STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET DE 19-064

IN THE MATTER OF: **Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities Petition for Permanent Rates**

Distribution Service Rate Case

DIRECT TESTIMONY

OF

Kurt Demmer
Utility Analyst NHPUC

December 6, 2019

Q. Please state your full name.

A. Kurt Demmer.

Q. By whom are you employed and what is your business address?

A. I am employed as a Utility Analyst in the Electric Division of the New Hampshire Public Utilities Commission (Commission or PUC). My business address is 21 South Fruit St., Suite 10, Concord, NH, 03301.

Q. Please summarize your education and professional work experience.

A. I graduated from Merrimack College in North Andover, Massachusetts with a Bachelor of Science degree in Electrical Engineering in 1987. In 2002, I received a Master's degree in Electrical Engineering and Power Systems Management from Worcester Polytechnic Institute in Worcester, Massachusetts. Since 1996, I have been a registered professional engineer in the State of New Hampshire.

In June 1988, I joined Massachusetts Electric Company as an Operations Field Engineer. In 1996, I became a Senior Engineer for Massachusetts Electric Company. In 1999, my area of responsibility expanded to include distribution planning engineering. In 2000, I accepted a position as Area Supervisor for the Salem NH area of National Grid USA and was responsible for all distribution engineering, distribution overhead/underground/substation construction, substation operations, and warehousing in the Salem/Pelham area. In 2002, I was promoted to Superintendent of Electric Operations in the Salem/Beverly/Cape Ann Massachusetts area. As Superintendent, I was responsible for distribution engineering immediate oversight, distribution overhead/underground/substation construction, substation operations, and warehousing. From 2003 to 2004, I was a project manager for a 14-mile, $19 million subtransmission 34.5kV underground distribution project consisting of manhole and duct construction housing (1) 34.5kV distribution supply circuit and (1) 34.5kV distribution circuit connecting East Beverly substation to a downtown Gloucester distribution substation. In 2005, as Superintendent of electric overhead distribution operations, I was assigned to the Merrimack Valley district area in Massachusetts. In 2008, I was promoted to Manager of Electric Operations in New Hampshire for National Grid, responsible for the operations, construction, and maintenance functions for the electric distribution organization. In 2010, I was promoted to Acting Director of Electrical Operations in New Hampshire for National Grid. In 2012, I became Director of Electrical Operations in New Hampshire for Liberty Utilities (Liberty). My continued areas of responsibility were to oversee the construction, maintenance, and operation of the electric distribution system. Since 2017, I have been employed as a Utility Analyst in the Electric Division for the Commission.

Q. What is the purpose of your testimony?

A. My testimony in this proceeding will cover numerous engineering, technical, and operational aspects that Liberty utilizes in the company's justification of capital investments as well as operational and maintenance expenses. Since planned utility capital investment is generally a product of applying the utility's load forecasting, distribution planning criteria, contingency criteria, and the utility's operating and maintenance procedures, Liberty's Least Cost Resource Integration Plan (LCIRP) plays a key role in those investments.

The first part of my testimony will examine, analyze, and compare the Liberty's 2016[1] and the 2019[2] planning criteria in the LCIRPs filed with the Commission. In addition to assessing the two LCIRP submissions, Staff will compare Liberty's planning criteria listed in its current LCIRP with other New Hampshire investor owned utilities (IOUs)[3] and the previous planning criteria from National Grid[4].

The second part of my testimony will look at Liberty's 2017 Salem Area Planning Study[5]. The Company has multiple large capital investments based on this Area Study. Rockingham Substation installation, Goldenrock substation reconfiguration, and a 115kV supply installation in the existing subtransmission supply corridor on Route 28, are recommendations that emanated from that Area Study.

The third part of my testimony will address Liberty's proposal for an increased base level spending in its vegetation management program (VMP). In addition to the increased base level spending, Liberty has also requested an increased expenditure over a 4-year timeframe for hazard tree removal.

The fourth part of my testimony will focus on Liberty's reliability indices and performance from 2005 to present as it relates to the existing Reliability Enhancement Program (REP)[6].

The final part of my testimony addresses other miscellaneous items including the 6L2/6L4 underground cable splice replacement project 8830-C42921, pole rental fees for third party

[1] Attachment KFD-1, Docket No. DE 16-097. Appendix D, Bates page 151-153
[2] Attachment KFD-2, Docket No. DE 19-120, Attachment 2, Bates page 142-158.
[3] Attachment KFD-3, Eversource Planning Criteria, Docket No. 15-248 Bates Pages 35-54. Unitil Planning Criteria, Docket No. 16-463 Appendix B Page (16) of (18).
[4] Attachment KFD-4, National Grid Distribution Planning Guide, Docket No. 16-383, Attachment Staff 8-63.1.
[5] Attachment KFD-5 Docket No. DE 19-064, Data Request Staff 5-14.d.i. Pages 7-19
[6] Initial REP was established in Order 24,777, Docket No.06-107. An extension was granted in Order No. 26,005, Docket No. DE 16-383.

attachments[7], the Company's proposal for underground line extension tariff changes[8], and the Company's interconnection tariff proposal.

