STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 23-039

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Distribution Service Rate Case
Operations

DIRECT TESTIMONY

OF

ANTHONY STRABONE

April 28, 2023

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I. INTRODUCTION

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

A. My name is Anthony Strabone, my business address is 9 Lowell Road, Salem, New Hampshire, and I am employed as the Senior Director of Electric Operations by Liberty Utilities Service Corp. ("LUSC").

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony before the New Hampshire Public Utilities Commission (the "Commission") on behalf of Liberty Utilities (Granite State Electric Corp. d/b/a Liberty ("Liberty" or the "Company").

Q. Please describe your educational and professional background.

A. I graduated from Merrimack College in 2004 with a Bachelor of Science degree in Electrical Engineering. I received a Master of Business Administration degree from Southern New Hampshire University in 2006. I received a Project Management Professional (PMP) Certification in 2017 from the Project Management Institute. In 2019, I received my license as a Professional Engineer in the State of New Hampshire. I joined LUSC in November 2014. Prior to my employment at LUSC, I was employed by Public Service Company of New Hampshire ("PSNH") as a Substation Supervisor in Substation Maintenance from 2010 to 2014. Prior to my position in Substation Maintenance, I was a Substation Engineer in Substation Engineering from 2008 to 2010 and an Engineer in the System and Planning Strategy department from 2004 to 2008.

Q. Please describe your duties at Liberty.

A. I am the Senior Director of Electric Operations for LUSC. In that capacity, I am responsible for the safe and reliable operation, design, and maintenance of the electric system for Liberty in New Hampshire.

Q. Have you previously testified in regulatory proceedings before this Commission?

A. Yes, on numerous occasions, and most recently in the Company's latest LCIRP, Docket No. DE 21-004.

Q. Are you sponsoring any exhibits or schedules?

A. Yes. I am sponsoring two attachments and a number of figures and tables, which are listed above.

II. <u>SUMMARY OF LIBERTY'S SYSTEM</u>

Q. Please provide an overview of the Liberty distribution system.

A. As the Company looks toward the future of the electrical grid, it must consider how customer needs and expectations have changed over the past decade, and where those expectations may go in the short and long term. Overall usage trends show an increase each year given the nature of more electronics in the home, installation of heat pumps, and penetration of electric vehicles on the road. With technology propelling that usage increase, grid reliability has become more important than ever.

Over the past eleven years, Liberty has upgraded its distribution system through capital investments pertaining to reliability, safety, and technological advances to ensure its customers receive the excellent service at a cost that is just and reasonable. Most of those investments have included upgrading and adding substations, replacing radial feeder schemes with loop schemes, and installing more technologically advanced devices to allow for shorter-duration interruptions.

While these investments have provided better reliability, there is still much work to be done. The Salem area has seen the installation of a modern substation, but there remain substations on the Company's system that are old and in need of upgrades to maintain safe and reliable service to customers in the area.

In the Charlestown area, the Company built the Michael Ave substation in 2016 to replace the antiquated Charlestown substation, but most of the feeders from this new substation continue to be radial scheme and do not have the capabilities to switch load during outages to reduce the duration for which customers are without power. While this area of the system has SAIDI and SAIFI numbers greater (worse) than the Company average, the rebuilding of this area also ranks low on the risk index, the matrix used to determine the prioritization of a project based on a number of factors, due to the modest number of customers being served in the area. The focus in the coming years is to rebuild these feeders with loop schemes and adding SCADA capabilities to allow for switching as needed. Another problematic issue is that the Vilas Bridge substation serving the Walpole area is antiquated but the possibility of upgrading or replacing the substation is a challenging process because it is owned by National Grid in Bellows Falls, VT. Accordingly, the justification for the upgrade or replacement of the Vilas Bridge substation must be in accordance with both National Grid's and Liberty's asset replacement strategies, capital investments, and approval processes.

The Lebanon area has seen its share of system upgrades allowing for greater reliability in the area, most notably the expansion of Mt. Support Substation, but also has problem areas as the feeders move from the substations out towards the less suburban and more rural towns of Canaan, Enfield, and Plainfield.

III. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. There are two purposes of my testimony, (1) to provide a prior and future capital spending breakdown, and (2) to propose modifications to storm restoration cost recovery. I first provide the capital spending breakdown for calendar years 2020 through 2022 in support of the Company's request for a permanent rate increase. Since the Company is also proposing a multi-year rate plan, I will provide details of some of the significant planned capital spending in future years. The multi-year rate plan is needed to address the issue of earnings attrition that Liberty experiences between rate cases, even when it files rate cases on a relatively frequent basis. With more prompt cost recovery for capital investments, the timing of rate cases for Liberty will be less frequent since the primary factor driving the need for rate cases is the recovery of capital investment, particularly non-growth-related capital investments. This issue is further discussed in the testimony of Company witness Erica L. Menard.

My testimony will then provide an overview of the current storm cost recovery mechanism and propose modifications to allow for more robust storm planning and response.

IV. LIBERTY'S ELECTRIC DISTRIBUTION SYSTEM FACILITIES

Q. Please describe the Company's electric delivery system including how it is designed, constructed, and operated.

A. Liberty distributes electricity to approximately 46,000 residential, commercial, and industrial customers in 23 communities in Southern and Western New Hampshire. To serve its customers, the Company utilizes 14 distribution substations supplying approximately 52 distribution and sub-transmission feeders. Approximately 80 percent of the 2,053 miles of distribution and sub-transmission circuits on the Company's system are overhead facilities operating at voltage levels ranging from 2.4 kV to 23 kV. Approximately 99 percent of the distribution and sub-transmission system operates in the 15 kV class range or below (2.4 kV to 13.8 kV). The Company recently constructed two supply lines, each 2 miles in length, operating at 115 kV.

A. Distribution Substations

The distribution substations within Liberty's territory are a mixture of stations with one or more transformers. In the Southern Area, Olde Trolley and Spicket River substations have 23/13.8 kV, 5-10 MVA-rated transformers with individual voltage regulators applied to the feeders and are wholly owned by Liberty. In the Western area, Hanover, Craft Hill, Lebanon, and Enfield substations involve 13.8 kV Supply and 13.2 kV regulation. Except for Rockingham Substation, which is solely owned by the Company, the distribution substations supplied by the 115 kV circuits are jointly owned by Liberty and National Grid. Currently, Liberty and National Grid maintain five distribution substations containing nine power transformers in the Liberty service territory.

B. Sub-Transmission System

Liberty's sub-transmission system is designed to provide adequate capacity between load centers at a reasonable cost and with minimal impact on the environment. It provides supply to distribution substations and consists of those parts of the system that are neither bulk transmission nor distribution. The voltages for the sub-transmission system include 23 kV and 13.8 kV. The sub-transmission system is designed in an open loop system and generally provides a redundant supply for distribution substations. Currently, Liberty maintains ten sub-transmission lines.

