STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 24-070

REQUEST FOR CHANGE IN RATES

DIRECT TESTIMONY OF

Lavelle A. Freeman, Jennifer A. Schilling, Elli Ntakou,

Gerhard Walker, and Paul R. Renaud

Distribution System Planning and Solutions

On behalf of Public Service Company of New Hampshire

d/b/a Eversource Energy

June 11, 2024

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PETITION OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

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I. INTRODUCTION

Lavelle A. Freeman

Q. Please state your name, position, and business address.

A. My name is Lavelle A. Freeman. I am the Director of Distribution System Planning for Eversource Energy. My business address is 247 Station Ave, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in your position?

A. I am responsible for overseeing distribution system planning and distributed energy resource ("DER") interconnection activities in Eversource's service areas in Connecticut, Massachusetts and New Hampshire. In this proceeding, I am testifying on behalf of Public Service Company of New Hampshire ("PSNH" or the "Company").

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Electrical Engineering from the University of Alabama. Subsequently, I earned a Master of Science degree in Electrical Engineering with Power Systems concentration from the University of North Carolina at Charlotte and earned a Master of Science degree in Computer Engineering from North Carolina State University. I joined the IEEE Power Engineering Society while in graduate school and have been on the ANSI C84.1 Standard Committee since 2019.

I started my power systems career as an R&D Engineer at ABB Corporate Research in Raleigh, NC, where I devised innovative new products, algorithms and solutions to improve the value and efficiency of transmission and distribution product offerings within ABB Power T&D Inc. Thereafter, I joined the ABB Utility Consulting group in Raleigh, NC as a Senior Consulting Engineer where I performed system studies in distribution and transmission planning for utility customers, worked with customers to implement changes, and developed and supported power systems software applications that improved the efficiency, marketability, and cost-effectiveness of the group.

From 2003 to 2013, I was a Senior Engineer and then a Principal Engineer at General Electric Energy in Schenectady, NY, where I led consulting studies in distribution planning and analysis, power systems engineering, equipment applications, smart grid initiatives, and renewables impact and contributed to development of new products and technology for various General Electric Energy businesses. From 2013 to 2016, I was Manager of Transmission and Distribution at General Electric Energy Consulting where I directed a broad spectrum of client activities in the T&D space, with emphasis on power systems operation and planning, equipment application, renewables impact, and systems analysis. From 2016 through 2020, I was Technical Director at General Electric Energy Consulting in Schenectady, NY. In this position, I led project teams and developed business opportunities in the distribution space with emphasis on DER integration, microgrid design, grid modernization, reliability, power quality, and resiliency. I developed and led execution of over $5M in distribution-related projects in New York, New Jersey, and Massachusetts. I also successfully completed four ground-breaking New York Prize Stage 2 microgrid design projects and managed the peer research consortium working extensively with distribution planners and engineers in investor-owned, municipal and cooperative utilities all across the country. In 2020, I joined Eversource Energy as Director, Distribution System Planning.

Q. Have you previously testified before the New Hampshire Public Utilities Commission (“Commission”)?

A. Yes, I have testified before the Commission in the Company’s Least Cost Integrated Resource Planning proceeding (Docket No. DE-20-161).

Q. Have you previously testified before any other regulatory body?

A. Yes, I have testified before the Massachusetts Department of Public Utilities and the Connecticut Public Utilities Regulatory Authority numerous times, including base distribution rate proceedings for the Company’s affiliates.

Jennifer A. Schilling

Q. Please state your name, position, and business address.

A. My name is Jennifer A. Schilling. I am Vice President of Grid Modernization for Eversource Energy. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in your position?

A. As Vice President of Grid Modernization, I am responsible for the Company's grid modernization development, as well as developing strategies to increase the capacity of the Company's distribution system to optimize the integration of DERs, while improving the safety, security, reliability, and cost-effectiveness of the system.

Q. Please describe your educational background and professional experience.

A. I graduated with a Bachelor of Arts degree in environmental science and political Science from Barnard College, Columbia University in 1995. In 2001, I earned a Master of Business Administration from Duke University. From 2001 to 2008, I held several positions at Reliant Energy in Houston Texas, ending my tenure in the position of Director, Corporate Strategy. In 2008, I joined the Northeast Utilities System as the Director of Business Planning for Western Massachusetts Electric Company ("WMECO"). I subsequently accepted the role of Director, Asset Management for WMECO and then Director, Distribution Engineering for Eversource, prior to assuming my current role.

Q. Have you previously testified before the Commission?

A. Yes, I have testified before the Commission in the Company's most recent base distribution rate case, Docket No. DE 19-057.

Q. Have you previously testified before any other regulatory body?

A. Yes, I have testified before the Massachusetts Department of Public Utilities numerous times, including in support of the Company's affiliate's grid modernization plan (D.P.U. 21-80 and electric sector modernization plan (D.P.U. 24-10).

Elli Ntakou

Q. Please state your name, position, and business address.

A. My name is Elli Ntakou. I am Manager of System Resiliency and Reliability at Eversource Energy. My business address is 247 Station Drive, Westwood, MA 02090.

Q. What are your principal responsibilities in your position?

A. As the Manager of System Resilience and Reliability Planning, I am responsible for Eversource's reliability and resilience programs for its electrical infrastructure. The Company's efforts focus on assessing a wide portfolio of reliability and resilience solutions and prioritizing, optimizing, and granularly targeting these solutions to its transmission and distribution grid needs to be based on historical data, data forecasts, and engineering models.

Q. Please describe your educational background and professional experience.

A. I graduated from Boston University College of Engineering with a Master of Science and a PhD, both in Systems Engineering. Subsequently, I worked for ESAI Power LLC, leading their Northeast wholesale power market modeling efforts. From 2018 to July 2022, I was employed by Quanta Technology, in various positions, most recently as Senior Advisor. As part of my role, I advised a breadth of clients in the power sector on various topics including resilience and reliability, non-wires alternatives, storage use-cases and integration, grid modernization and scenario planning. In July 2022, I joined Eversource as the Manager of System Resilience and Reliability Planning.

Q. Have you previously testified before the Commission

A. Yes, I have previously provided testimony to the Commission in Docket No. DE-23-021.

Q. Have you previously testified before any other regulatory body?

A. Yes, I have testified before the Massachusetts Department of Public Utilities numerous times, including in support of the Company's affiliate's electric sector modernization plan (D.P.U. 24-10).

Gerhard Walker

Q. Please state your name, position, and business address.

A. My name is Gerhard Walker. I am Manager for Advanced Forecasting and Modeling for Eversource Energy and its operating companies, including PSNH. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in your position?

A. As the Manager for Advanced Forecasting and Modeling, I oversee the Company's system planning forecasts. The Company's efforts focus on the development of forecasts that provide short- and long-term visibility. I further oversee System Plannings Non-Wires Alternatives Framework and Modeling Capabilities and the Company's integrated energy planning efforts.

Q. Please describe your educational background and professional experience.

A. I hold a Doctorate in electrical engineering from University of Stuttgart, Germany. I began my career in 2013 at the Netze BW, Germany's third largest distribution system operator. While at Netze BW, I led research and development efforts into probabilistic forecasting, advanced system planning, and electric vehicle grid integration. Additionally, I oversaw efforts with the Association of German Energy and Water Industries to align DSO objectives with the automotive industry on issues regarding charge specifications and load management, as well as ELT coordination across all Netze BW subsidiaries on grid modification topics. In 2016, I joined General Electric

Current as the Director for Grid Solutions in Boston, to develop distribution use cases for virtual power plant aggregation of DERs. In 2017, I became the Director for Product Management at Opus One Solutions, a Canadian Utility Software supplier, where I led the scaling up of software solutions and successful customer acquisitions including HECO, SCE, Ameren, as well as expansions into the UK and Germany. I joined Eversource Energy in 2020 as a Principal Engineer in System Planning.

Q. Have you previously testified before the Commission?

A. Yes, I have testified before the Commission in the Company's Least Cost Integrated Resource Planning proceeding (Docket No. DE-20-161).

Q. Have you previously testified before any other regulatory body?

A. Yes, I have testified before the Massachusetts Department of Public Utilities numerous times, including in support of the Company's affiliate's base distribution rate case (D.P.U. 22-22) and its electric sector modernization plan (D.P.U. 24-10).

Paul R. Renaud

Q. Please state your full name and business address.

A. My name is Paul R. Renaud. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. By whom are you employed and in what capacity?

A. I am the Vice President of Engineering for ESC, which provides centralized corporate, financial and engineering services to the operating subsidiaries of Eversource Energy. In this position, I am currently responsible for distribution engineering and design, single pole administration and distribution network and underground systems engineering for Eversource Energy's operating utility subsidiaries in Massachusetts and New Hampshire, including PSNH.

Q. Please briefly summarize your educational background and business experience.

A. I graduated from the University of Bridgeport in Bridgeport, Connecticut with a Bachelor of Science Degree in Electrical Engineering. I subsequently received a Master of Science Electrical Engineering, Power Systems degree from Northeastern University in Boston, Massachusetts. I am a registered Professional Engineer in the State of Massachusetts. From 2000 through 2011, I worked for National Grid USA in Waltham, Massachusetts, where I held lead engineering roles for Transmission Market Development and Transmission Regulation and Policy areas in 2001 through 2004. In 2005, I became the Manager for Transmission Asset Strategy and in 2008 through 2011 held the position of Vice President of Transmission Asset Management and managed the company's transmission assets in New York and New England. Beginning in 2011, I worked for Vermont Electric Power Company, where I served as Director of System Planning, Engineering, and Telecommunication. I provided strategic and day-to-day direction on all engineering and planning activities related to Vermont's high voltage transmission system. In March 2014, I was hired by Eversource (then Northeast Utilities) as Vice President of Massachusetts Engineering. In 2018, I accepted the position as Vice President, Engineering, for the Eversource Energy electric operating subsidiaries in Connecticut, Massachusetts and New Hampshire.