Q. Have you previously testified before the Commission?

Yes. I have previously testified before the Commission while I was an employee of Liberty, and more recently, I have testified in Docket No. DE 19-111, Annual Stranded Cost Recovery and External Delivery Charge Reconciliation and Rates.

LCIRP Analysis

Q. Please provide an overview of Liberty's 2016 LCIRP planning criteria and load forecast

A. The 2016 LCIRP planning criteria submitted in Docket No. DE 16-097 outlines the distribution system design and equipment rating criteria for normal loading and N-1[9] loading conditions as it applies to distribution circuits, subtransmission lines, and substation transformers. A summary of the design criteria is described below:

During normal operation:

-Distribution circuit loading to be no more than 75% of the continuous rating of the circuit.

-Subtransmission line loading to be no more than 90% of the continuous rating of the line.

[7] Third party pole attachments include non-pole owner entities such as Comcast Communications, Segtel Inc. / FirstLight Fiber, and Charter Communications.
[8] Docket No. DE 19-064, Technical Statement of Heather M. Tebbetts (filed November 22. 2019) and Attachment HMT-CU-1, Bates pages 48 and 50.
[9] N-1 is the condition under a single or first contingency.

-Substation transformer loading to be no more than 75% of the continuous rating of the transformer.

During Single or N-1 Contingency:

-Distribution circuit peak load to be transferred to adjacent circuits with no more than 16 MWhr load at risk[10].

-Subtransmission line peak load to be transferred to adjacent subtransmission line or offload subtransmission through distribution circuit switching. Load at risk post switching to be no greater than 1.5 MW or 36 MWhr based on a maximum 24-hour restoration.

-Substation transformer peak load to be transferred to adjacent substation transformer (in the case of a two-transformer substation) or offload substation transformer load through distribution switching. Load at risk loading to be no more than 2.5 MW or 60 MWhr based on a 24 hour mobile sub[11] restoration.

Additional distribution system design criteria:

-First Contingency Emergency Design Criteria:

Wherever practical, distribution circuits shall have three circuit ties to provide greater flexibility.

Distribution circuits should be limited to 2500 customers with no more than 500 customers between each disconnecting device on the circuit.

[10] Load at Risk is the amount of load that is not reenergized during a single contingency incident during peak loading. For example, 2 MW load that is deenergized for 8 hours during peak loading is 16 MWhr peak load at risk.

[11] A mobile sub is a substation transformer on a portable flatbed, which can be rolled into the failed substation transformer location in order to reenergize the load at risk. Typically, a mobile sub can be utilized and is placed into service within 24 hours.

For a typical 10 MW distribution circuit approximately 8 MW would need to be restored in one hour with the remaining 2 MW restored within 4 hours. If the failed equipment is an underground cable, then the load at risk should be reduced to 1 MW due to the lengthy restoration timeframe.

A summary of the equipment rating criteria is described below:

During normal operation:

-Overhead conductor to be limited to 80°C for bare wire; 90°C for covered wire.

-Underground cable to be limited to a 90°C.

-Substation transformer to be limited to 0.2% loss of life and top oil temperature does not exceed 110°C.

During long term emergency operation (24 hours):

-Overhead conductor to be limited to 90°C for bare and covered wire.

-Underground cable to be limited to 130°C.

-Substation transformer to be limited to 0.3% loss of life and top oil temperature does not exceed 130°C

The forecasting methodology is based on econometric models and updated annually. It is developed on both weather normalized and weather probabilistic basis on both a system level and a Planning Study Area (PSA) level. The loading in the first year of the forecast is adjusted to the extreme weather forecast which is a 95/5 (once in 20 years) forecast. Known spot loads 300kVA or greater are added to the PSA forecast after the forecast has been determined.

Q. What is the planning criteria difference between Liberty's 2016 LCIRP and the 2019 LCIRP?

A. Overall the two LCIRP describe similar design criteria, equipment rating criteria, and forecasting methodology, however, there are additional equipment rating criteria for distribution transformers that were new to the 2019 LCIRP planning criteria. They are detailed in Attachment KFD-6.

Q. In light of the Commission's approval of Liberty's 2016 LCIRP, why is Staff continuing to analyze the LCIRP's planning criteria in this Docket?