C. Distribution Feeders

The majority of the Company's distribution feeders from each substation are in a "looped" configuration with provisions for the transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits. These feeders may be interconnected to an adjacent circuit to facilitate manual, and in some instances, automatic, reconfiguration to isolate faulted sections on the line and to "switch before fixing" to quickly restore customers. Each feeder is usually divided into several switchable elements or sectors. During emergencies, segments can be reconfigured to isolate damaged sections and re-route power to customers who would otherwise have to remain without service until repairs were made. Over the next several years, Liberty will focus on a systematic approach to increase the use of distribution automation to expedite these reconfigurations and increase the ability to remotely operate the system, which improves reliability and supports the Company's commitment to providing safe and reliable electricity

Q. Please describe how the Company's electric delivery system has changed and any improvements made since the Company's last base rate case.

A. Since the Company's last rate case (Docket No. DE 19-064), it has invested in several areas of the system. In Salem, Liberty has built out what was Rockingham Park – a former dog racetrack – now revitalized into an urban development known as Tuscan Village. The Company also built the Rockingham substation in Salem, including 13 kV distribution circuits and two 115 kV lines to serve the area load, address asset conditions, and modernize its aging electrical infrastructure.

The Company has also continued investing in damaged and failing equipment, replacing direct buried underground cable, and completing public requirement projects in response to State of New Hampshire and municipalities' requests to relocate the Company's poles and associated equipment on the poles to accommodate various state and municipal projects such as road widening. Finally, the Company has invested in projects such as the New Hampshire Battery Pilot where customers have Tesla Powerwalls installed in their homes to reduce peak usage, DTN Weather Storm Impact Analytics to help the Company better forecast its restoration needs prior to a storm occurring, and a Meter Test Board which allows the Meter Department to be more efficient in testing meters from the manufacturer and returned from the field.

Q. Please describe how the Company's distribution system is maintained.

A. Liberty maintains its distribution through its Operations and Engineering workforce and its Dispatch and Electric Control departments. The Operations group is made up of its Line, Substation, Meter, and Vegetation departments. These departments work in the field to operate and maintain the physical assets of the electric system. The Engineering department is made up of Electrical Engineering and Project Management. These departments determine the current and future needs of the system, design work to be completed by the Operations group, and oversee construction related to the Company's capital plan to ensure projects are completed on-time, within scope, and on budget. Dispatch and Electric Control have full visibility of the system 24/7 and provide guidance and direction to Operations and Engineering personnel when there are known issues on the system.

The Company maintains assets on the electric system in accordance with its maintenance and inspection programs. These programs are based on industry-accepted practices which identify the types of inspections and tests, and the frequency interval they must be performed to ensure equipment is adequately maintained, ready for service, and functions properly when required to do so.

Q. How does the Company discover and address system outages?

A. The Company uses Supervisory Control and Data Acquisition ("SCADA") where it has been installed to discover system outages. In areas where SCADA is not installed, Liberty relies on customers to inform the Company that an outage has occurred. However, with the implementation of AMI, the AMI meter will notify the Company when a system outage occurs, reducing the Company's dependency on customer calls reporting a system outage. The Company's AMI implementation is further described in the testimony of Company witnesses Balashov and me.

Q. How does the Company prepare for potential system outages related to severe weather?

A. As previously noted, Liberty invested in Storm Impact Analytics to help provide further guidance on the severity of impending storms. The Company also institutes the Incident Command Structure ("ICS") when a level 3 or greater impact on the Company is anticipated (2100 – 4200 customers out). Instituting ICS in advance of a storm provides comprehensive preparation to potentially reduce restoration time. Preparation includes securing contractors, positioning internal employees where they are most needed, and communicating to customers that a storm is coming to ensure the Company has made the necessary preparations to restore power as efficiently and safely as possible.

V. MEASURING THE RELIABILITY OF LIBERTY'S ELECTRIC SYSTEM

Q. Explain the reliability indices used to measure the effectiveness of the Company's maintenance programs and system reliability.

A. The Company utilizes reliability metrics based on the Puc 307 Records and Reports sections of the New Hampshire Code Of Administrative Rules, which provides direction on how to report on reliability indices including removal of major event days under the Major Event Threshold ("TMED") formula as defined by the Institute of Electrical and Electronic Engineers ("IEEE"). The metrics presented also exclude transmission supply outages, planned or notified outages, and all other applicable exclusions.[1] The metrics include customers interrupted ("CI"), customer minutes interrupted ("CMI"), system average interruption frequency index ("SAIFI"), system average interruption duration index ("SAIDI"), customer average interruption duration index ("CAIDI"), and customers interrupted per interruption index ("CIII").

Q. Does the Company regularly report its system performance to the Commission?

A. Yes, pursuant to Puc 307.09(b) and Puc 308.18, the Company files E-38 Quarterly Reporting of Electric Utility Reliability Measures.

Q. How has the Company's system performed as measured by these reliability indices?

A. The below graph depicts how the Company's reliability has been trending since 2014. Overall, the Company's reliability targets have been trending down, which correlates to an improvement in reliability with respect to SAIDI and SAIFI. The Company's

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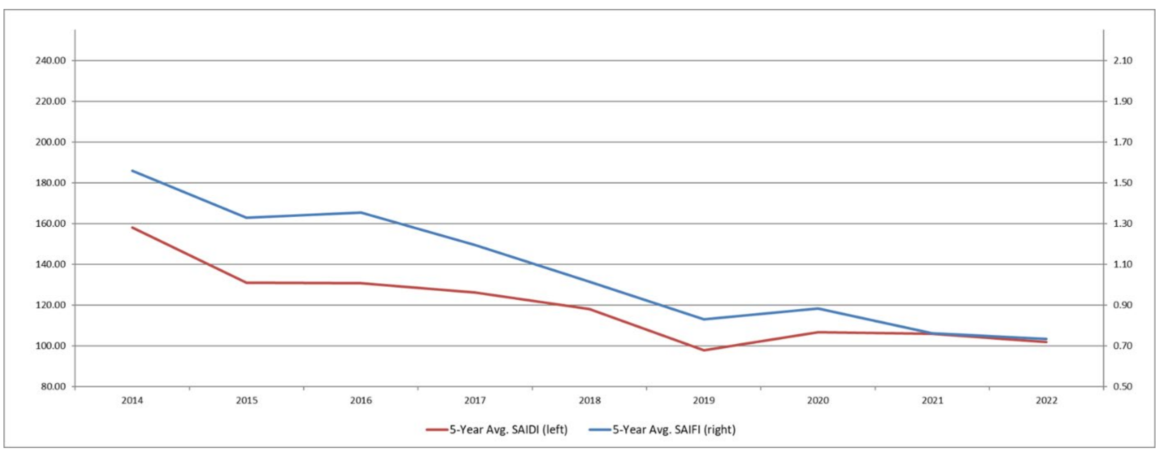
[1] Events that are excluded are those involving loss of supply from another utility, customer-owned facilities, fire or police emergencies, load shedding, planned maintenance, events whose duration was 5 minutes or less