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

A. No, I have not previously testified before the Commission.

Q. Have you previously testified before any other regulatory body?

A. Yes. I have sponsored testimony before the Massachusetts Department of Public Utilities in several proceedings including NSTAR Electric Company's 2017 and 2022 base distribution rate proceedings.

Q. What is the purpose of this joint testimony?

A. This joint testimony presents an illustration of the Company's comprehensive forecasting and planning process to position the PSNH transmission and distribution system to meet the needs of customers both from a reliability and resiliency perspective. The aging infrastructure, regional customer growth, and adoption of DERs and electric vehicles, will require significant upgrades in substations, distribution and transmission lines necessary to support customer demand over the long term. In that regard, this testimony and the attached Distribution Solutions Plan ("DSP") is designed to provide insight into the Company's analytical approach to assess total demand and system need over the next ten years.

Second, this testimony also presents the Company's projected capital budget for the period 2025-2029. As discussed in the Joint Testimony of Douglas W. Foley, Robert S. Coates, Jr. and Douglas P. Horton ("Case Overview Testimony"), the projected capital budget is used to establish the annual cap on capital additions included in the annual K-bar adjustment under the proposed Performance Based Ratemaking ("PBR") plan.

Q. Are you sponsoring any attachments through your testimony?

A. Yes. We are jointly supporting the Company's DSP (Attachment ES-DSP-1).

Q. How is your testimony organized?

A. Section I of this testimony is the introduction. Section II provides an overview of the Company's DSP. Section III provides an overview of the current state of the distribution system. Section IV provides a summary of the Company's demand forecasting process and results. Section V provides an overview of the Company's project planning standards and process. Section VI provides an overview of the Company's proposed capital and grid enhancement proposals. Section VII is the conclusion.

II. DISTRIBUTION SOLUTIONS PLAN ("DSP")

Q. Please discuss the purpose of the DSP

A. The Company is committed to providing safe, reliable, resilient, and cost-efficient electric service to New Hampshire customers. In furtherance of that objective, the DSP provides a comprehensive discussion of the current state of the Company's distribution system; the forecast of system demand over the next ten years; and a summary of the Company's solutions to address system needs. In recognition of the importance that electricity has in the daily lives of customers (both residential and business), the DSP sets forth the Company's analysis and approach to the replacement and upgrade of aging infrastructure to support reliability and infrastructure development to address increasing localized demand due to population growth, economic development and electrification. The DSP is also designed to maintain safe and reliable service at a measured pace of investment and to develop targeted investments to address extreme weather impacts that are becoming more prevalent.

Q. Please provide an overview of the DSP.

A. Section 1 of the DSP is an executive summary and highlights the key areas of investment that the Company must undertake to continue to deliver safe and reliable electric service to customers. Section 2 presents an overview of the current state of the distribution system, including the challenges the Company must address. In Section 2, the Company also provides a region-by-region summary of capacity and reliability issues. The distribution planning process is described in Section 3 of the DSP. This section includes an overview of the integrated planning process, the bulk substation capacity planning process, substation asset condition assessments, as well as distribution feeder capacity, reliability, and resiliency tools, process, standards, and criteria. As discussed above, Section 4 provides an overview of the Company's 5- and 10-year demand forecast.

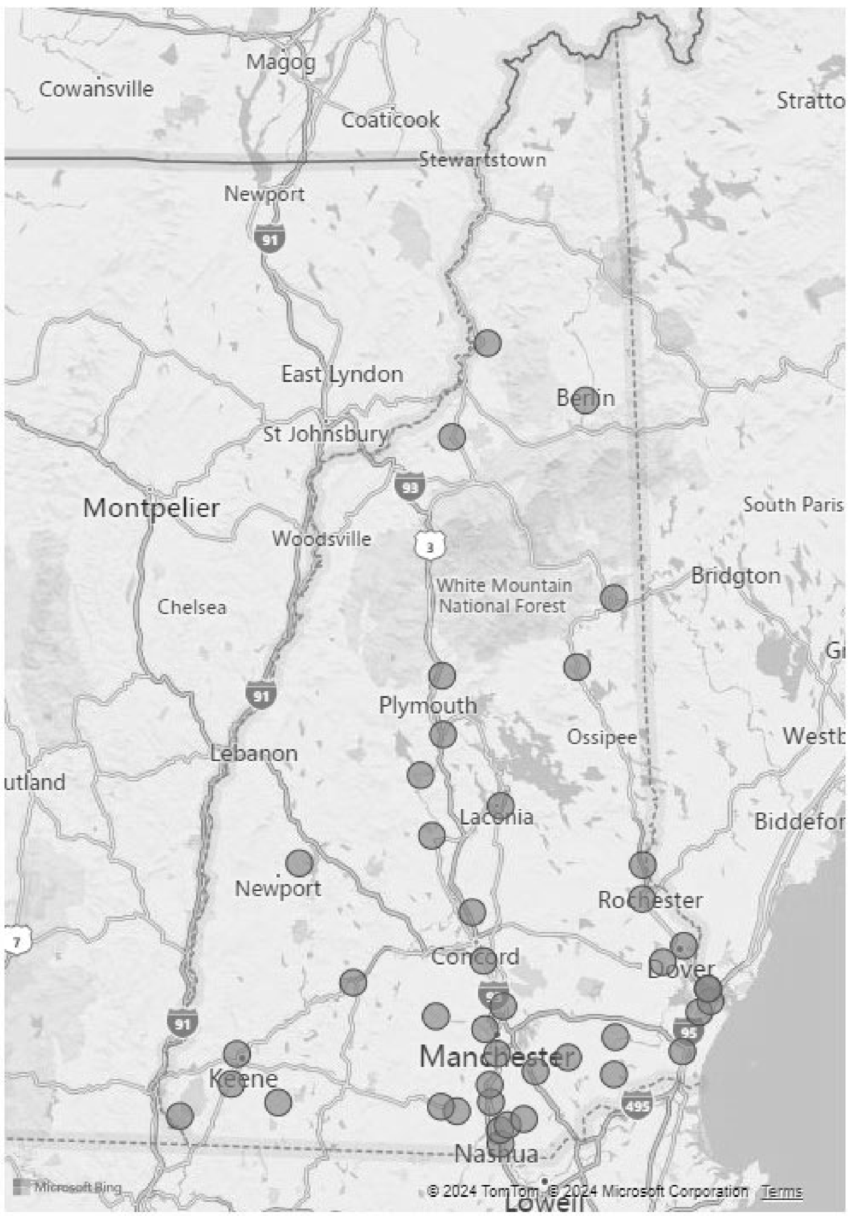
In Section 5, the Company discusses the planning solutions to address the capacity, aging infrastructure, and reliability challenges discussed in the DSP. This section also includes a discussion of proposed grid modernization, Company-owned solar, resiliency, and co-optimized reliability enhancements that, with the Commission's authorization, could be implemented in the next five years to provide enhanced benefits to customers and modernize the PSNH distribution system to provide safe, reliable, and cost-efficient service while meeting the evolving needs of customers. The Company's five-year capital budget is summarized in Section 6. This section also describes the customer benefits that will be achieved under the Company's five-year investment plan. All investment plans include a level of uncertainty, which the Company also discusses in Section 6. Section 7 is the DSP conclusion and Section 8 is the Appendix, which includes a Glossary, list of acronyms, historical substation loads, and a reference table of figures and tables included in the DSP.

III. CURRENT STATE OF THE SYSTEM

Q. What is the state of the current distribution system?

A. The current state of the distribution system reflects an ongoing evolution from a stable system that relied on centralized generation to a more dynamic grid that integrates distributed energy resources such as generation from solar and wind, grid-scale energy storage, flexible loads and demand response, as well as increased electric demand, new technologies like electric vehicles, and higher requirements for reliable and resilient service. As discussed in more detail in Section 2 of the DSP, the Company has delivered overall consistent reliable service based on System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) metrics. In addition, the Company has implemented distribution automation devices and TripSavers to drive improved reliability. Despite this success from recent system improvements, there are still many challenges that are inherent to an aging, overhead distribution system, with long radial feeders operating at multiple voltages over difficult terrain and traversing through heavily treed areas, especially in light of progressing climate change and associated weather events. Several circuits have limited fault current availability making them difficult to sectionalize, and many distribution assets are nearing the end of useful life.

Today, the Company is the primary electric provider for 211 towns and cities, covering approximately 5,630 square miles across New Hampshire. The Company provides service to approximately 539,000 customer accounts. Across the five planning regions, the 50 bulk distribution substations shown in the below map serve customers residing in an average area of almost 200 square miles per substation.



The distribution system includes a total of 123 substations (including the 50 bulk distribution substations discussed above) with an aggregate nameplate capacity of 3.9 GW, as well as 186 substation transformers, 12,300 circuit miles of overhead lines, 2,100 circuit miles of underground lines, and 287,900 service transformers. Of the 186 substation transformers, almost 70% are greater than 20 years old, and 15% are older than 60 years. Of the 475 distribution station breakers currently serving PSNH customers, over 75% are older than 10 years old, and 12% are over 50 years old.

For much of the last decade, peak load throughout New Hampshire has generally been flat as economic growth was offset by two primary load-reduction drivers: (1) the energy efficiency programs run by the Company and (2) adoption of solar. The NHSaves program efforts are primarily focused on reducing load on the electric and natural gas distribution systems. The current 2024-2026 plan expands the prior active demand response pilots into full programs with larger budgets to further target load curtailment during the ISO-NE system peak.

System-wide economic growth continues to be offset by energy efficiency and solar. However, more recently, localized economic and customer growth has outpaced the achievable energy efficiency reductions and some areas are experiencing capacity constraints at substations and transformers. Additionally, New Hampshire is beginning to experience increases in electrification of heating and transportation sectors. In 2023, the state saw a 3,487 increase in electric vehicles. Over the next few decades, the

Company anticipates that the state will see further increases in electric vehicle adoption. This is especially true for electric vehicle charging to meet the needs of travelers visiting the state from neighboring jurisdictions.