A. At the time the 2016 LCIRP was approved, there were not enough significant capital projects that were the result of the new planning criteria to adequately evaluate the reliability and economic related impacts. The 2016 Liberty LCIRP was not approved until July 10, 2017.[12] The previous LCIRP filed in DE 12-347 was comprised of National Grid 2011 revised design criteria. Although the criteria had been revised, the impact to Liberty's capital budget was masked by the transition from National Grid to Liberty and the operational requirements of being a stand-alone utility. In Commission Order No. 26,039, the Commission analysis stated, "We agree with Staff and find that, to fully address our previous directive to 'better integrate its actual enterprise planning with its LCIRP process,' Liberty should prepare and adopt standard operating procedures for its employees and managers to integrate day-to-day and long term planning with its LCIRP. To that end, we direct Liberty to develop, in consultation with Staff, comprehensive standard operating procedures for its employees and managers to better integrate its day-to-day and long term planning with the LCIRP we

[12] Order No. 26,039, Docket No. DE 16-097

approve today." "In addition to cost comparisons of the various alternatives considered, we will require more detailed evidence of reliability, environmental, economic, and health related impacts. Liberty has the burden to meet the requirements of RSA 378:38, and to demonstrate that its planning process results in the adoption of least cost options that meet the standards articulated in RSA 378:39 by which the Commission is required to evaluate the plan."[13]

Q. What were the conditions required by the Commission placed on Liberty in order for Liberty to waive a full LCIRP submittal on July 1, 2019?

A. In Commission Order No. 26,261, the requirements for Liberty were stated as follows, "While we will allow Liberty to delay its LCIRP filing, we will nonetheless require a more limited filing by the Company on or before July 15, 2019. The purpose of this filing will be to ensure that Liberty is adhering to certain commitments made in its prior approved LCIRP. Our approval of Liberty's 2016 LCIRP contained specific deliverables and we will require updates of those in Liberty's July 15 filing, as follows:

- Confirmation that the utility is currently following the process of system planning using established procedures, criteria, and policies outlined in its 2016 LCIRP, and achieving the objectives included its 2016 LCIRP.
- Copies of adopted standard operating procedures for employees and managers integrating day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning.". [14]

[13] Order No. 26,039, Docket No. DE 16-097, page 5-6.
[14] Order No. 26,261, Docket No. DE 16-097, Page 6.

Q. How has Liberty attempted to satisfy the deliverables required by Commission Order No. 26,261?

A. Liberty submitted a 2019 version of its limited LCIRP filing on July15, 2019. As previously discussed, the 2019 LCIRP is very similar to the 2016 LCIRP with the exception of various distribution transformer load rating revisions. Although the distribution transformer load ratings criteria appears to have been reduced from the previous National Grid equipment rating[15], the short term capital budget impact due to this change is relatively minor as compared to the subtransmission line, substation transformer, and distribution circuit planning criteria that was lowered in the 2016 LCIRP. In aggregate, however, as these distribution transformers are assessed and replaced due to the lower equipment rating, the capital impact may become more significant considering the quantity of distribution transformers that are installed and replaced annually.

Other items that were submitted in the 2019 limited LCIRP that are in addition to what was submitted in the 2016 LCIRP is a comprehensive set of Distribution Construction Standards for overhead and underground equipment, electric operating procedures for distribution, strategy documents (DAS-1 through DAS-15), and reliability based review processes and identification tools (DAM-012 and DAM-016). These documents, numbered DAS-1 through DAS-15 provide Liberty employees guidance on Liberty's asset management strategy on numerous distribution field assets.

Q. **Do these documents and associated testimony satisfy the requirements of Commission Order No. 26,261?**

[15] Presently Staff is assessing the 2019 LCIRP in Docket No. 19-120.

A. No. The Company's new distribution transformer rating criteria is a deviation from its previous criteria, and in fact demonstrates that the Company is *not* currently following the process of system planning using established procedures, criteria, and policies outlined in its 2016 LCIRP.

Furthermore, the Company's filing in Docket No. DE 19-120 does not include other important documentation which would have shown whether the Company's standards and operating procedures for employees and managers integrate day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning.

Q. Please describe the additional documentation that would be necessary to evaluate whether the Company has adopted standard operating procedures for employees and managers that are consistent with the Company's least cost planning objectives.

A. As part of the construction standards, operating policies, and procedures, there are also substation maintenance procedures (SMP) and substation maintenance standards (SMS). These procedures and standards, which were developed by National Grid to adequately maintain substation assets, are an essential resource for Liberty to benchmark asset performance and gauge substation asset condition. Coupled with an industry recognized software such as Cascade, operational and maintenance requirements can be initiated and tracked in a time based, condition based, or activity based function.

Q. What is the significance of not receiving all of the 2019 LCIRP deliverables at this time?

As stated in Order No. 26,039, it is imperative for the Company to include adopted standard operating procedures for employees and managers integrating day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning. The lack of updated or adopted SMS and SMP indicates a disconnect between substation asset evaluation and the least cost planning process. I will defer this discussion until the second part of my testimony.