reliability targets are based on a rolling 5-year average, meaning the targets for 2023 are based on reliability performance for the previous 5 years (2018–2022). For 2023, the Company has a SAIDI target of 98.78 minutes and a SAIFI target of 0.736. Although the Company's reliability targets are approaching the first quartile, there are areas within the electrical system that are experiencing poor reliability. These areas are identified as 'Pockets of Poor Performance' or a 'Worst Performing Feeders.' One such area is the Company's Bellow Falls Area where two of the area circuits, 12L1 and 12L2, have pockets of poor reliability. The performance of these circuits is further explained in the Bellows Falls Reliability Report 2022 filed as Exhibit 4 in Docket No. DE 21-004 on May 2, 2022.

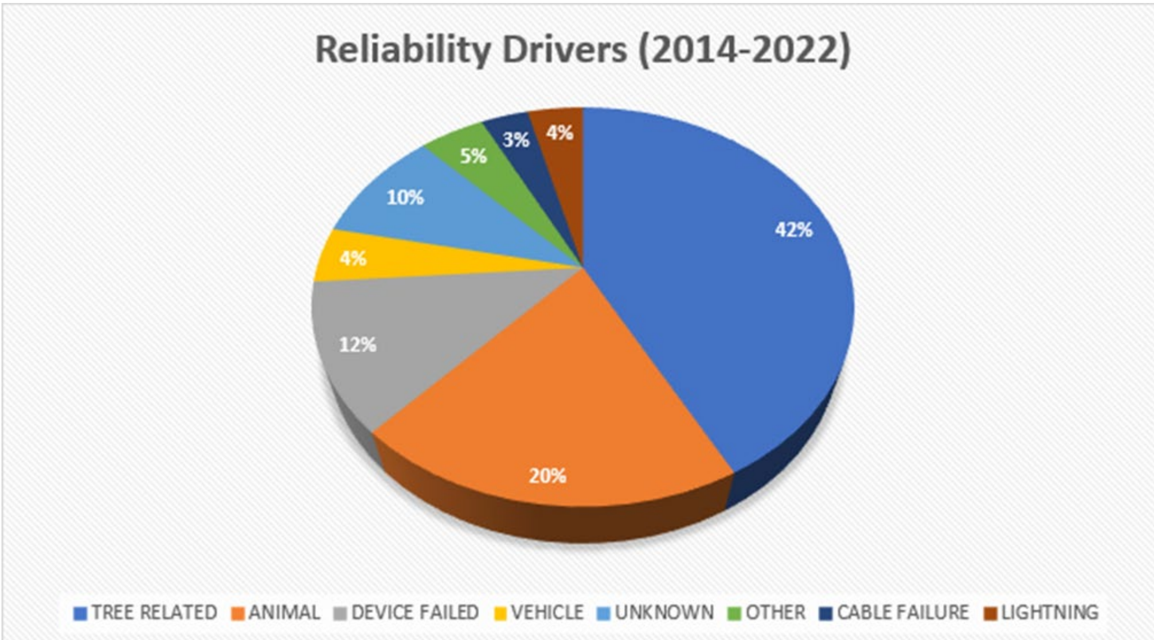
Figure 1. Five-Year Average SAIDI & SAIFI



Q. What are the main drivers impacting the Company's reliability?

A. The following chart shows the main drivers impacting the Company's reliability with vegetation management being the most significant. Animal contacts and failure of devices are the next two. Collectively, these three drivers comprise 74% of the causes resulting in customer outages.

Figure 2. Reliability Drivers 2014–2022



VI. MAJOR CHALLENGES FACING LIBERTY'S ELECTRIC SYSTEM

Q. What are the major challenges facing Liberty's distribution system?

A. The Company is facing challenges with respect to investing in the infrastructure of the distribution system to address aging equipment, growth, supply chain issues, and customer expectations to provide safe, reliable electric service with reasonable rates.

A. Aging Infrastructure

While the Company has invested over the years to upgrade its system and replace antiquated equipment, many areas of the system still need to be addressed because of aging infrastructure. The Company's electric system was built decades ago with equipment and technology which was considered ‘modern’ at the time of construction. Although the Company continues to maintain its electric equipment, the older a piece of equipment becomes, the inherent risk of failure continues to increase, which could have a negative impact on reliability. When an older piece of equipment fails, finding replacement parts may not be feasible due to the manufacturer and aftermarket industry suppliers no longer supplying them, which in turn results in a replacement project. One-for-one equipment replacement may not be feasible due to newer industry standards resulting in the same piece of equipment being physically larger today than it was decades ago.

Further, the technology of decades ago, which is still in operation today, is not capable of supporting the grid modernization initiatives of today and into the future. As distributed energy resources (“DER”) continue to grow, combined with Electric Vehicle (“EV”) adoption and increased implementation of distribution automation solutions, the technology used on the electric system must be able to control a dynamic grid focused on optimizing power grid efficiency and reliability.

A recent investment by the Company to address aging infrastructure was the construction of Rockingham Substation and Supply Lines. The Company performed the Salem Area Study to assess the electrical grid in the Salem area with the purpose of replacing two antiquated substations and equipment with a single substation constructed to the latest industry design standards and technology capable of supporting the future installation of grid modernization initiatives such as distribution automation. My testimony further describes the upgrades from this study below.

B. Supply Chain Issues

The consequences of the pandemic's supply chain issues have impacted the Company in ways it would not have imagined pre-pandemic. Disruptions including logistics bottlenecks, labor shortages, and scarcity of raw materials and components have resulted in rising costs and long lead times for essential equipment like wires, poles, and transformers. These problems have created longer lead times needed to design and complete a project and the potential of delayed projects beyond the customer's expectations is becoming more and more frequent. These supply chain issues not only impact customers, but also have an impact on the Company when it comes to capital investment in foundational projects such as Bare Conductor Replacement, replacement of underground wire, or damaged/failed equipment. The Company continues to work with its suppliers and other utilities to source material to mitigate these disruptors, but as supply chain issues continue, alleviation from long lead times and increased costs are becoming more difficult.

C. Localized Growth

Over the past five years, Liberty has seen significant growth in its Salem area primarily due to the Tuscan Village development. While customers are required to go through the tariff-mandated process of determining if a Contribution in Aid of Construction

("CIAC") is applicable, the CIAC does not cover the entire cost and there is still a portion borne by the Company (and ultimately its customers) to build the service.