Considering aggregate demand from these various sources, available capacity in certain areas of the existing network has already been maximized. As shown in Section 8.2 of the DSP, seven substations are currently at or near maximum capacity.

During the past few years, the Company has taken several steps to modernize its system to ensure safe and reliable service. The Distribution Automation program and associated telecom network is the foundational layer of remote control and monitoring that is used by control room operators to operate the distribution system safely, reliably, and optimally. This network of field devices consists of over 1,900 "smart" switches. These devices provide status and measurement information of the distribution grid. In the past 10 years, 10 new radio towers were built and commissioned. These towers increase the data radio coverage by 200 percent. In addition, a standard equipment design for the use of cellular communications was also established. This provided an additional option for areas where radio coverage was not sufficient. However, the communications network continues to have a need to ensure that proper coverage, reliability, and data throughput are available for the field devices that are required to operate the grid safely, reliably, and optimally.

The Company is utilizing advances in technology to build and operate a smarter, flexible, and resilient grid. The changing nature of the grid with increased automation driving operational complexity requires new approaches. The new technologies the Company is investing in provide improvements in (1) visibility and situational awareness; (2) automated reconfiguration; (3) voltage management; (4) storm response; (5) asset management; and (6) data analytics.

Q. What are the challenges that the current distribution system faces?

A. While investments to maintain the network to ensure the safe and reliable operation of the Company's existing assets continue to be made, the need for such investments is increasing. The Company has identified challenges discussed in the DSP. Some of the challenges include:

- **Aging infrastructure:** Aging equipment, such as transformers, switchgear, conductor, cables, insulators, and related ancillary equipment, can lead to decreased reliability, safety risks, reduced capacity, and lower system efficiency as their condition worsens.
- **Voltage regulation/Power quality:** Maintaining appropriate voltage levels and power quality is crucial for the distribution grid's reliable and efficient operation. High load conditions can cause voltage to decrease, and high concentrations of generation can cause voltage to increase. Introducing generation throughout the distribution system, particularly intermittent

generation (e.g., solar, wind), impacts the voltage profile and power quality often in unpredictable ways.

- **Connecting renewables:** Continued investment in the Company's distribution infrastructure is necessary to ensure that DERs can be safely and reliably connected and operated to handle reverse power flow from the distribution to transmission system.
- **Pockets of Significant Customer Growth**: Migration of customers into the Eastern, Southern, and Central regions of New Hampshire has resulted in significant new construction and step loads on the system, requiring the need to buildout and upgrade infrastructure.
- **Increased load from electrifying heat and transportation:** The growth in electricity consumption from electric transport and heating will impact the system over time, potentially leading to overloading in certain areas. Overloading can cause asset damage, premature aging of assets, and the inability to manage contingencies, leading to reliability issues.
- **Increasing resilience:** The more frequent and severe weather events, like high winds, snowstorms, icing events, and river and coastal flooding, as well as more extreme temperature days, all pose risks to grid infrastructure and customer service.

IV. DEMAND FORECAST

Q. What is the purpose of the 5- and 10-year electric demand forecast?

A. The five- and ten-year electric demand forecast described in Section 4 of the DSP (Att. ES-DSP-1) is a critical input into the distribution planning process. The basic goal of planning is to provide orderly expansion of the equipment and facilities to meet future system demand with acceptable system performance – prior to reliability issues arising. The key objectives include building sufficient infrastructure capacity and technology capabilities to meet instantaneous demand and manage instantaneous demand to be sufficiently below the infrastructure equipment capacity acceptable limits; satisfy power quality/voltage requirement within applicable limits; provide adequate availability to meet customer requirements; and deliver power with required frequency.

Effective planning accounts for lead time to deploy distribution assets in developing solutions for performance requirements. In other words, we need to plan because it takes time to build capacity on the system. Currently, it can take more than ten years to build transmission, and well over five years to place a bulk distribution substation in service. This includes time required to: perform field audits and environmental evaluation; develop engineering designs and cost estimates; procure equipment (current lead time for power transformers and switchgear is over two years); and obtain siting/permitting approvals. Given these construction lead times, the Company must conduct a 5- and 10-year forecast to ensure projects are initiated in a timely manner so as to be in-service by the time of need. Said differently, if the Company fails to ensure sufficient capacity is available to meet the 10-year forecast, considering all applicable timelines, this can result in system capacity deficits, equipment overloads, and loss of service to customers in the future.

Q. What are the main components of the 5- and 10-year electric demand forecast?

A. The 5- and 10-year forecast is comprised of four load growth components, two load reducing components, and battery storage systems. The four load growth components are the underlying trend load, load growth that is uniformly spread across the system relative to the economic development of each region. Added to the trend load, electric vehicles are considered with their on peak charging contributions, as well as step loads, or large, new customer additions, such as factories, residential developments, or high voltage fast chargers. Lastly, the Company forecasts building heating electrification. However, until the system is winter peaking, heating electrification does not contribute to the peak load and as such, is not yet reflected in the Company's 10-year forecasted peak. Depending on customer load make up in a given region, heating electrification through heat pumps can add to summer loads as whole house cooling is introduced. Modeling these impacts is critically important to providing long term reliable service. Reductions of the load forecast are driven by impacts from the Company's energy efficiency programs, as well as firm reductions of the peak load at time of peak driven by distributed solar, both ground-mounted and rooftop installed. Storage systems are also forecasted, both standalone and co-sited with solar, for the 5- and 10-year forecast.

Q. Which of the components of the 5- and 10-year electric demand forecast drive demand growth?

A. The key driver of gross demand increase in the 5- and 10-year forecast is about 49 MW of step loads, which almost exclusively appear in the Eastern and Southern regions, driven by increases in customer load in the population centers of the Merrimack River Valley (Manchester and Nashua) and in the Seacoast region (Portsmouth, Dover, and Rochester). Step loads represent large, new load additions to the Company's substations which the Company has direct customer information on, and for which it has received load letters. These step loads can include new commercial and industrial ("C&I") development, upgrades to existing customer sites, large multi-unit residential developments, battery storage, or electric vehicle charging. As discussed in Section 5.1.1 of the DSP, all station upgrades considered by the Company to address load constraints are driven directly by confirmed and certain step loads, as fulfillment of direct customer requests are the priority. The Company also forecasted 12 MW of potential residential electric vehicle charging across all regions consistent with the system peak. However, the electric vehicle loads are significantly more evenly spread across the territory and as a result, from a local distribution system impact perspective, are less acute in driving demand growth at a bulk station level compared to the step loads.

Q. Please explain the process around developing the 5- and 10-year electric demand forecast.

A. Consistent with the Company's typical electric demand forecast methodology, the first step in each forecasting cycle is an assessment of net station peaks at each distribution bulk station in the Company's territory. The Company commences its forecasting process annually during the summer peak month where it monitors station peaks across all bulk substations and records these net peaks (i.e., demand that is actually measured).

The second step is to disaggregate the net station peak to separate out historical gross load peak and the historical impact of solar, switching operations, weather conditions, or other factors which might have contributed to a higher, or lower, net station reading. Over the last 15 years, net peaks have been relatively flat to declining because the impacts of energy efficiency and photovoltaics ("PV") have offset underlying customer demand growth from new customers and economic growth. This effect has caused net peaks to have consistently shifted to later in the day where solar offset is less pronounced. If only the net demand were modeled, as opposed to gross load, the Company's modeling would miss the nuances of the effects of baseload and the various DERs, and the Company would be less able to project the effects on net demand of changes in customer growth or DER penetration going forward.

Once the historical gross load peak is determined, a weather normalized trend load forecast is created which utilizes a 90/10 weather assumption on a three-day rolling weighted temperature humidity index ("THI"). This ensures that forecasted load reflects possible extremely hot and humid weather events and consequently ensures sufficient system capacity to serve customers during such conditions.

The Company then corrects this forecast for all known step loads which are ranked by certainty of the projects coming to fruition. For electric vehicles, travel and mobility data is collected at a zip code level and aggregated to bulk stations to provide station by station specific charging profiles for light duty electric vehicles ("LDV"). Medium-duty ("MDV") and heavy-duty vehicles ("HDV") are tracked through the step load process. Energy efficiency impacts are modeled based on currently approved energy efficiency programs. Demand response and behind the meter storage systems that consistently deliver peak demand reductions are captured in the trend forecast as they impact the recorded peaks and are therefore not separately modeled. Installed solar capacity is projected for both ground mounted and rooftop solar. PV generation (hourly solar output) is modeled using satellite-based irradiance data in combination with a probabilistic weather model to ascertain firm solar contributions to peak load. Once the forecast is completed in March of the following year, it is issued to the planning departments to conduct a review of all stations and projects based on the new forecast data.

In summary, each substation's peak load forecast is a function of the substation's historical peaks and the relevant service territory peak load history and forecast. Adjustments are made to individual substation forecasts for: (1) specific, identified large development projects and expected changes in system configuration or operation that could not otherwise be predicted by the Company's econometric forecasts or an individual substation's share of those forecasts; (2) Company sponsored energy efficiency and PV installations which decrease the forecast; and (3) future electric vehicle charging which increase the forecast. The result of these adjustments yields the weather normalized, 90/10 net station peak load forecast.

Q. Did the Company conduct any sensitivity analysis in the 5- and 10-year electric demand forecast? If not, please explain the Company's rationale.