Q. How does Liberty's Planning Criteria and load forecasting compare to other New Hampshire IOUs and the National Grid 2011 planning criteria?

A. Refer to Attachment KFD-1 and KFD-4. Note: Eversource's LCIRP and planning criteria depicted are based on the 2015 LCIRP submission, as Staff is still reviewing Eversource's recent 2019 LCIRP submission.

For quicker comparative analysis, please refer to Table 1 below:

Table 1

Comparison of Planning Criteria and Forecasting Methodology

Liberty Utilities	National Grid	Eversource (See Note)	Unitil
Normal Operations			
Distribution feeders to remain within **75%** of normal ratings.	Distribution Feeder to remain within **100%** of normal ratings	Distribution Feeder to remain within **100%** of normal ratings	Distribution Feeder to remain within **100%** of normal ratings
Subtransmission lines to remain within **90%** of normal ratings.	Subtransmission lines to remain within **100%** of normal ratings	Subtransmission lines to remain within **100%** of normal ratings	Subtransmission lines to remain within **100%** of normal ratings
Substation transformers to remain within **75%** of normal ratings.	Substation transformers to remain within **100%** of normal ratings	Substation transformers to remain within **100%** of TFRAT ratings with an 85% TFRAT rating identification	Substation transformers to remain within **100%** of normal ratings
First Contingency (N-1) Operations			
For loss of a distribution feeder, with no more than **16MWhr** load at risk during peak loading	For loss of a distribution feeder, with no more than **16MWhr** load at risk during peak loading	N/A	N/A
For loss of a subtransmission line, load at risk after switching is no more than **1.5 MW**. No more than **36 MWhr** load at risk during peak loading	For loss of a subtransmission line, load at risk after switching is no more than **20 MW**. No more than **240 MWhr** load at risk during peak loading	For loss of a subtransmission line, load at risk after switching is no more than **30 MW**. No more than **720 MWhr** load at risk during peak loading	For loss of a subtransmission line, load at risk after switching is no more than **30 MW.** No more than **720 MWhr** load at risk during peak loading
For loss of a substation transformer, load at risk after switching is no more than **2.5 MW**. No more than **60 MWhr** load at risk during peak loading	For loss of a substation transformer, load at risk after switching is no more than **10 MW**. No more than **240 MWhr** load at risk during peak loading	For loss of a substation transformer, load at risk after switching is no more than **30 MW**. No more than **720 MWhr** load at risk during peak loading	For loss of a system supply substation transformer, load at risk after switching is no more than **30 MW**. No more than **720 MWhr** load at risk during peak loading
Other First Contingency (N-1) Design Criteria			
In general, and whenever practical, each distribution feeder should have 3 feeder ties to adjacent circuits	Circuits shall tie to neighboring circuits as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible	N/A	N/A
Distribution circuits should be limited to 2,500 customers and sectionailed such that the number of customers does not exceed 500 or 2,000 kVA of load between disconnecting devices	N/A	N/A	N/A
Load Forecasting Methodology			
Load forecast is based on econometric models and updated annually. It is developed on both weather normalized and weather probabalistic basis on both a system level and a Planning Study Area (PSA) level. The following year (Year 1) forecast is based on an extreme weather forecast which is a 95/5 forecast. Known spot loads are added to the PSA forecast after the forecast has been determined.	Load forecast is based on econometric models and updated annually. It is developed on both weather normalized and weather probabalistic basis on both a system level and a Planning Study Area (PSA) level. The following year (Year 1) forecast is based on an extreme weather forecast which is a 95/5 forecast. Known spot loads are added to the PSA forecast after the forecast has been determined	The maximum Peak Load Forecast shall be based upon the highest recorded peak within the previous five years where consecutive days of 17 cooling degree days occurred. Each Operating area has separate peak load forecast based on spot load increases and New Hampshire Coop / Unitil Load forecasts	Load forecasts are developed using a linear trend regression model that correlates a 10-year history of daily peak load versus daily average temperature and humidity. A Monte Carlo simulation is utilized to produce a range of peak load possibilities. Peak Design load is used for system infrastructure adequacy and contingenciy studies. Peak Design load is a 90/10 forecast.