D. Customer Expectations on Reliability

As described in my Executive Summary, customer expectations on reliability are higher than ever with the advent of lower-cost electric vehicles, installation of heat pumps, and simply more electronics being charged in the home. With those expectations comes the need for careful planning and capital investment practices that the Company undertakes annually to ensure its system continues to provide safe and reliable service, all while keeping rates reasonable.

E. Storm Restoration

The impacts on the distribution system during storms may be significant. Many times, there are numerous broken poles, spans of wire down, and damaged transformers which all require substantial repairs and replacement. The cost of storms has also seen an uptick given the increase in labor and materials. Liberty has seen over the last few years storms wreaking more havoc than it has in the past. In December 2022, the Company saw its fourth and fifth largest storms occur the week leading up to Christmas and only a few days apart. Further information about Liberty's restoration practices is provided in Section VIII.

Q. Explain how the addition of renewables impacts the reliability and resiliency of the distribution system.

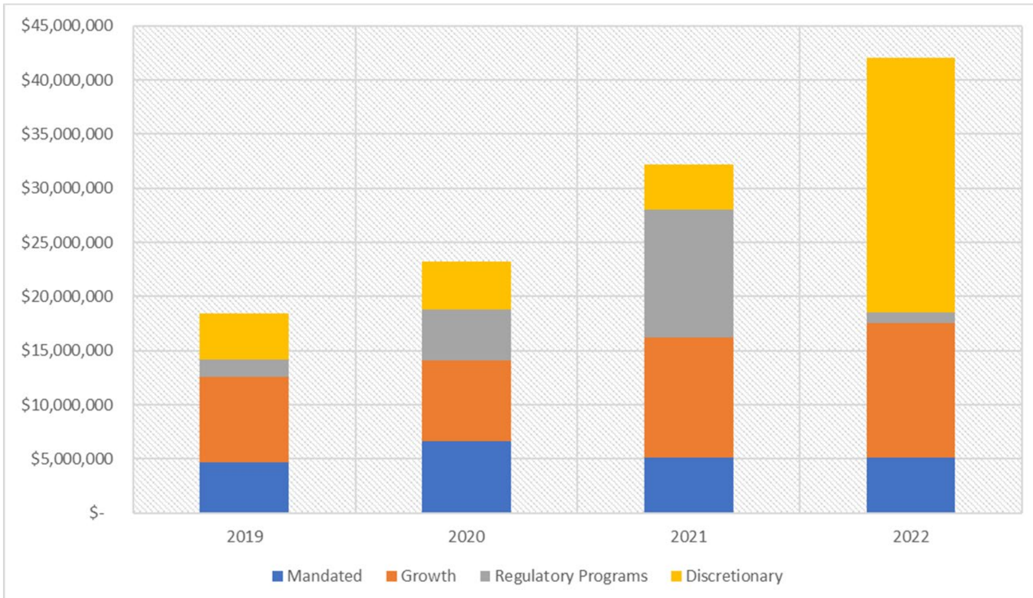
A. Renewables being added to the system have pros and cons. Some of the pros of adding renewables to the system are that those customers may have power backup in the event of an outage and they are potentially taking less power from the grid during high-use periods if their renewable generation is making power at that time. This can alleviate the stress on Liberty's equipment. The primary con of renewable generation is its intermittency. Intermittent generation can create voltage issues for customers in the vicinity. For example, a 1 MW solar array producing at full power on a sunny day may quickly go offline when sizable clouds pass over the array, blocking the sun. When this happens, the system voltage will drop requiring the electric grid to quickly respond and rectify the low system voltage. Once the clouds pass, the solar array may come back online, resulting in high system voltage and once again, requiring the electric grid to quickly respond and rectify the situation. This scenario can happen numerous times throughout the day causing excessive wear and tear on system equipment, such as line regulators, which can lead to increased maintenance and premature equipment failure.

VII. LIBERTY'S INVESTMENT IN DISTRIBUTION FACILITIES

Q. Please describe Liberty's investment as it relates to service reliability and quality improvements.

A. The Company classifies its Capital Investments into the five categories listed below and the following chart depicts the Company's Capital investments over the past four years:

Figure 3. Liberty Capital Investments 2019–2022



1) Safety - those used to reduce workplace hazards, accidents, and exposure to harmful situations.
2) Mandated - used to meet statutory or regulatory compliance.
3) Growth - those used to expand the physical plant. For example, projects such as extending distribution mains or services, installation of new feeders, and expansion of substations.
4) Regulatory Supported - those used to implement projects where special regulatory mechanisms have been established to accelerate the financial returns of specific initiatives.
5) Discretionary – any capital project that does not fall into the previous categories.

Q. Is all the capital investment described above included in rate base in this case used and useful in providing service to the Company's customers?

A. Yes, it is.

Q. Please describe the major investments undertaken since 2019.

A. The Company undertook the following system capacity and reinforcement projects in the years 2019 through 2023. These projects were necessary to allow for the phased retirement of substation assets that have exceeded their useful operating and economic lives, as well as to provide additional capacity in specific areas that have experienced residential and commercial load growth over time. They also resolved existing and forecasted violations of the Company's planning criteria.

A. <u>Golden Rock Substation Upgrade</u>

The Salem area relies on the 23kV supply system emanating from the Golden Rock substation and the National Grid sub-transmission system in Massachusetts. The existing 23/13kV substations do not have the necessary capacity to supply the upcoming planned customer expansions in the area. Two of the substations, Salem Depot and Barron Avenue, were built in the mid-1950s and early 1960s, respectively, and have reached the end of their useful economic lives.

Under this project, Liberty installed two 13kV feeder positions including overhead and underground street construction in 2019 and a third 13 kV feeder in 2022. As part of this project, National Grid provided a second 115kV transmission line and a new 115/13kV transformer. This provided distribution capacity to back up the Spicket River substation, which is currently supplied via a single 23kV supply line from National Grid in Massachusetts.

The Golden Rock project helped redistribute the Salem area feeder loading to comply with Liberty's planning criteria allowing for improved reliability and storm/contingency performance and will mitigate issues with asset condition at the Baron Avenue substation by allowing for its retirement in 2025. Since the work was completed, approximately 13.42 MW of load has been transferred from the Baron Avenue substation to the Golden Rock substation.

B. Rockingham Substation

In the fall of 2020, Liberty began construction of the Rockingham substation, which was identified as the preferred solution in the Salem Area Study to address concerns with asset conditions, obsolete equipment, aging infrastructure, system resiliency, modernization of the electric grid, and area load growth. Rockingham Substation, in connection with the upgrade to Golden Rock substation, provides the ability to retire both Baron Avenue and Salem Depot Substations, both of which have obsolete equipment or asset conditions that lack the necessary capacity to supply customer expansions in the area. Since its 2021 in-service date, 17.16 MW of load have been transferred from the Salem Depot substation to the Rockingham substation.