A. No, the purpose of the 5- and 10-year forecast is to provide the Company with a capacity need assessment of its system that it can use to authorize and prioritize capital projects. As a result, the Company considers only the 90/10 net station load forecast with all its adjustments for electric vehicles, PV generation, Company-sponsored energy efficiency and step loads (for which it considers only those projects that are "certain" or have high confidence). Given project timelines for bulk stations range between 5-10 years, assessing sensitivities are not conducive to the process as they introduce unnecessary uncertainty in the short term. Further, the uncertainties in the forecast are minimal as all information is either based on known projects or state-approved programs. The Company selects a single demand scenario upon which it acts to ensure that imminently needed upgrades can be constructed in time to ensure reliable service for its customers.

Q. Did the Company account for load growth in its forecast?

A. Yes. The Company builds a 10-year econometric model based on the past 10 years of station peaks with 90/10 weather normalization and future economic indicators. This trend forecast reflects the growth of the underpinning load on the system today and load growth relative to the development of the economy. However, some load growth appears very localized and cannot be accurately spread across the system. The Company therefore incorporates projected new load additions, or step loads (typically representing single load increases of 500 kW or more such as new commercial and industrial development, upgrades to existing sites, large multi-unit residential developments, electrification, grid charging battery energy storage systems ("ESS"), and electric vehicle charging), to the Company's substations forecast.

The Company also accounts for load growth from electric vehicles, including light, medium, and heavy-duty vehicles. Light duty vehicles are accounted for in the 10-year forecast using an adoption model in line with the state policy and mobility data, while medium- and heavy-duty vehicles vehicle charging, as well as HVDC charging stations for light duty vehicles, are tracked, and accounted for through the step load tracking process as these loads are significantly more localized and require a greater degree of certainty. Additionally, the Company accounts for load growth from heating electrification across its system. The Company has the ability to make local adjustments for municipalities that accelerate the deployment of electric vehicles, heat pumps, or solar installations in a specific region. In all cases, the Company assumes full compliance with local laws, building codes, and ordinances, especially when new loads are introduced into the system.

Q. How did the Company account for large load or step loads in its forecast?

A. Typically, the Company will track projected incremental load increases at a bulk station level starting at the 500-kW threshold, depending on if the load addition is associated with a distribution non bulk station or a bulk substation. The challenge with step loads is that they are relatively large compared to other forecast components. Specifically for the Company in New Hampshire, step loads make up the majority of the gross forecast system-wide, and in the Eastern and Southern regions the percentage is significantly higher.

The Company acquires this information through detailed coordination with its national and strategic accounts and their respective customer representatives within the Company. Because these loads are driven directly by customer decisions, the Company is heavily reliant on customer-provided information to accurately model the impact on forecasted demand, both in terms of timing and magnitude. The majority of this engagement is handled by the Company's Strategic and National Account Executives to get an early indication of customer development plans, as well as the Company's Distribution Engineering teams who review the capacity requirements.

Step loads are the primary driver for substation capital investments undertaken by the Company, which in turn exposes the Company's capital plan to the risk of changes to the developer projects – a canceled project could mean a substation upgrade is no longer needed in the near-term, or a last-minute change to add significant load can pull a substation need to earlier than the Company can feasibly build requisite infrastructure. Step loads are categorized based on the level of certainty as follows:

- Certain: A work order signed, and payment has been received.
- Probable: Public statements have been made and permits requested, or other actions have announced the customers intention to the broader public making a withdrawal less likely.
- Possible: Customer is engaging with PSNH in earnest discussions about the project, distribution engineering is included, and some public statements have been made.
- Uncertain: Discussions happen only with strategic and national accounts and at a conceptual level.
- Forecasted: Assumed load potential based on state or local electrification objectives and customer goals.

The step load tracking process is updated as projects arise and are incorporated into the Company's forecasts on a yearly basis. Currently, only loads that are "Certain" are included in the forecast; taken at 100% of rated capacity (or other capacity as indicated by the customer) and expected to be online by their PTO ("permission to operate") date (usually in 2-3 years) to minimize the risk of projects dropping from the queue and requiring changes to the Company's capital plan.

Q. How did the Company account for heating electrification in the forecast?

A. The Company monitors the development of the electric heating market in New Hampshire. In addition, the Company is seeking advanced forecasting capabilities to model adoption curves in greater local detail. While the Company reviews electric heating as part of the 5- and 10- year forecast, the forecasted electric heating load in the 10-year horizon is not expected to be sufficient to make the winter peak surpass the summer peak. As a result, all peak forecast values described in the DSP and this testimony for the 5- and 10-year forecast are for summer peak only, and do not include an electric heating component.

Q. How did the Company account for electric vehicle charging in its forecast?

A. The Company analyzes: (1) system-level electric vehicle adoption; (2) conversion of internal combustions vehicles to electric vehicles; and (3) charging profiles and locations.

The Company utilizes mobility data in a travel model to determine the time during a day when electric vehicle charging is likely to coincide with the peak. The travel model uses advanced data analytics and GPS tracking data from cellular service and App providers to create travel profiles showing when, how many, and where vehicles terminate a trip. This then allows the creation of charging profiles for the Company with temporal and spatial resolution. One important consideration is that this is done by season (Winter, Spring, Summer and Fall) and day type (Weekdays (Monday-Thursday), Fridays, Weekend Days (Saturday-Sunday), and Holidays) to capture dynamics such as weekend and holiday travel.

These travel profiles, and the resulting charging profiles can be created at a zip-code level and then aggregated up to a substation, resulting in unique charging profiles by substation, based on the different customers and needs of the customers the station services.

Q. Did the Company account for technologies and programs that reduce electric demand in its forecast?

A. Yes. As discussed in Section 4.2 of the DSP, the Company's forecast incorporates reductions in peak demand from energy efficiency and distributed PV generation. The Company also forecasts storage adoption in the 5- and 10-year forecast. The Company's forecasting methodology includes all behind-the-meter (BTM) ESS that consistently (over multiple years) impact the station peaks and as such includes these storage systems in the forecast. The Company does not attribute any load reduction to co-sited or stand-alone front-of-the-meter (FTM) ESS as there are currently no mechanisms in place that would give the Company operational control over third party systems. Instead, large scale standalone and co-sited ESS are treated as step loads in the forecast if their interconnection agreement allows the system to charge during peak hours (see Section 4.2.6 of the DSP for a discussion of ESS).

Q. What are the key takeaways from the 5- and 10-year forecast and the planning implications for Eversource?

A. The Company's 5- and 10-year forecast shows significant load growth in population centers in the Eastern and Southern planning regions. In these regions, the Company may need to upgrade 4 substations driven by step loads. In addition to substation upgrades, more localized load growth will require distribution circuit capacity upgrades discussed in Section 5.1.2 of the DSP. In the Central region, pockets of new residential and C&I load growth due to migration from Massachusetts are resulting in overloaded step transformers and distribution substation transformers. Similar to the Central region, the Eastern region is also experiencing customer growth, as well as the challenges of aging infrastructure. In particular, in the Pease area rapid C&I load growth continues from the development of the pharmaceutical industry. Large towns with historic 4.16 kV systems require conversion to 12 kV, and some even require conversion to 34.5 kV systems. The Southern region is experiencing similar customer growth with pockets of new residential complexes, retail facilities, and warehouses along the Evergreen Parkway and I-93 Corridor, resulting in overladed step transformers and distribution substation transformers and requiring upgrades to higher distribution voltages.

In the Northern and Western regions, the load profile used to include vacation campsites that are transitioning to vacation homes, such as in the Lake Sunapee area. These regions also continue to experience substantial load demand from ski resorts and industrial load centers served by long radial circuits that can be severely impacted by lack of electrical strength and low short circuit fault currents. The town areas are served by overhead step transformers which are at or near overload conditions and downtown systems are near end of life.

In summary, the demand forecast projects in pockets of the state that will require significant system upgrades due to localized capacity constraints, even though the service territory as a whole is experiencing relatively limited load growth. As discussed further in Section 5.2, the Company must also undertake significant infrastructure upgrades in local areas to address reliability conditions and aging infrastructure.

V. PROJECT PLANNING STANDARDS AND PROCESS

Q. Would you describe the Company's electrical power system planning criteria standards?

A. The Company's Electric Power System ("EPS") Planning Criteria and Standards provide a consistent uniform approach to designing an efficient and reliable electric transmission and distribution system that provides the quality of service expected by our customers. As a regulated utility, the Company has an obligation to provide reliable service in accordance with applicable safety codes and regulatory requirements. The basic goal is to provide orderly, economic expansion of equipment and facilities to meet future system demand with acceptable system performance. The key objectives include to: build sufficient capacity to meet instantaneous demand; satisfy power quality/voltage requirements within applicable standards; provide adequate availability to meet customer requirements; and deliver power with the required frequency.

To meet these objectives, the transmission system is designed in accordance with NERC reliability standards, NPCC regional standards, and ISO-NE planning procedures. At the distribution level, the Company's Distribution System Planning

Guide ("DSPG"), along with reference procedure SYSPLAN-010 (Bulk Distribution Substation Assessment), establishes the Company's criteria and guidelines for the planning and design of its bulk substation and electric distribution facilities. The Company must also comply with planning standards SYSPLAN-001 and SYSPLAN-015 (transmission system deficiencies) and mitigate the consequences of the N-1 and N-1-1 contingencies.

The scope of the Distribution System Planning Guide is comprehensive, including traditional planning considerations for expanding the system to avoid capacity, voltage, and reliability violations as well as advanced integrated planning concepts related to non-wires alternatives ("NWA"), ESS, other DER applications and probabilistic load/DER evaluation with electric vehicle adoption.

Q. Would you please describe the Company's bulk substation planning criteria?

A. At the distribution level, it is the Company's goal to have customer electric service automatically restored upon loss of supply to Bulk Distribution Supply Buses. In high load density areas, a higher degree of reliability is ensured by maintaining supply, without the loss of power, to Bulk Distribution Buses following an N-1 Contingency Condition.