Q. Is there a concern with Liberty's existing planning criteria?

A. Liberty addresses the change in design criteria in its 2016 and 2019 LCIRPs. It states "Liberty Utilities has refined the distribution planning criteria to better fit Liberty's strategy and scale of facilities. These refinements …..reflect Liberty's strategy of having sufficient capacity available to meet changes in demand, including new customer demand, to improve operations during emergency conditions, and to allow more time for the planning, analysis and construction, as needed, of new facilities. In addition the refinements reflect the operating parameters of Liberty's smaller distribution footprint and resource base."[16] Liberty's scale of facilities, similar to other NH IOUs is proportional to its customer base. Less customers typically equate to less distribution circuits, substations, and resources. Conversely, as the customer count increases and load increases, the distribution system that serves those customers also increases. This assumes a similar mix of geographical topography, customer class, and load density (i.e. rural vs. urban density). Liberty, Eversource, and Unitil have both rural and urban areas. Liberty's design criteria is significantly lower for normal loading than other NH investor owned utilities. Adopting a "take action" step at 75% rather than 100% of the equipment's continuous rating equates to a premature replacement of distribution and substation equipment, which is not necessary as the equipment is rated for 25% more loading.

Liberty's assessment of the lowered design criteria to allow more time for planning, analysis, and construction of new facilities does not align with Liberty's PSA forecast at the system level or township level. Liberty's Final Seasonal Peak Forecast 2018-2034 dated January 2019 lists a summary of results for Liberty's NH service territory. Table 1 indicates a -0.42% average growth rate for 2013-2017 summer weather adjusted peak loads. Table 2 indicates a 0.36% average load growth rate for 2020-2024 summer peak loads assuming normal weather. The largest average load growth for 2020-2024 at the township level is 1.04% average load growth rate for 2020-2024 summer peak loads assuming normal weather in the Derry Township.[17] There are spot loads 300kVA and larger that Liberty adds to the

[16] Docket No. DE 19-120 Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities Least Cost Integrated Resource Plan. Attachment 2, Bates page 0142.
[17] Attachment KFD-6. Docket No. 19-120, Staff Data Request 1-3a3.

future forecast when planning load forecasts annually, however considering that past spot loads are now embedded in the historical load growth, spot loads typically are not significantly changing the peak loads.

Q. Part of the reasoning for the 75% design criteria under normal loading is "to improve operation during emergency conditions." Isn't that be a benefit to customers?

A. Liberty only presented qualitative statements of improved operations during emergency conditions because of the 75% design criteria. The utility did not provide any specific quantitative benefits as part of its reasoning for the 75% design criteria. If the intent is to allow more capacity to switch loads during a first contingency event on a circuit, then the utility is creating a redundancy or a buffer that will not be utilized a majority of times. Contingency events that impact an entire circuit occur infrequently. Liberty and other NH IOUs are installing more sectionalizing devices on circuits to mitigate exposure or load at risk. Moreover, most circuits have normal and emergency ratings. Depending on the asset that is limiting the normal continuous rating, the emergency rating of the circuit is usually significantly higher than the normal loading. Circuits that are utilized to restore power to adjacent circuits use the emergency rating of the circuit. There are a number of cost effective measures that Liberty can utilize that will mitigate contingency issues without creating a 25% redundancy in its equipment rating.

Q. Are there other criteria that Liberty should reevaluate as part of the normal loading concerns?

A. Liberty's equipment rating criteria also is more conservative than National Grid and the other NH IOUs. The Long Term Emergency (LTE) load rating relies on the type of asset that is limiting the circuit as well as the duration. For example, the LTE load rating for overhead conductors is based on a 24-hour duration with an elevated temperature of the conductor not to exceed 90°C, however, bare wire can experience a higher temperature. For circuits which the LTE rating is based on an overhead conductor, they may have an increased LTE rating and therefore provide additional capacity for restoration during a first contingency event. There are factors that may limit the temperature of the bare conductor such as pole top insulator temperature restrictions and clearances to other conductors as the conductor sag increases. A higher temperature for an increased LTE rating for applicable circuits during these contingencies may result in less load at risk and fewer requirements to upgrade the infrastructure.

Q. Is there a way to address the capacity redundancy in normal loading and accurately reflect LTE equipment ratings?

A. Staff recommends that Liberty change the existing 75% "take action" criteria and use the 75% as a "take notice" criteria. The change will allow planners and engineers ample time to identify a future risk and plan accordingly. A "take notice" identified asset will be on an annual watch list to ensure that there is sufficient time to mitigate or eliminate a future issue if or when the asset approaches 100%. The second part of Staff's recommendation is to reduce the LTE rating to match the contingency violation as well as evaluate the limiting asset for increased temperature capabilities.

Q. Once identified through the planning criteria, how does Liberty prioritize its system deficiencies?

A. Prioritizing system deficiencies correctly is a key component in the capital planning process once a deficiency is identified. Liberty uses a scoring matrix in order to rank the relative risk of a deficiency. Liberty points out that it is not a decision making tool but rather a decision support tool in measuring and prioritizing risk. Risks are evaluated based on two criteria: (1) The impact or consequence of the risk; and (2) the likelihood that such impacts will occur.[18]

Q. Does Staff have any concerns regarding the application of the risk criteria as it relates to deficiency identified assets?