The project included installing a new metal-clad switchgear with a control house, two 55 MVA transformers, and ten 13 kV distribution feeder positions. In 2021, Rockingham Substation, along with five distribution feeders was placed in-service. Building the substation also provides the capability to aid in the supply of Spicket River substation load during an N-1 contingency. Spicket River during a loss of the supply line, especially when loading is high, requires multiple circuits fed out of Rockingham, Golden Rock, Old Trolley, and in some instances National Grid substations out of Haverhill, MA, to fully restore.

C. Rockingham Supply Lines

To provide the necessary firm capacity to the Rockingham substation, the Company worked with National Grid to design a solution to feed it. The recommended solution, as identified in the Salem Area Study, was to construct two 115 kV supply lines, with 23 kV under build, in the existing 23 kV right of way. Both lines are two miles in length, interconnecting to National Grid's 115 kV electrical system at Golden Rock Substation. The first 115 kV line, referred to as the 115 kV East Circuit, was energized and placed in-service in 2021, and the second 115 kV line, referred to as the 115 kV West Circuit, will be in-service in 2023. The most cost-effective solution was for Liberty to build the supply lines because National Grid did not need the power and, had National Grid built the lines, the Company would have paid the full cost. Along with paying for the full cost, the Company would not have been able to connect its 23 kV overhead lines to the structures because those structures would have been National Grid-owned assets. The Company would have been required to install a manhole and duct system to provide power from the 23 kV lines to its existing Olde Trolley, Barron Avenue, and Salem Depot substations while the Rockingham substation was being built. The Company avoided these costs by building the supply lines itself.

Q. Does the Company have any significant capital projects planned for the near future?

A. Yes. The Company has presented a multi-year capital spending budget in Attachment AS-2, but there are several large projects spanning multiple rate years outside of the annual blanket projects that Liberty is planning to undertake. These include installing the Vilas Bridge 12L1-12L2 feeder tie at approximately $6.1M, continuation of the bare conductor replacement program at approximately $10.5M, underground cable replacement at approximately $6.7M, and installation of Advanced Metering Infrastructure ("AMI") at approximately $40M.

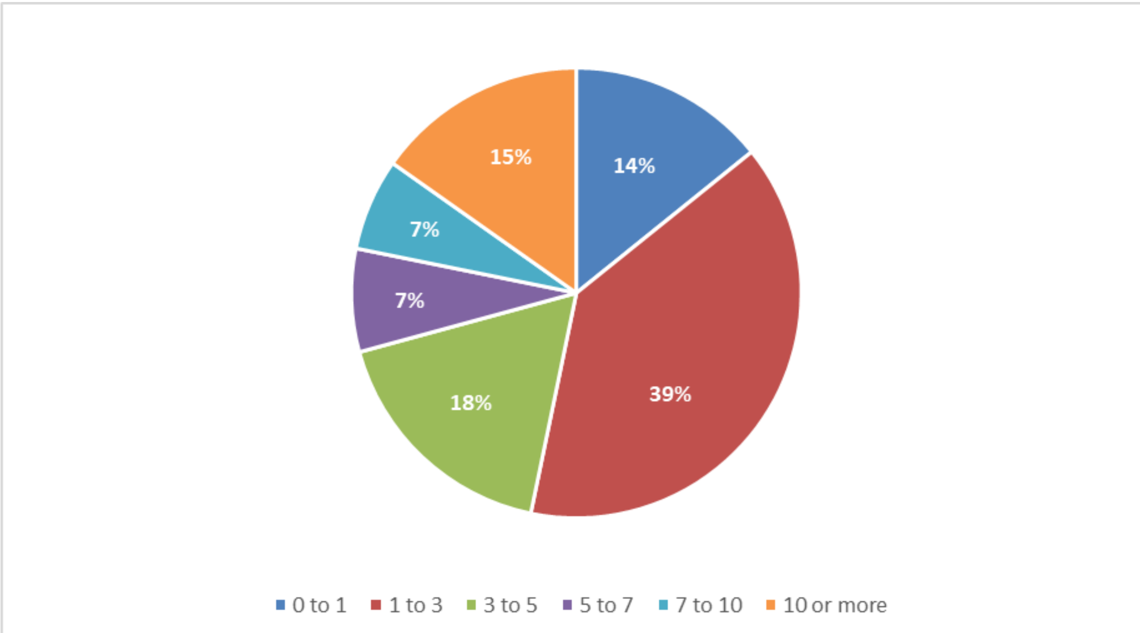
D. <u>Vilas Bridge 12L1-12L2 Feeder Tie</u>

The 12L1 and 12L2 circuits tend to have lengthy outages. As depicted in the figure below, approximately 30 percent of the outages which occur on 12L1 and 12L2 are greater than four hours in duration. As identified in the Company's Report on Wires and Non-Wire Solutions to Address Reliability in the Bellows Falls Area,[2] the preferred solution to help address the lengthy outages in this area is to construct a 9-mile, 3-phase line extension from the 12L1 circuit at Route 12A, Alstead to the 12L2 circuit at Watkins Hill Road in Walpole. The benefit of this option is that it would create a more useful circuit tie in the more rural areas of both the 12L1 and 12L2 circuits and allow the Company to utilize distributed automation for multiple zones. This tie not only is in the

[2] *See,* Attachment AS-1.

optimum location for both circuits but puts 3-phase primary throughout a much larger area which would give more opportunities for future DER interconnection.

Figure 4. 12L1 and 12L2 Outage Durations in Hours from 2017–2021



Bare Conductor Replacement Program

The Bare Conductor Replacement Program is a targeted capital program that provides for the reconductoring of bare mainline primary conductor with tree wire in spacer cable configuration along with the installation of reclosers and trip savers. These installations have the explicit purpose of improving system reliability.

Underground Cable Replacement

Underground residential developments ("URD") and underground commercial developments ("UCD") have historically been served by 15kV class #2 three- or single-phase solid dielectric cables. Through the years a number of different insulations have been employed across the Company including XLPE and EPR cables. Likewise, these cables have been installed directly and either buried or in conduit systems.

Direct buried solid dielectric cables installed from the late 1960s through the late 1980s have shown the most susceptibility to failure. The causes of failure have ranged from improper backfill material during initial installation, damage from the third-party excavations, and an incomplete understanding of XLPE failure mechanisms by the industry such as water, trees, electrical stress, concentric neutral (“CN”) corrosion, etc. These cable types have also shown a susceptibility to neutral corrosion and tend to be XLPE or PE insulated and are more than twenty years of age. This project will look to replace underground cable to avoid future failures.

<u>AMI</u>

An AMI network is seen as a key foundational element of grid modernization. While AMI will provide demonstrable benefits by itself, it also provides the needed infrastructure for programs such as conservation voltage, fault detection, distribution automation, and load forecasting. This project is further described in the Balashov/Strabone testimony.