The Company's Bulk Distribution Substation Assessment Procedure, SYSPLAN-010 and the DSPG established the Company's criteria and guidelines for the planning and design of its bulk substation and distribution facilities, and sets forth the various reliability criteria by which the capacity and reliability performance of the Company's supply systems are gauged, and how these assessments are conducted. SYSPLAN-010 states that plans need to be developed to ensure that:

- Each distribution bus has at least two means of supply (primary and secondary).
- Upon loss of a source of supply, customer electric service is automatically restored.
- The number of bulk distribution buses with no power source because of a single contingency is minimized.

In the performance of system planning studies to establish the need for system upgrades, the Company employs detailed steady-state and dynamic electrical models of its transmission, substation and distribution systems using various tools, including PSS/E (Power System Simulator for Engineering) for transmission load flow and stability assessment, Synergi Electric for distribution analysis including DER impact, and PSCAD (Power Systems Computer Aided Design), for Electromagnetic Transients (EMT) analysis. The planning standards set forth in SYSPLAN-010 are those employed in the Company's overall assessment of its system.

In accordance with the planning standards set forth in the DSPG, under normal operating conditions and configurations (N-0), substation transformer loads should not exceed 75% of the normal rating and substation transformers; and under N-1 emergency conditions involving loss of a bulk transformer, loads for remaining substation transformers should not exceed their LTE rating after implementation of the automatic bus restoral ("ABR") scheme. When actual or projected transformer loads approach 95% of the normal rating (under normal operating conditions), there are two primary options available: (1) permanently transfer loads to other substations in the area, or (2) provide additional transformer capacity by installing a larger transformer, or additional transformers in the area.

Q. Would you please describe the Company's planning criteria for feeders and lines?

A. The DSPG also states the criteria for designing and upgrading distribution feeders. There are different criteria for the feeders serving underground ("UG") facilities, feeders serving overhead ("OH") facilities, feeders supplying UG network systems, and distribution supply system ("DSS") lines that function like transmission lines (to transfer load between stations), but at the distribution voltage level. The criteria dictate the percentage loading at which each category of feeder should be maintained.

As noted above, the DSPG and SYSPLAN-010 also define the planning criteria for NWA solutions and the use of ESS. The Company evaluates NWA solutions as alternatives to traditional distribution upgrade solutions and incorporates those alternatives where they meet suitability criteria, are technically viable, and justifiable on a benefit-cost basis.

Q. Please describe the Company's capital planning process, and decision-making process for distribution system capital investments.

A. The Company's planning and decision-making process is discussed in Chapter 3 of the DSP. As part of the Company's Capital Planning process, the near-term forecast informs capital planning for substation projects and helps prioritize investments based on immediate need. This is necessary to ensure that any proposed solution will be suitable to meet the near-term load.

Based on the system analysis results, the Company's planning engineers design and implement a variety of projects to resolve thermal/capacity, power quality/voltage, reliability, and stability violations where station and line equipment may be operating under conditions beyond their design limits. As part of this process, the Company generally applies several design concepts to resolve and mitigate issues identified in system analysis. Five of the more common design concepts include: reconfigure the system, upgrade existing equipment, add new equipment/capacity, construct or apply NWA solutions, and/or build a new substation (see Section 3.2.3 of the DSP for more information). The Company always considers the performance aspect of the solution alongside the total cost in choosing the most cost-effective solution that meets the need.

Typically, several solutions are developed for each capacity/reliability need and the process to select a final solution involves several groups and engineering disciplines which consider and compare a range of attributes for each alternative, including cost, reliability, constructability, and environmental impact. Once the comprehensive solution and/or solution alternatives are determined, the Company's project approval/construction process is used to initiate and implement a capital project. The process is designed to ensure that the technical approach is sound, and resources are budgeted and allocated to facilitate successful and timely execution of the projects.

Substation and transmission projects are large, complex, multi-disciplinary projects that require many years of planning and engineering, in addition to regulatory approval for siting and permitting. A typical timeline from planning to in-service for distribution bulk substation projects includes 20-42 months of planning and studies, 24-36 months of siting and permitting, and 54-78 months of construction. This reinforces the need for developing and implementing a 10-year capital planning process, since a delay on any of these projects could result in years of risk from equipment operated above thermal limits – risks that only increase in severity as load grows.

In identifying, designing, and implementing upgrade solutions to resolve violations, increase capacity, and improve reliability, the Company relies on its existing reliability criteria and planning standards to guide the selection of technically viable solutions. These standards (1) provide a consistent uniform approach for planning and designing an efficient, reliable, and safe electric power system; and (2) facilitate efficient study, interconnection, and operation of DER on the Company's system. Ultimately, the goal for a system experiencing demand growth is to provide reliable service in accordance with applicable safety codes and regulatory requirements and to provide orderly, economic expansion of the equipment and facilities to meet future system demand with acceptable system performance.

To meet its obligations, the Company takes a bottoms-up approach to integrated planning, with an annual cyclical planning cycle that starts with forecasting the net load on the system, i.e., the demand accounting for offsets due to DER production. As part of this process, the Company conducts a yearly analysis to build a 90/10 weather-normalized load forecast based on an econometric model for each of its operating companies, as described above. This forecast is conducted on a yearly basis to support the business-planning process.

As discussed in Section 3.2.2 of the DSP, to ensure the power system is adequately planned, three scenarios are typically considered when planning for large substation projects: a summer peak, a winter peak, and low load.

Based on the 90/10 weather normalized near-term load forecast, detailed analyses are performed to determine when and where violations in planning criteria and performance requirements occur. Following these analyses, the Company identifies the need to plan and construct new equipment, including non-wires alternatives, which expand the capacity of the system and increase reliability. This then increases the headroom for new loads as well providing additional hosting capacity for DERs to interconnect. Load and enabled DER capacity are then aggregated to the transmission level and constraints on the transmission system are identified, considering generation sources, retirements, and commitments.

Once violations and system deficiencies are identified, the Company develops comprehensive plans to position the electric transmission and distribution systems to meet the needs of customers from capacity, reliability, and resiliency perspectives. Projects authorized based on need identified in the 5- and 10-year forecast are developed, considering the potential for future growth to ensure that work done on the system today can handle projected future need and avoid early replacement of infrastructure.

Based on the system analysis results, the Company's engineers identify potential solutions to resolve thermal/capacity, power quality/voltage, reliability and stability violations where station and line equipment may be operating under conditions beyond their design limits. The solution development method is a complex and iterative process which addresses the system needs in conjunction with the capital budget and involves a wide array of disciplines and departments across the Company including siting, community engagement, engineering, system planning, substation design, permitting, environmental affairs, and more. PSNH considers options including upgrading existing equipment, constructing new equipment or capacity, reconfiguring the system, and constructing or applying NWAs. All studies to determine the best-fit solution are conducted prior to developing the preferred solution recommended for authorization. Once a preferred comprehensive solution and/or solution alternatives are determined via the system analysis process, the project approval/construction process is used to initiate and implement a project.

The Company follows a standardized process for initiating and then obtaining technical and financial approval for capital projects. This process ensures that the best solution is selected and that guiding principles are followed. It includes the review of project alternatives, scope, and cost estimates. Once a preferred solution with scope definition is chosen, it proceeds with the engineering analysis that includes more in-depth constructability review, below grade investigation, preferred routing selection, and equipment specification to obtain a more accurate project cost estimate. Initial siting and permitting preparation activities are also required at the preliminary engineering level.

Q. How has distribution planning evolved to address the current challenges on the distribution system?

A. The Company has integrated transmission planning, distribution planning, DER planning, reliability and resiliency planning, and advanced forecasting and modeling into a cohesive planning unit. This integrated planning organizational structure allows the Company to efficiently perform many complex distribution and transmission studies in a relatively short time.

In September 2020, the Company developed a comprehensive DSPG to provide a consistent, uniform approach to designing an efficient and reliable system that ensures the quality of service expected by our customers. Shortly thereafter, the Company developed an NWA Framework to provide a standardized and expedited process to screen an NWA solution’s technical and economic feasibility to meet a need at a specific location identified in accordance with the distribution planning criteria, and where deemed feasible, inform the application of non-wires technology or a combination of technologies through comparison of their relative benefits, performance and costs (see Section 5.1.4 of the DSP for more information about the NWA framework). Both the DSPG and the NWA Framework are essential components of our evolving approach to distribution planning and assessment of systems with high DER penetration.

Historically, the Company focused primarily on maximum (peak) load analysis as the driver for system design changes. Peak load analysis is focused on a specific time during a peak day when the system experiences the highest net demand, typically occurring during high load and low DER generation times. With increasing quantities of DER potentially leading to reverse flow during low load periods, this paradigm shifted, and minimum load models became just as important, depending on the amount of installed DER. However, because the interaction of load and DER is weather and time dependent, and due to increase in battery storage applications, our analysis timeframes have shifted even more from a peak and minimum load analysis to an 8760 load-flow model that accounts for all hours of the year.

Our analytic methods for assessing grid needs have also evolved with the nature and magnitude of demand on the system. As part of our integrated planning process the following analyses are conducted in accordance with the applicable standards and criteria identified in the DSPG:

- **Steady-state analysis** (in the minutes to hours timescale) to assess thermal overloads and voltage limit violations resulting from load and DER interconnections. The steady state analysis is conducted through time series power flow simulations in our distribution analysis package.
- **Dynamic/transient analysis (**in the milliseconds to seconds timescale) to verify acceptable model performance and to identify any violations of stability criteria or transient overvoltage criteria following system disturbances and switching actions. For this, the steady-state electric models are converted to dynamic models to allow for power systems EMT (electromagnetic transients) simulations.
- **Short-circuit analysis** to assess if circuit breaker fault interrupting capability or bus work short-circuit structural limitations or distribution equipment ratings are exceeded as a result of the interconnection.
- **Protection review** to assess if direct transfer trip (DTT), ground fault (zero sequence) overvoltage (3V0) protection or other special protection schemes are required based on the risk of islanding, back-feed at stations, and other operational requirements.