A. Yes, please see Attachment KFD-7. Risk assessment, if done manually, can be difficult to capture all of the parameters that should go into a risk based support tool. After reviewing Liberty's response, Staff disagrees with the determination of the likelihood of an event. Staff requested Liberty in the last Technical Session for Docket No. DE 19-120, Liberty's LCIRP on November 26, 2019, clarify the determination in the likelihood of a first contingency distribution circuit event. The distribution circuit's load at risk was not an identified deficiency (≥ 16 MWhr) until 2022. Liberty's interpretation is that the likelihood of that circuit first contingency violation was a 5 since the time to failure is a "once in 3-5 years."

Q. What is Staff's interpretation of the likelihood of a first contingency event?

A. A distribution feeder first contingency violation is based on a worst case scenario. The entire feeder needs to experience an outage on the circuit's peak load day and hour. Most

[18] Attachment KFD-7, Docket No. DE 19-064, Data Request OCA 4-6 and Attachment OCA 4-6.

distribution circuits in Liberty's service territory are summer peaking circuits, typically peaking at approximately the same day as the system peak. By way of example, let's assume there are 3 heat waves that summer period or approximately 10 days a year. The circuit's 5 year average SAIFI[19] (CKAIFI) is 0.5. The average frequency of outages on that circuit is once every two years. If the distribution feeder is at or under its continuous normal rating and has been properly maintained, the probability of a failure is (10/365) * (0.5) or 1.36%. The probability of   Liberty's forecast methodology is based on a first year forecast adjustment using a 95/5 extreme peak forecast. A 95/5 forecast is defined as a 1 in 20 year forecast. The probability of exceedance is 5%. There is also a 5% chance that you will meet that extreme peak. Therefore, there is a 5% chance that a 1.36% probable event will occur or a 0.06 % probability that the event will occur. The above calculation is somewhat crude and one could argue that there are other factors that could raise the probability, *i.e.* vehicular damage, however using an order of magnitude, the likelihood of the event is extremely small. The same calculation for probability or likelihood can also be applied to substation transformers and subtransmission supply lines. Although the impact of a first contingency event is significantly greater with a substation transformer or subtransmission supply line, the likelihood is decreased further due to the configuration, maintenance, and access of those assets.

Q. What is the correlation between the risk assessment and Liberty's design criteria?

Liberty presently does not utilize risk assessment software, however the MW and MWhr load should, at a minimum, reflect the actual risk and impact that a substation transformer,

[19] SAIFI is the System Average Interruption Frequency Index. It can be measured at the system level or the circuit level (generally noted as CKAIFI). It is the number of outages an average customer experiences.

subtransmission line, and distribution feeder contingency presents. The existing Liberty design criteria is more conservative than its predecessor, National Grid, and is far more conservative than the other NH IOUs.

Q. What is Staff's recommendation for risk evaluation in Liberty's design criteria?

A. Liberty's design criteria for the assets that have the probability for a larger impact should be consistent with the other NH IOUs while still evaluating the actual probability and impact of each significant contingency event. The 30MW/720 MWhr load at risk should be considered as a first step. Mitigation of contingencies such as portable transformers, emergency portable generation, and access enhancement should be considered before significant capital investment is employed.

Q. Does this recommendation extend to the 16MWhr first contingency design criteria for distribution circuits?

A. No, it does not. The impact and likelihood of a distribution circuit outage does not warrant a specific load at risk criteria. Distribution circuits vary too much in their layout and level of complexity to provide backup configurations, criticality of load, and circuit design. The 16MWhr criteria is a guideline and should not be part of a criteria that requires a costly solution to resolve. In its 2016 LCIRP, Unitil states "To provide continuity or immediate restoration of service to all portions of system load for all reasonably foreseeable contingencies requires fixed infrastructure with spare capacity or redundancy for each element. This level of design may be inefficient and cost-prohibitive to cover the contingent loss of certain major elements. The loss of limited portions of system load for limited periods of time may be tolerated under defined circumstances as part of prudent, cost-effective alternatives to fixed infrastructure[20].” Staff agrees with that position.