Q. How does the Company determine the order in which it undertakes capital investments?

A. As part of the Company’s capital planning process, a risk score is assigned to determine the prioritization of a project. Identifying a risk score for each project provides the prioritization method for project selection when the Company is determining its Capital investment requirements but also the method to remove projects from the Capital plan, when necessary, and have the visibility of the potential impacts (i.e., reliability targets) may result due to the deferment of the project. The matrix includes the likelihood of an event occurring and the impact of that event. The following types of factors are reviewed when calculating the risk score:

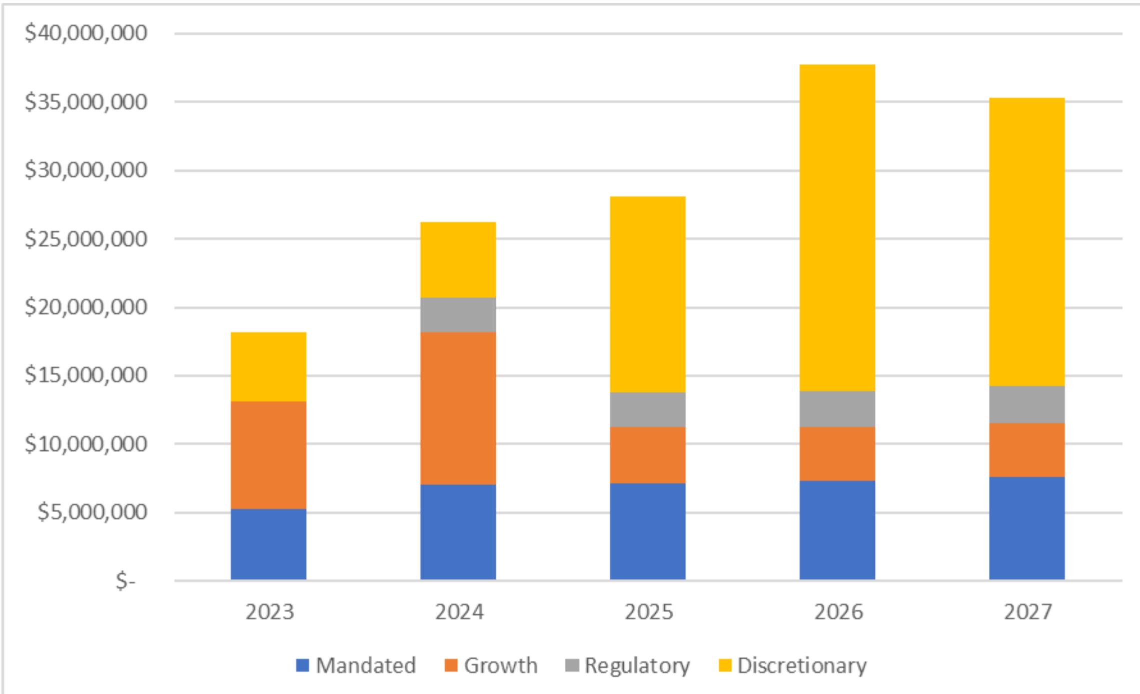
- Frequency of interruptions or failures
- Duration of outages
- Customer count of each outage
- Cost to repair the outage or failure
- Whether the failure is at the system level, such as at the substation, or is isolated to a pocket on a circuit

Table 1. Risk-Scoring Analysis

Likelihood	>Once in 100 yrs	Once in 20-100 yrs	Once in 10-20 yrs	Once in 5-10 yrs	Once in 3-5 yrs	Once in 1-3 yrs	>Once in 1 yr
Likelihood	1	2	3	4	5	6	7
Impact	Risk Value						
1	1	2	4	7	11	12	13
2	3	6	8	16	18	23	24
3	5	10	14	21	27	30	31
4	9	17	19	28	34	36	37
5	15	22	26	35	39	41	42
6	20	29	33	40	44	45	46
7	25	32	38	43	47	48	49

The Company's Capital investments planned in the near future are Bare Conductor Replacement, Grid Modernization, Underground Electric Development ("URD") replacement, and AMI, which are described above. The following chart depicts how much the Company intends to spend on Mandated, Growth, Regulatory, and Discretionary projects over the next several years.

Figure 5. Future Capital Investments 2023–2027



Q. Are the proposed capital investments sufficient to meet the current challenges?

A. Yes.

Q. In addition to capital investments, what other programs help improve system reliability?

A. Outside of Capital Investments, Vegetation Management is a significant contributor to improving system reliability. As noted earlier in this testimony, vegetation is the top driver behind the Company's reliability causes. Having a properly funded vegetation program to perform cycle trimming, hazardous tree removals, and establish proper clearances in accordance with Puc 307.10, is an important component of providing safe and reliable electric service.

Under the Commission-approved Settlement in Docket No. DE 19-064, Liberty is to maintain a four-year cycle for tree trimming and vegetation management and includes $2.220 million in base rates plus recovery of up to 10%, or an additional $0.220 million, for a total annual recovery amount of $2.420m. Unfortunately, this level of funding is no longer adequate and does not provide the Company with sufficient funding to address its vegetation obligations. Please reference the testimony of Heather Green for further explanation of challenges the Company has faced concerning Vegetation Management and the Company's proposed modifications to ensure a properly funded Vegetation Management program.

VIII. STORM RESTORATION – PLANNING & RESTORATION

Q. Please provide an overview of storm impacts over the last five years.

A. Since 2018, the Company has spent over $10 million on storms that have affected its customers. The majority of the costs arise from bringing crews from outside of New England to New Hampshire for prestaging and restoring power after the event.

In 2022, the National Oceanic and Atmospheric Administration ("NOAA") published their state climate summary[3] for New Hampshire which included statistics indicating that the temperatures in New Hampshire have risen more than three degrees since 1900 and

[3] https://statesummaries.ncics.org/chapter/nh/

precipitation since 2005 has averaged 6.8 inches more than the 1895–2004 average with the highest number of extreme precipitation events occurring between 2005–2014. The Federal Emergency Management Agency ("FEMA") made fifteen major disaster declarations between 2011–2020 with seven related to severe storms and flooding. Hurricane Sandy alone caused more than $75.0 million in economic losses.

Over the past few years, prestaging has become more crucial as the East Coast sees more intense hurricanes[4] leading to more competition among utilities for fewer contractor resources. This section of my testimony will dive further in to how the planning for major restoration efforts associated with tropical cyclones should be modified.

Q. Please explain how the Company determines if a storm event meets the major event day criteria in Puc 307.09 for reliability reporting purposes.

A. A "major event day" based on Puc 307.09 means a day during which a utility's daily system SAIDI exceeds the TMED. The TMED is a threshold value used to determine a major event day as defined in IEEE Guide for Electric Power Distribution Reliability Indices 1366-2012, Section 1.5.