- **Reliability and operational flexibility assessment** to determine loss of load/DER reliability risk and degradation in transfer capability following a single-contingency event. This does not constitute a stand-alone analysis, but rather signifies that all previous analyses must account for the various permutations of system configuration, ensuring that the EPS is safe and reliable under all practical scenarios.

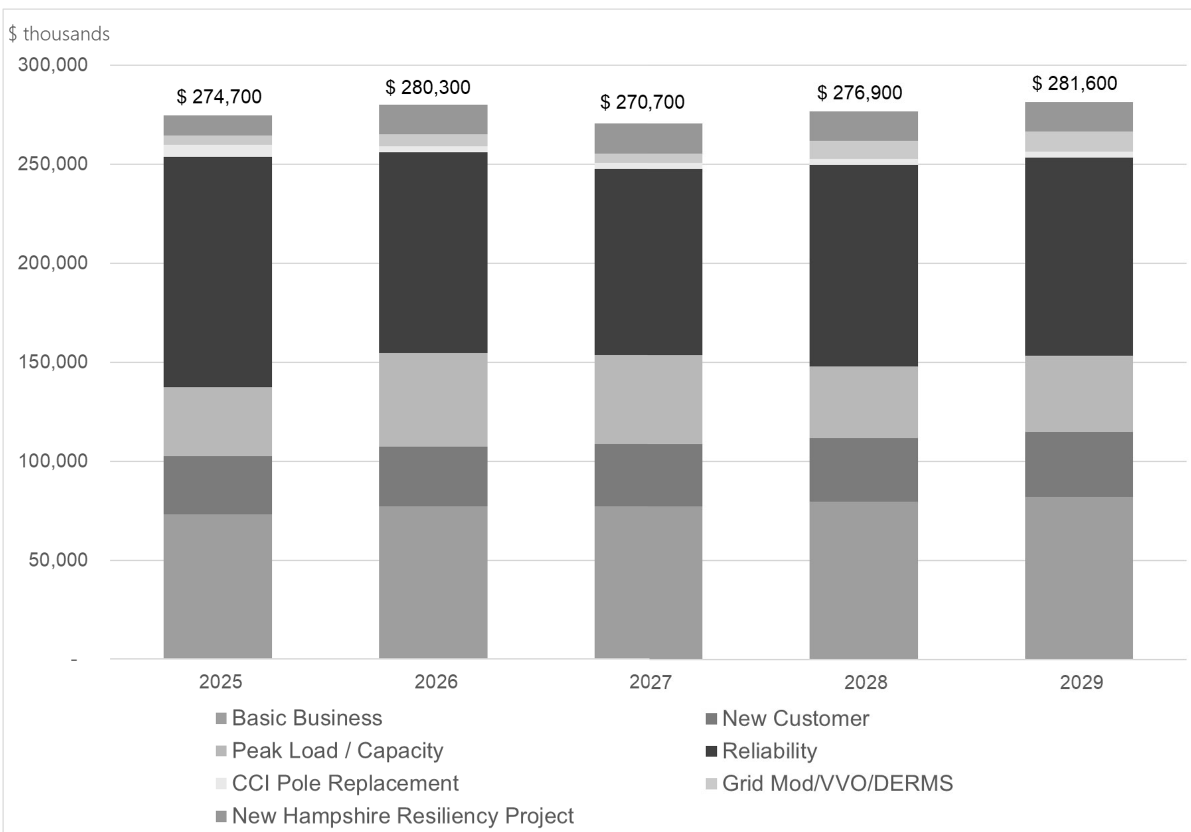
Over the same period, the Company examined potential tools with advanced planning methods. As discussed below and in Section 5.4.3 of the DSP, the Company would like to develop advance forecasting capabilities for system planning. The Company's Massachusetts affiliate received approval of funding to deploy an Advanced Forecasting system planning tool and has fully operationalized the tool in 2024 in Massachusetts. If the Commission approves the project in this proceeding, PSNH can develop an Advanced Forecasting tool leveraging its affiliates efforts, which will allow a detailed assessment of forecasts and support probabilistic modeling of scenarios for risk-based investment prioritization, as well as produce long-term electric demand assessments beyond the ten-year planning horizon.

VI. FIVE-YEAR INVESTMENT OVERVIEW

Q. Please provide an overview of the Company's planned solutions to address system needs.

A. Section 5 of the DSP describes the Company's solution set to address the capacity, reliability and system needs over the next five years. The 2025-2029 DSP includes multiple categories of investments that will improve the safety, reliability, resiliency, and clean energy enablement capabilities of the Company's electric distribution system, delivering value to customers on many fronts. The total investment is approximately $1.4 billion in capital over the DSP five-year term and is focused on reliability and resiliency and includes technologies to assist in optimizing the grid. Figure 1 below provides a summary of the Company's capital investment plan.

Figure 1: 2025-2029 Capital Investments ($ thousands)



The capital investment plan consists of two categories of investments: (1) core electric operation investments and (2) grid modernization and resiliency investments.

The first category of investments are the capital expenditures required to maintain safe and reliable service for customers. These investments include upgrades and new build of substations and distribution lines to accommodate load growth and maintain reliability, as well as improved telecommunications and upgrades to the Company's outage management system. The core electric operation investments are discussed in Sections 5.1 and 5.2 of the DSP.

The second category of investments included proposed investments that could be supported through the Company's proposed PBR mechanism with a K-bar, if the Commission authorizes the Company to do so. The proposed grid modernization and resiliency investments will harden the distribution system against more prevalent and stronger weather events, improve control room technology, optimize the system through voltage management, and provide planning tools for advanced forecasting and DER interconnection. The proposed grid modernization and resiliency investments are described in Section 5.3 and 5.4 of the DSP.

Q. Please summarize the Company's capacity need investments.

A. Based on the 5- and 10-year forecasts, the Company has identified substation upgrades and distribution circuit upgrades necessary to address capacity constraints. As discussed in Section 5.1.1 of the DSP, four substations (Cutts Street, Dover, Salmon

Falls, and South Milford) require upgrades or rebuilds to address specific capacity needs. The Cutts Street and Dover substation projects also will address reliability needs in addition to capacity. Specifically, the Cutts Street (Portsmouth) 12 kV capacity project will help address reliability needs at the Mill Pond Substation. The Dover substation rebuild will also address existing reliability needs at that substation.

Substation projects increase capacity or reliability in areas where projected capacity or reliability violations have been identified through the forecasting and demand assessment processes. New substation capacity that transforms power between the transmission and distribution systems is the foundation to make a meaningful and sustainable step-change in the amount of load and DER an area can accommodate. Over the next decade, the substation capacity and reliability projects in Section 5.1 and 5.2 of the DSP will add a total of 660 MW of transformer capacity, an increase of 17% over the existing 3.9 GW installed base.

In addition to substation projects, the Company has identified distribution circuit capacity constraints that need to be addressed in each region of its service territory. The Central region circuit capacity has had one to two percent growth with pockets of new commercial and residential load growth as migration from Massachusetts continues along the I-93 corridor. Current load growth in the area is outside of the downtown Manchester area, specifically with growth near the Manchester Airport and rural growth as well. Current and future capacity projects are planned in the Central region to support overloaded step transformers or overloaded distribution substation transformers (4.16 kV or 12.47 kV).

The Eastern region load continues to grow, with large commercial and residential growth in the area as migration from Massachusetts continues along the I-95 corridor. In the Pease area exponential commercial load growth continues as industrial load grows from the pharmaceutical industry. The Company needs to continue the expansion of its circuits in the Portsmouth downtown area, which is in a revitalization process, with new 12 kV systems. Other large towns in the Eastern region have historic 4.16 kV systems which are in the process of conversion, such as Dover where it is near completion of a conversion to 12 kV. Other towns in the region have growth where the overloaded steps require the conversion of the 4.16 kV system to 34.5 kV. Other portions of the Eastern region have overloaded step transformers which require a voltage conversion, as pockets of residential load and electric vehicle adoption continue to develop. This conversion also addresses aging infrastructure and when possible, the conversion facilitates additional circuit ties to be developed.

The load profiles of the Northern and Western regions have changed over the years. Vacation campsites have become vacation houses. In addition to new residential load, the regions are famous for their ski resorts which are large load centers. The Northern and Western region town areas are served by pockets of 4.16 kV systems which are fed from overhead step transformers. These transformers are at or near thermal capacity limits and the downtown system is near its end of useful life. These regions require kV conversions to provide additional load-serving capabilities.

The Southern region is similar to the Central region as it has experienced one to two percent growth with pockets of new commercial and residential load growth as migration from Massachusetts continues along the I-93 corridor. Current load growth pockets are from new residential complexes, retail facilities or warehouses along the Evergreen Parkway or I-93 Corridor. Current capacity projects are due to overloaded step transformers or overloaded distribution substation transformers (4.16 kV or 12.47 kV).