2017 Liberty Utilities Salem Area Study

Q. What is the Salem Area Study and why was it performed?

A. The Salem Area Study was undertaken as part of the forecast and planning process. A 15-year forecast is developed annually with modeling guidelines contained in Liberty’s 2016 and 2019 LCIRP. The Salem area planning study identifies deficiencies due to existing loading and future load growth concerns. In this instance, there were four significant issues identified as significant factors in the Company’s need to perform this Area Study. Liberty identified them as follows[21]:

1. During a first contingency event (N-1), loss of the subtransmission supply to Spicket River substation in Salem, the load at risk at system peak violates the Liberty planning criteria (91MWhr, 7.6 MW load at risk post contingency switching).
2. During a first contingency event (N-1), loss of the Goldenrock substation transformer (owned by National Grid), the load at risk at system peak violates the Liberty planning criteria (288 MWhr, 12 MW load at risk post contingency switching).
3. Barron Ave Substation and Salem Depot substation need to be retired due to asset condition of the substations as well as maintenance and operating issues at both substations.
4. The proposed business park development (Tuscan Village) with a load range of 14 MW-17 MW.

[20] Docket No. 16-463, Unitil Energy Systems, Inc. 2016 LCIRP Report, Appendix B, page (11) of (18)
[21] Attachment KFD-5 (Data Request Staff 5-14.d.i). Page (7) and (8) of (213)

Q. What is the 2017 Salem Area Study recommendation?

A. The Planning Study's recommendation contains three phases:

Phase 1: National Grid to install a 115kV to 13.2kV substation transformer at Goldenrock in the spare 23kV bay. Liberty would install (3) 13.2kV circuits in the spare bay fed from the new National Grid transformer. An underground ductbank would be constructed for the circuits to exit Goldenrock substation. This new capacity would alleviate the first contingency loading concerns at Spicket River Substation and pick up the load presently being served by Barron Ave circuits. This would allow the retirement of the Barron Ave substation.

Phase 2: Liberty would purchase and install the Rockingham substation at Tuscan Village. National Grid would install (2) 115 kV transmission lines from Goldenrock substation to the proposed Rockingham substation located in Tuscan Village. National Grid would install two115kV to 13.2kV transformers. Liberty would install eight 13.2kV circuits; three circuits to pick up existing load presently being served by Salem Depot substation, three circuits to alleviate general load in the area and address any Liberty planning criteria loading or first contingency violations, and two circuits to feed the Tuscan Park load. This would allow for the retirement of the Salem Depot substation.

Phase 3: National Grid to install a second 115kV to 13.2kV substation transformer at Goldenrock and remove the existing 115kV to 23kV substation transformer. Liberty would install four 13.2kV circuits in the substation bay formerly occupied by the two 23kV supply lines that fed Barron Ave, Olde Trolley, and Salem Depot substations. The four additional 13.2 circuits will provide further contingency support to Spicket River circuits and pick up existing load presently being served by Olde Trolley substation. This would allow the conversion of the Olde Trolley substation to a switching and regulation station

Q. Is Staff aware of any changes to this recommendation?

A. The Direct Testimony of J. Rivera, A. Strabone, and H. Tebbetts[22] states that Liberty was going to construct and own the 115kV line from the Goldenrock substation to the proposed Rockingham substation. In order to avoid the line being classified as transmission, Liberty petitioned the Northeast Power Coordinating Council Inc. (NPCC) for E-1 exclusion. In addition to Liberty owning the two 115kV lines, Liberty also decided to purchase, install, and maintain the two 55MW substation transformers at Rockingham substation. This would be the first 115kV to 13.2 substation transformer Liberty NH has owned.

Q. What is Staff's position on Liberty owning and operating two 115kV lines and two 115kV to 13.2kV substations transformers?

A. As stated earlier in my testimony (p. 11), Staff has not received any SMS or SMP submittals from Liberty as part of Docket No. 19-120 Liberty LCIRP submittal. Staff cannot assess Liberty's proficiency or knowledge in 115kV distribution construction (Construction Standards), operations, or maintenance of these lines (EOPs). Additionally, Staff cannot assess Liberty's operational or maintenance knowledge of 115kV to 13.2kV 55MW substation transformers. Staff has not received any procedures or standards in Docket No. DE 19-120 LCIRP submittal to use in making such an assessment.

[22] Docket No. 19-064, Direct testimony of J. Rivera, A. Strabone, and H. Tebbetts, Bates p. II-189

Q. Is the Spicket River substation first contingency event (N-1) listed as a violation of Liberty's planning criteria still valid for 2019 actual peak loads?

A. Liberty's Spicket River substation is presently fed by a radial 23kV line from Methuen Massachusetts. In the event of loss of the 23kV line, three distribution feeders; the 13L1, 13L2, and the 13L3 are affected. Staff inquired about the load at risk that was in violation of Liberty's planning criteria in 2016/2017 timeframe. Liberty reported that the peak load at risk post contingency switching for the Spicket River substation increased from the 7.6 MW in 2016 to 11.9 MW using actual 2019 loading data.[23]. According to Liberty's planning criteria, the peak load at risk is still in violation of Liberty's planning criteria.