Q. Does the calculation of a major event day differ from the terms and conditions of a "qualifying storm" for purposes of cost recovery?

A. Yes, the requirements of Puc 307.09 are for reporting requirements of reliability statistics and have no bearing on prestaging or qualifying storm event definitions for cost recovery.

[4] Nature Climate Change "Increasing sequential tropical cyclone hazards along the US East and Gulf coasts" https://www.nature.com/articles/s41558-023-01595-7

Q. Please describe the requirements for a weather event to be applicable for recovery within the Storm Fund.

A. There two ways that a weather event may qualify for recovery from the Storm Fund – either as a pre-staging event or as a major storm. Specific eligibility criteria apply to each category as described below:

On a daily basis, Liberty receives a weather forecast of an Energy Event Index ("EEI") for the next ten days from DTN, a weather forecasting company. The EEI provides highly detailed weather forecasts by region and zone for the four Liberty territories in New Hampshire. The forecast from DTN includes all relevant weather metrics needed to determine the severity and location of an imminent storm. The EEI ranks the impact of the storm on a scale from 1 to 5, with 5 being the most severe. DTN uses a probabilistic model to determine the forecasted impact of the storm.

Pursuant to the criteria established in Docket No. DE 13-063, pre-staging costs can be recovered through the Storm Fund if the weather event had a "high" (greater than 60% based on the forecast) probability of reaching "Level 3" or higher, according to the EEI.

Specifically, the Settlement Agreement in Docket No. DE 13-063[5] provides:

> The Company shall be entitled to recover planning and preparation activities in advance of severe weather if the weather forecast for the event shows a Schneider Electric Event Index ("EII") level of 3 or greater with a high probability of occurrence. The activities for which the Company may seek recovery include prestaging of crews,

[5] The Settlement Agreement was marked as Exhibit 9 in Docket DE 13-063; see Exhibit 9 at 7.

> standby arrangements with external contractors, incremental compensation of employees, and other costs that may be incurred to prepare for a qualifying major storm.[6]

For those events that do not meet the criteria for a pre-staging event, they may still be considered a Major Storm eligible for recovery through the Storm Fund if certain other criteria are met. A Major Storm is defined as an event that results in either (a) 15% or more of Liberty's retail customers being without power in conjunction with more than 30 concurrent troubles, or (b) more than 45 concurrent troubles during the event.

Q. Please describe what the EEI levels mean.

A. The EEI data provides the Company with a confidence level or a probability of changes to the forecast. For example, if the Company received a level three with medium confidence for wind gusts greater than 45 mph for any given day, that is translated to a 30–60% probability that the forecast will change, not a 30–60% probability that the winds will exceed 45 mph. Because these EEI levels are not a forecast of the event, but merely a probability of a change in the forecast, prestaging can be quite difficult when preparing for tropical systems.

Q. Provide the total storm-related costs for the past five years.

A. The table below provides the total storm costs by year over the past five years.

6 Id.

Table 2. Historical Storm Costs

Year	Prestaging/ Qualifying Expense	Non-Qualifying Expense	Vegetation Costs	Capital	Total
2018	$ 2,870,481	$ 795,565	$ 585,269	$ 201,486	$ 4,452,800
2019	$ 1,017,046	$ 288,462	$ 171,473	$ 588	$ 1,477,568
2020	$ 704,707	$ 325,230	$ 214,649	$ 28,671	$ 1,273,257
2021	$ 534,064	$ 992,949	$ 456,874	$ 13,648	$ 1,997,536
2022	$ 425,242	$ 566,414	$ 360,769	$ 6,927	$ 1,359,353
Total	**$ 5,551,540**	**$ 2,968,619**	**$ 1,789,034**	**$ 251,320**	**$ 10,560,513**

Q. What modification is the Company proposing related to prestaging?

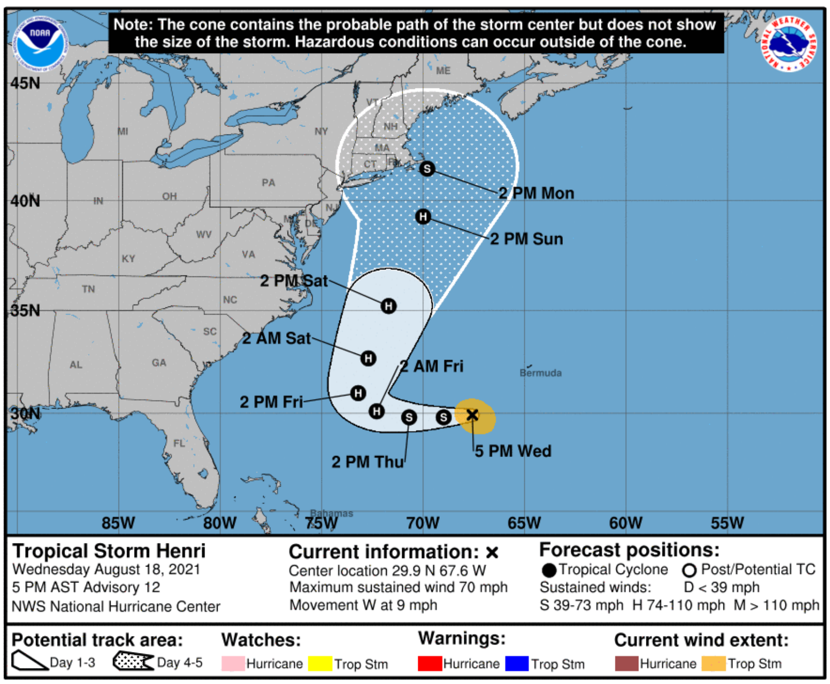
A. The modification the Company is proposing relates to tropical cyclones, which historically have become tropical storms and hurricanes. When a tropical cyclone forms, the National Hurricane Center ("NHC") will release the probable path of the tropical cyclone, referred to as the Cone of Uncertainty. When Liberty's service territory is within the Cone of Uncertainty, the Company must prepare for the possible impact of the tropical cyclone. Preparation takes many resources and time. Many of the resources, such as bucket trucks, linemen, and restoration equipment, come from the Company's affiliates or contractors located a distance from Liberty's service territory. Other utilities within the Cone of Uncertainty also prepare for the tropical cyclone causing competition for similar resources. This preparation must occur early due to the time necessary for the resources to arrive and prepare. If the tropical cyclone alters its path or is downgraded, the tropical cyclone may not be defined by DTN as a weather event and the Company cannot recover costs associated with preparedness. But the Company is placing its customers at risk if the tropical cyclone is impactful, and the Company is not prepared. Further, if the Company delays preparation, resources – if even available – must travel to

Liberty's service territory, and restoration may be significantly longer due to only having internal crews. Therefore, due to the need to be proactive and pre-stage, the Company is requesting to recover all prestaging costs if the Company's service territory is within the Cone of Uncertainty, as released by NHC for a tropical cyclone.