Q. Please summarize the Company's planned reliability investments.

A. The Company's reliability needs and solutions are described in Section 5.2 of the DSP. Within its service territory, PSNH supplies a range of rural and urban areas which often differ in electric supply characteristics and requirements. To maintain adequate levels of reserve capacity, power quality, and reliability that meet or exceed our customer's increased expectations, PSNH designs its bulk substations to sustain any single contingency event with no load loss. The single contingency events that are planned for include loss of a bulk power transformer, loss of a distribution bus section, and bus tie breaker failure. Based on criteria violations, the Company has identified 25 substation reliability projects, which are listed in the below table:

1 **Table 1: Substations with Reliability Needs**

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
Bedford Substation *Bedford*	Bedford, Litchfield, Londonderry, Manchester, Merrimack	Transformer Load & Bus Tie Breaker	Manchester Area Reliability Project
Eddy Substation *Manchester*	Manchester	Transformer Load & Bus Tie Breaker	Manchester Area Reliability Project
Garvins Substation *Bow*	Allenstown, Bow, Concord, Chichester, Hooksett, Epsom, Pembroke	Bus Section	Garvins Reliability Project
Huse Road Substation *Manchester*	Londonderry, Manchester	Transformer Load & Bus Section	Manchester Area Reliability Project
Pine Hill Substation *Hooksett*	Allenstown, Auburn, Candia, Chester, Deerfield, Hooksett, Manchester, Raymond	Transformer Load, Bus Section & Bus Tie Breaker	Manchester Area Reliability Project
Rimmon Substation *Goffstown*	Amherst, Bedford, Bow, Dunbarton, Goffstown, Hooksett, Manchester, Merrimack, Milford, Mont Vernon	Transformer Load, Bus Section & Bus Tie Breaker	Manchester Area Reliability Project
Brentwood Substation *Brentwood*	Brentwood, Chester, Epping, Fremont, Nottingham, Raymond	Transformer & Bus Section	Madbury Area Project
Dover Substation *Dover*	Dover, Rochester, Rollinsford, Somersworth	Transformer Load & Bus Section	Dover Substation Rebuild
Madbury Substation *Madbury*	Barnstead, Barrington, Brentwood, Deerfield, Dover, Durham, Epping, Epsom, Lee, Madbury, Newfields, Newmarket, Northwood, Nottingham, Pittsfield, Rochester, Strafford	Transformer Load & Bus Section	Madbury Area Project
Mill Pond Substation *Portsmouth*	Portsmouth	Transformer & Bus Section	Portsmouth 12 kV Capacity Project
Portsmouth Substation *Portsmouth*	Newington, Portsmouth	Bus Tie Breaker	Portsmouth 34.5 kV Project
Berlin Substation *Berlin*	Berlin, Cambridge, Dummer, Errol, Gorham, Green's Grant, Jefferson, Martin's Location, Milan, Millsfield, Pinkham's Grant, Randolph, Shelburne, Stark, Success, Wentworth's Location	Bus Section	Berlin Reliability Project

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
Laconia Substation *Laconia*	Belmont, Gilford, Laconia, Meredith, Sanbornton, Tilton	Transformer Load & Bus Section	Laconia Reliability Project
Oak Hill Substation *Concord*	Alton, Barnstead, Belmont, Boscawen, Canterbury, Chichester, Concord, Dunbarton, Gilmanton, Henniker, Hopkinton, Loudon, Pittsfield, Salisbury, Strafford, Warner, Weare, Webster	Bus Section & Bus Tie Breaker	Madbury Area Project
Pemigewasset Substation *New Hampton*	Alexandria, Bridgewater, Bristol, Danbury, Grafton, Hebron, Hill, Laconia, Meredith, New Hampton, Orange, Wilmont	Transformer & Bus Section	Ashland Area Reliability Project
White Lake Substation *Tamworth*	Albany, Conway, Effingham, Freedom, Madison, Ossipee, Sandwich, Tamworth, Tuftonboro, Wakefield, Waterville	Transformer, Transformer Load & Bus Section	White Lake Reliability Project
Bridge Street Substation *Nashua*	Merrimack, Nashua	Transformer Load & Bus Section	Nashua Area Reliability Project
Hudson Substation *Hudson*	Hudson, Litchfield, Londonderry, Nashua, Pelham	Bus Section	Hudson Reliability Project
Lawrence Road Substation *Hudson*	Hudson, Nashua, Pelham, Windham	Transformer & Bus Section	Lawrence Road Reliability Project
Long Hill Substation *Nashua*	Nashua	Transformer Load & Bus Section	Nashua Area Reliability Project
Scobie Pond Substation *Derry*	Derry, Londonderry, Windham	Bus Section & Bus Tie Breaker	Derry 12.47 kV Reliability Project
Chestnut Hill Substation *Hinsdale*	Chesterfield, Hinsdale, Richmond, Spofford, Stoddard, Swanzey, Westmoreland, Winchester	Transformer & Bus Section	Chestnut Hill Reliability Project
Jackman Substation *Hillsborough*	Antrim, Bennington, Bradford, Deering, Francestown, Greenfield, Hancock, Henniker, Hillsborough, Lyndeborough, New Boston, Peterborough, Nelson, Stoddard, Warner, Washington, Weare, Windsor	Transformer Load & Bus Section	Jackman Reliability Project
Monadnock Substation *Troy*	Fitzwilliam, Jaffrey, Marlborough, New Ipswich,	Transformer, Transformer Load,	Monadnock Substation Rebuild

Substation Name and Location	Communities Supplied	Criteria Violation(s)	Project Solution
	Richmond, Rindge, Troy, Winchester	Bus Section & Bus Tie Breaker	
North Road Substation *Sunapee*	Bradford, Claremont, Croydon, Enfield, Goshen, Grantham, Lempster, New London, Newbury, Newport, Springfield, Sunapee, Sutton, Unity, Warner, Wilmot	Bus Section	North Road Reliability Project

In addition to the specific substation reliability projects, the Company has general reliability programs discussed in Section 5.2.2.1 of the DSP. These programs address and replace obsolete substation equipment that has reached the end of its useful life, e.g., breakers (non-oil), reclosers, reactors, motor operated disconnects, fencing, ground grid, and annunciators. It also includes new substations, monitoring, and other equipment needed to improve substation or distribution system reliability. The need for equipment replacement under the general reliability programs is determined by inspections, testing, age of equipment, safety issues, operating issues, changes to standards, and spare parts availability. Currently, there are programs under way such as: battery replacements, relay replacements, RTU replacements, gas monitor replacements, gas monitor and health monitor installation, station service transformer replacements, battery monitoring installations, capacitor bank switch replacements, oil circuit breaker, oil filled recloser, and ancillary equipment replacement, substation animal protection installations and substation eliminations.

The Company's circuit reliability program discussed in Section 5.2.3 of the DSP utilizes a tool bench of data analytics tools to evaluate the most cost-effective approach for improving circuit reliability. Over the next several years, based on data and analysis, the improvement in available fault current, line segmentation, and the creation of circuit ties will ensure the reliability of Eversource's system both in blue and grey sky days.

Q. Please describe the Company's telecommunication replacement strategy.

A. The strategy is described in Section 5.2.5 of the DSP. Voice communication is a critical tool that the Company uses daily to maintain and operate the system. A reliable voice radio system is critical to PSNH's business because it is a lifeline for field crews that enables the communication between teams in various locations, provides fast and secure communications, operates independently of public cellular networks, and can enable continuous communication during emergencies or black starts when other existing communication methods may not be operable. These capabilities are key to enhanced situational awareness and ultimately employee safety.

There currently are 39 base radios used to create the voice radio network which connects approximately 825 mobile and portable radios. This equipment has been in service up to 30 years and is at end of life. The Company plans to update all the existing equipment to enable a digital mobile radio network. The digital mobile radio network will provide several benefits over the existing analog system, including improved audio quality, enhanced privacy and security, better coverage and range, integrated data services, scalability and flexibility, enhanced features and functionality, and interoperability. These benefits are described in detail in Section 5.2.5 of the DSP.

Q. Please describe the Company's outage management system upgrade.

A. The planned upgrade is described in Section 5.2.6 of the DSP. The Company's outage management system is planned to be upgraded to enable new capabilities and prepare for future use cases. The upgrade will include a common network model to improve situational awareness, enhanced web viewer for improved access and performance during major events, optimized process flows, improved mobile app for damage assessment, and enable future advanced metering infrastructure integration. The upgrade also ensures the software stays compliant, secure and compatible with the overall IT environment.

Q. Please explain why the Company is seeking authorization to implement the proposed grid modernization and resilience investments.

A. As discussed above and in the DSP, customer interaction and reliance on the electric grid is evolving. Customers are increasingly adopting DERs, electric vehicles, and relying on smart technologies and automated/computerized systems for their businesses. In addition, the region has experienced increasing number and severity of storms that threaten the electric grid. As the distribution system continues to evolve, so will the operational challenges and opportunities that face the system.

The proposed grid modernization and resilience investments can provide significant benefits to customers by hardening the distribution system, improving control room technology, optimizing the system through voltage management, and providing additional planning tools for advanced forecasting and DER interconnection. Specifically, with regard to resilience, proactive system hardening has benefits in storm response and restoration. The proposed grid modernization investments include Volt-VAR Optimization ("VVO"), Distributed Energy Resource Management system ("DERMS"), Advanced Forecasting for system planning, and Hosting Capacity and Interconnection Automation solutions. These enhancements, however, require significant revenue support and will be prioritized after the core electric operation investments discussed above and in Sections 5.1 and 5.2 of the DSP. The Company, therefore, requests authorization from the Commission to pursue these important modernization investments to deliver improved service and resiliency for customers. If approved, the Company does not propose to recover the costs of these investments through a reconciling factor. Instead, the Company will implement the investments and seek cost recovery as capital additions in the Company's next rate case proceeding, provided the Commission approves the proposed PBR mechanism with the three-year rolling average K-bar discussed in the Case Overview Testimony. The proposed PBR mechanism will provide the Company with the necessary revenue support to implement the proposed grid modernization and resiliency investments during the PBR term. As with all capital investments, the investments would remain subject to a prudence review and potential disallowance from rate base as part of the Company's next base-rate proceeding.

Q. Please summarize the Company's proposed resiliency investments.

A. The Company describes the resiliency investments in Section 5.3 of the DSP.

New England has already started seeing the impacts of climate change through the increased frequency and intensity of storm events resulting in elevated all-in SAIDI. New England was hit by three catastrophic hurricanes since 2010 – Isaias, Sandy and Irene. New England was also subjected to Winter Storm Alfred – also coined the 2011 Halloween Nor'easter – which arrived just two months after Irene. When looking at 40 years of storm data, these storms range between 1 in 30-year to 1 in 50-year events. But shortening the lookback period to more recent 15 years of storm data, suggests a dramatic compression in catastrophic storm probabilities in the range of 1 in 19-year to 1 in 23-year events. This substantial compression in storm probabilities when looking at more recent storm history demonstrates that these catastrophic storms are becoming significantly more likely in New England. Increasing transportation and building electrification, the proliferation of renewables and distributed energy resources as well as extensive reliance on the Internet for daily life, place the electric grid at the epicenter of various social and economic sectors. As a result, effective resilience planning to enable the grid to withstand outages and reduce the impacts of unavoidable events has become increasingly critical.

