on blue sky days, the program will provide substantial benefits during major storm events that are more likely to cause falling trees and tree limbs. By removing a smaller diameter wood pole with bare wire and replacing it with a larger-diameter light-duty steel pole or a stronger Class 2 wood pole with covered conductor or spacer cable, the incidence of tree-related outages and the damage caused will be reduced. Also, the span distance between structures will be shorter than with the older open-wire construction, which increases the ability to withstand damage from falling trees. In addition, for lines that are relocated to roadside construction, the facilities are more accessible and will result in reduced outage times.

Q. What types of off-road lines will the Company target in this program?

A. Out of the 600 miles of right-of-way construction on the system, the Company will focus on the existing facilities with undersized bare conductor, which is more vulnerable to tree outages. However, the Company will not necessarily limit the program to undersized conductor, because all bare wire is more vulnerable to tree outages as compared to covered conductor. Also, in many instances, the option of relocating facilities to roadside construction will provide benefits irrespective of the existing conductor size.

Q. What is one of the overall benefits of rebuilding the overhead system for greater resiliency?

A. By replacing the overhead system with better materials, PSNH is preparing the grid to have a strong foundation to accommodate all of the advances and integrated energy solutions, including information along the grid and two-way power flows and distributed energy resources, which have the ability to use the grid for those efforts. If PSNH does not have a solid foundation for the system, it will not be able to accommodate these types of uses. With the current condition and construction of the system, the ability to interconnect advanced energy solutions is restricted in many areas of the system. The Company needs to have a system that is generally capable of interconnecting advanced energy solutions. Upgrading to newer, stronger infrastructure helps build a strong foundation for the distribution system, which will aid in the installation of advanced energy solutions.

The current composition of the predominantly open bare wire, Class 4 wooden pole system, in a heavily forested state with increasing storm activity presents reliability and resiliency challenges. The current construction standards of larger poles and covered wire result in a more resilient system that is also more flexible for integrating advanced energy solutions.

C. ***Substations***

Q. Does the Company's GTEP include a plan to accelerate the replacement of oil circuit breakers?

A. Yes. PSNH is including an incremental $2.5 million to enable it to perform an additional five replacements per year, for a total of nine per year. This will enable the Company to reduce the time for completion of this program by two years, from nine years to seven years.

Q. Why is it important to accelerate this program?

A. Based on the Company's experience from the base capital program, oil circuit breaker replacements provide an environmental benefit by eliminating the risk of leaks or discharge. These projects also result in reduced maintenance costs, improved safety for employees, and improved reliability in substation operations. New vacuum breakers are more reliable than older oil circuit breakers and do not have the environmental liability of oil-filled equipment.

D. ***Reporting***

Q. What type of reporting will the Company provide if the Commission approves the GTEP?

A. The Company anticipates providing annual reports to the Commission, similar to reports previously submitted for other distribution programs. On or about September 1 of each year, the Company would file a preliminary forecast of GTEP investments for the following calendar year and would discuss that plan with Commission staff. Next, on or about November 15 of each calendar year, and starting in 2020, PSNH will provide the Commission with a compliance filing that forecasts the Company's expected spending for GTEP investments for the upcoming calendar year. In addition, on an annual basis the Company will provide a revenue requirement calculation for the current calendar year consisting of actual capital spend to date and a forecast for the balance of the year, and a report to the Commission reconciling actual GTEP costs in the prior period, including a proposed reconciling adjustment to be made as part of the revenue requirement for the upcoming year.

Q. Please describe in further detail the type of information the Company will provide in its annual reconciliation filings.

A. These filings will include exhibits with information such as the investment summary by month for the preauthorized GTEP investments that were placed in service in the investment year; a summary view of capital additions categorized by plant account and investment category; and a summarized list of all GTEP investments placed in service. The annual filings and further information on the GTEP rate mechanism are provided in the testimony of Mr. Chung and Mr. Dixon.

Q. Is the spending within the GTEP program all capital?

A. The predominant portion is capital, but the program also includes incremental O&M associated with the completion of the resiliency projects, plus a modest amount of incremental non-labor O&M associated with the Westmoreland Clean Innovation Project. The program costs and cost-recovery are discussed in more detail in the testimony and exhibits of Mr. Chung and Mr. Dixon.

V. CONCLUSION

Q. Why should the Commission authorize the GTEP accelerated investments at this time?

A. The GTEP is a necessary, forward-looking program that will operate in concert with the Company's base capital program to provide critical support for accelerated investments targeted to fortify the distribution system with more resilient equipment and materials, while at the same time creating the operating platform necessary to enable the integration of advanced technology solutions on a cost effective and lasting basis. The GTEP will enable the Company to meet customer demand for a higher-level of service with a more resilient and flexible distribution system. The prevalence of older and outmoded equipment on the current system is substantial and PSNH must move forward to make meaningful progress to update and strengthen the system to meet these challenges.

Q. Do you have any concluding remarks?

A. PSNH takes the responsibility of providing safe and reliable service to its customers very seriously. This is illustrated in the transformational change that has been implemented in the organization, as well as the efficiencies derived through process changes and the use of technology. Reliable and resilient electric service will continue to be a societal focus in the future, and the Company appreciates the Commission's ongoing support of its efforts to improve the system and service to customers.

Q. Does this conclude your testimony?

A. Yes.