Q. Can you provide examples of when the Company found itself in the Cone of Uncertainty?

A. In 2021, the Company was in the Cone of Uncertainty for Hurricane Henri. The forecasted path for Hurricane Henri was to make landfall in the Northeast in the general area of Long Island, NY, to the Gulf of Maine. As a result, all utilities within the Cone were preparing and securing contractor line crew resources. The Company is part of the North Atlantic Mutual Aid Group ("NAMAG") and utilized this resource to request additional mutual aid in preparation for this event. Unfortunately, no resources were available through this process as all utilities that are members of NAMAG were subject to potential impacts from Hurricane Henri. The Company was able to request resources from its affiliate in Missouri. The charts below show the significance of the forecast. At 120 hours (5 days) out, the storm was predicted to possibly hit off Cape Cod, Massachusetts. At 72 hours (3 days) out, the storm was predicted to hit Rhode Island as a Category 1 hurricane and move directly north through Massachusetts into New Hampshire with hurricane warnings issued for southern New England the next day. Salem was considered to be in the right front quadrant of the storm where the strongest winds and gusts live.[7] The storm eventually lost strength at sea just before landfall and came through New Hampshire from the west with significant rainfall but limited wind. However, as of 2 a.m. Sunday, August 22, 2021 (i.e., less than 24 hours before the effects of the hurricane were predicted), hurricane warnings were still up within the Salem area in the northeast quadrant. If the track continued as expected, the effects of the storm could have been very different.

Figure 6. Hurricane Henri Cones of Uncertainty 120 Hours



[7] https://www.nhc.noaa.gov/outreach/presentations/Unit1_Basics_Hazards_L311_2022_NHC.pdf

Figure 7. Cone of Uncertainty Hurrican Henri 72 Hours

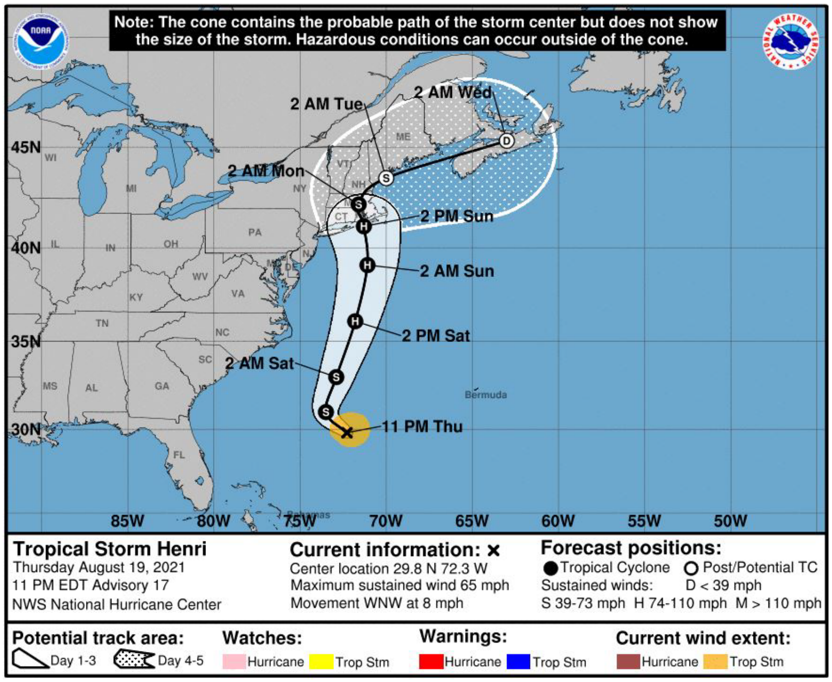
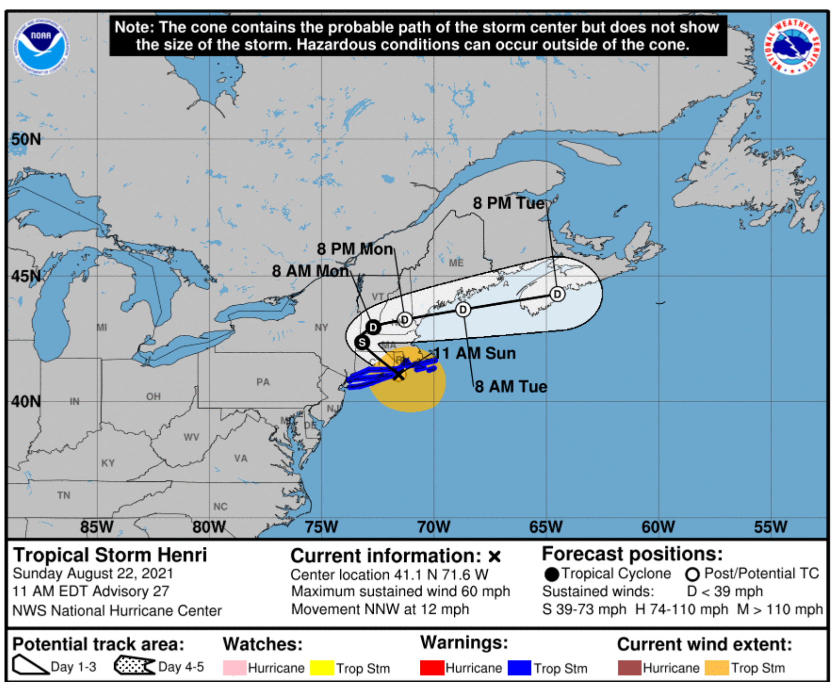


Figure 8. Cone of Uncertainty Hurricane Henri



Q. Was the Company able to recover the costs of preparedness for these examples?

A. No, the Company was not able to recover pre-staging costs under the existing threshold requirements. That is, at no point did DTN issue a Level 3 EEI, even with the NHC showing a potential Category 1 landfall in 72 hours at a location less than 90 miles away from the Salem area. Given the Level 2 EEI forecast from DTN, the Company was not able to request cost recovery for costs incurred for this storm. The cost associated with this event was approximately $450,000.

Q. Why is the Company proposing this modification?

A. Storm planning and response are critical components to providing safe and reliable service. Storm costs can be unpredictable and significant and having a proper recovery mechanism is an important measure to controlling operating expenses.

Q. Will this proposed modification impact how major storm event expenses are addressed?

A. This proposal will only impact how costs associated with the planning and response for tropical cyclones are captured. All other current cost recovery mechanisms will remain unchanged.

IX. CONCLUSION

Q. Do you believe that Liberty's proposal as outlined in your testimony will allow Liberty to continue to provide safe and reliable service?

A. Yes.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

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