Under the resilience program, the Company will seek to enhance the resiliency of the system through (i) targeted undergrounding, (ii) reconductoring, and (iii) vegetation management.

The Company proposes to plan for resiliency using a data-driven approach. The resilience methodology scans the entire system for vulnerabilities and focuses specifically on high criticality outages, meaning outages with many customers impacted, long duration outages and multiple outages at the same zone (chronic problems). This comprehensive system scan enables a resilience program that targets high-yield projects first rather than across-the-board, generic, state-wide program implementation. This is based on advanced data analytics using highly granular outage data. The Company then uses data engineering to understand which attributes of outages and of the circuits are optimally responsive to projects. The resilience plan targets zones with high criticality; either those with multiple events (chronic problems/ repeat offenders) or those with high Customer Minutes of Interruption ("CMI") impacts per event. Eligible zones were paired with mitigations based on a combinatorial index of the number of events and the all-in SAIDI impact of the events. The projects were then ranked based on the SAIDI saved per dollar spent and the projects that are included in the Company's 10-year $150M resilience plan are the ones that fall under the optimal investment saturation point. Based on the analysis, the Company has identified 48 projects (14 undergrounding projects, 23 reconductoring projects and 11 vegetation work projects). The breakdown of the projects by region is discussed in Section 5.3.1.5 of the DSP.

Q. Please summarize the Company's proposed grid modernization investments.

A. The grid modernization investments are described in Section 5.4 of the DSP.

VVO is the process of optimally managing voltage levels and reactive power to achieve more efficient grid operation with the benefit of reducing system losses and energy consumption and improving the management of peak demand. VVO ensures that distribution voltages remain within prescribed tolerances and are not moving up and down rapidly as more DER is added to the system. In addition, managing these voltages to reduce energy consumption and optimizing demand will provide direct benefits to customers. The result is lower costs for customers, decreased carbon emissions, and increased DER hosting capacity.

The VVO program has three investment components: The first is to deploy and/or upgrade the substation transformer load tap changers, substation feeder metering, feeder voltage regulators, and feeder capacitor banks to enable two-way communication (also known as SCADA) such that the devices can be actively controlled by a centralized system in response to real-time voltage and reactive power fluctuations. The second component is the centralized intelligence program used to collect real-time data from the system, perform analyses and calculations, and send control signals to devices. The third component is the communications infrastructure needed to enable the two-way communication between the field devices and Eversource's centralized SCADA system. By deploying a VVO scheme on a distribution feeder, Eversource can improve the efficiency of this energy delivery, while at the same time dramatically increasing visibility into real-time grid conditions.

The Company is also continuing to improve its core control room technologies through software upgrades that deliver additional functionality and capabilities. The potential use of DER to provide grid services is driving the need for a DERMS to assist operators in managing DER assets. The DERMS is a software platform that can manage DER to deliver grid services and provide operators a tool to balance demand with supply on the distribution network. To achieve the optimal use of distribution system assets, the DERMS will organize connected assets and provide critical operational data for each asset to be a data input into the DMS. The DERMS will also act as the system from which the system operator will be able to issue commands to the DER to guarantee the safe and reliable operation of the distribution system in real time.

As discussed above, the Company's grid modernization investments also include leveraging Company affiliates' experiences to develop and deploy advanced forecasting capabilities in New Hampshire which will allow a detailed and automated assessment of bulk circuit level forecasts and support probabilistic modeling of scenarios for risk-based investment prioritization. While the Company has robust forecasting analysis, further support is needed to continue to advance the Company's forecasting and modeling capabilities. The growing complexity of the distribution system, characterized by two-way power flow and self-healing automation, will continue to drive the need for scenario planning that identifies system needs under multiple possible future configurations of load and generation growth. If the proposed advanced planning proposal is approved, the Company will leverage existing knowledge and capabilities to develop large scale power flow automation that can ingest the forecasts, conduct Monte Carlo simulations on various input parameters, and produce reports that inform distribution engineering, system planning, and regulators and policy makers on future investment decisions. The Company will develop, as part of its advanced forecasting capabilities, long-term demand assessment approaches which provide a 20–30-year outlook on state policy objectives and macroeconomic trends. These results will then be used as inputs into solution design of projects to ensure the Company develops only those solutions that serve a long-term purpose.

Finally, there is growing recognition in the electric power industry of the need to improve the efficiency and effectiveness of the process for assessing the impact of interconnecting DERs to reduce time and lower costs for customers. The volume of applications and the complexity of analysis are increasingly stressing the limits of existing engineering resources and their current processes. In recent years, new software tools have been introduced to effectively automate portions of the study process. These tools increase capability, reduce study time and free up high value resources to focus on more complex planning activities. The Company has invested in tools and solutions including Synergi Electric and Hosting Capacity Maps. Additional tools used in the interconnection process include Power Systems Computer Aided Design (PSCAD) and Power Clerk. However, to better service our customers, a more automated and streamlined approach needs to be considered.

In support of increasing the efficiency and effectiveness of the interconnection application study process, the Company is proposing to procure a software solution to enhance the Company's capabilities to quickly and accurately assess interconnection impacts in order to safely and reliably interconnect as much DER as possible. Specifically, PSNH will purchase a software solution to provide a dedicated and specifically tailored solution to DER planners while leveraging legacy investments in Synergi, PSCAD and Power Clerk by increasing integration and automation between the tools. In addition, the Company will merge hosting capacity information into the interconnection platform and provide users the ability to interact with the hosting capacity data to evaluate various options (location, curtailment, active management, storage, etc.) directly during the interconnection process.

The Company will also improve hosting capacity calculations to provide easy access to guidance on improvements to interconnection applicants. The proposed hosting capacity calculation enhancements will include time series to allow for the evaluation of specific operating modes and dispatch patterns.

The Company intends to develop a customer user flow allowing customers to actively engage with the interconnection portal and receive direct feedback on possible constraints of their application. While this will not replace an interconnection study, modifying the interconnection to better fit the available grid capacity significantly reduces the risk of associated interconnection cost. Furthermore, it will provide developers with more information on options to utilize storage assets or other measures to actively reduce their possible cost to interconnect.

Finally, by developing automation of all feasible study steps and an improved case management, PSNH expects a reduction of effort, and consequently time, required to study the interconnection request. The result will manifest itself with faster turnaround times for interconnecting customers, which directly results in reduced risk to projects.

These investments would build on the existing solutions. The Company has already undergone contracting with a vendor in Massachusetts to deploy these capabilities and intends to fully leverage this relationship for New Hampshire provided the Commission approves the proposed requests.

Q. Please explain the Company's plans for company-owned solar projects in New Hampshire.

A. As discussed in Section 5.5 of the DSP, PSNH is actively pursuing development of potential company-owned solar projects in New Hampshire on company-owned properties. The specific projects, their overall size and costs are currently under development. Under RSA 374-G, New Hampshire electric distribution companies are permitted to build, own and operate distributed generation under specific circumstances including when the benefits of such projects exceed the cost to ratepayers.

The Company is not seeking approval of its proposed solar projects at this time. The proposed projects were included in the DSP to provide the Commission with a comprehensive overview of the potential investments the Company may undertake over the next five-years based on approval of the Company's proposed PBR mechanism. As discussed in the Case Overview Testimony, the Company's proposed PBR mechanism is designed to reduce administrative burdens by eliminating the reconciliation of certain costs and providing revenue support for the Company. The Company's proposed three-year rolling average K-bar could provide the revenue support for the Company to pursue company-owned solar under RSA 374-G, without the need for a reconciling mechanism or step adjustments. Accordingly, if the Commission approves the K-bar proposal and the Company separately receives approval of a company-owned solar proposal, the Company will implement the solar projects subject to a prudence review and potential disallowance from rate base as part of the Company's next base-rate proceeding.

Q. Please explain the Company's co-optimized reliability enhancement proposal.

A. As discussed in Section 5.2.4 of the DSP, periodically, the Company must make significant infrastructure investments to accommodate a large new or expanded customer load. The customer contributes to the cost of the project through a contribution in aid of construction (CIAC) charge. However, these projects may also provide an opportunity for limited incremental investment to address broader capacity, reliability, and resiliency needs that benefit the broader customer base. For example, if a new customer load requires the construction of a new substation, the Company could also reconfigure the distribution lines to serve other customers from the new substation and alleviate constraints on existing substations, thereby improving service reliability. In this manner, for limited incremental cost, the Company can take advantage of these periodic opportunities to enhance safe and reliable service and potentially future-proof investments for the benefit of the broader customer base, rather than just the customer triggering the infrastructure upgrade.

The Company requests Commission authorization to pursue these grid reliability enhancements through co-optimization of customer-driven investments under the K-bar proposal described in the Case Overview Testimony. If the Commission approves the proposal, when the opportunity arises, the Company will seek to co-optimize customer-driven investments to provide customers with cost-efficient reliability benefits. The Company proposes that these projects will be incremental to any capital investments included in the K-bar calculation, and not subject to the K-bar cap. Since these investment opportunities are not within the control of the Company and costs may be significant, the Company needs flexibility to pursue co-optimization opportunities outside of the planned annual capital budget. Similar to the proposed solar investments, the Company proposes to implement the co-optimization reliability enhancement projects subject to a prudence review and potential disallowance from rate base as part of the Company's next base-rate proceeding.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes. On behalf of PSNH, we appreciate the Commission's consideration of the Company's proposals in this case.