Q. Does Staff agree with Liberty's assessment of the 23kV subtransmission supply line risk at Spicket River substation?

A. No, Staff does not. As stated earlier in my testimony, Liberty's planning criteria for subtransmission supply first contingency peak load at risk is too conservative and is not aligned with the other NH IOUs or its predecessor, National Grid. The 11.9 MW peak load at risk post contingency switching is significantly less than the 30MW peak load at risk established by the other NH IOUs. To a lesser extent, the 11.9 MW peak load at risk is lower than National Grid's planning criteria of 20MW.

Q. Were there other factors that led Staff to question this first contingency load at risk for the 23kV supply to Spicket River?

[23] Attachment KFD-8, Docket No. 19-064, Staff Data Request TS 1-30

A. Yes, please see Attachment KFD-8. Staff also inquired about two distribution circuit ties located on the Salem/Haverhill state line. Staff questioned whether Liberty considered the use of those ties to reduce the load at risk during a first contingency event on the 23kV subtransmission supply to Spicket River. Liberty did not consider the ties in the load at risk calculation, which could significantly decrease the load at risk even further.

Q. Is the Goldenrock substation first contingency event (N-1) listed as a violation of Liberty's planning criteria still valid for 2019 actual peak loads?

A. Goldenrock Substation is a bulk substation, 115kV to 23kV, that is owned by National Grid, and supplies two-23kV subtransmission lines that ultimately feed three 23kV distribution substations; Barron Ave, Olde Trolley, and Salem Depot substations. The 23kV subtransmission supply lines also can be fed from Methuen Massachusetts, which was the original feed prior to the building of Goldenrock in 2001. In the event of loss of the Goldenrock 115kV to 23kV transformer, the load at risk is 5.1 MW, however the 5.1 MW can be transferred using post contingency switching resulting in no peak load at risk.[24] The first contingency (N-1) of the Goldenrock substation transformer is no longer a violation of Liberty's planning criteria..

Q. Liberty states that Barron Avenue substation and Salem Depot substation need to be retired due to asset condition. Does Staff agree with that assessment?

[24] Attachment KFD-9, Docket No. 19-064, Staff Data Request TS 1-31 a.

A. No, staff does not agree. Staff has inquired about Liberty's assessment of Barron Avenue and Salem Depot. In order to make an assessment that both substations have asset condition issues, two items need to be addressed.

First, an assessment needs to be undertaken by a qualified substation vendor or personnel experienced in substation refurbishment or replacement. This vendor or person will require maintenance records and test results that will inform the vendor of steps and cost required to extend the life of the assets.

Second, in order for Liberty to have maintenance and operational concerns, testing and failure records, coupled with a comprehensive maintenance scheduling and tracking system, need to show a consistent deficiency in performance, or increased maintenance costs, which would demonstrate an ongoing asset issue.

Staff inquired if Liberty had utilized a qualified vendor to provide any detailed estimates or assessments which may provide either a least cost option to mitigate or extend asset life. This would assist Liberty in making an informed decision whether to retire or rebuild these substations. Liberty did not use this resource, nor did it provide any estimate for mitigation.[25]

Q. Were there maintenance records produced by Liberty that would demonstrate significant asset performance or condition issues?

A. Staff requested Liberty to provide the last 5 years of substation inspection and maintenance records including any substation related work that arose from those inspection and maintenance activities during that timeframe.

[25] Attachment KFD-9, Docket No. 19-064, Staff Data Request TS 1-31 f.

Liberty produced the records that included both "visual and operational" records, maintenance records, and limited substation related work. In addition, Liberty also referred Staff to the asset inspection record for Barron Avenue which was part of Docket No. DE 16-383, Liberty Utility Distribution Service Rate Case, Staff data request 4-51 and attachment Staff 4-51.

After reviewing the records, Staff found no evidence of significant maintenance, repair, or performance issues[26] at Barron Ave substation or Salem Depot substation.

Q. What is Staff's finding and recommendation for the Barron Ave and Salem Depot asset assessment as noted in the 2017 Salem Planning Study?

A. Staff does not agree with Liberty's assessment of Barron Ave and Salem Depot. Both substations are adequate for the electric service they are providing.

Q. What is Staff's assessment of the Tuscan Village load estimates originally submitted in the 2017 Salem Area Planning Study?

A. In 2017, the Tuscan Village's load was originally estimated to be between 14 MW-17 MW in total. Since then, the North side of the Park has been almost built out with the majority of the North side load measured at 0.96 MW. There are some additional smaller retail establishments and residential housing that are not reflected in that actual load measurement, however, Staff would not expect to see any more than an additional 0.2 to 0.3 MW of load in the North Park in Tuscan Village.

[26] The maintenance and repair records indicate that items such as recloser, transformer bushings, or other relatively low cost repairs or replacements were addressed.

The South side of the park is a considerably larger lot and contains approximately 3-4 times the buildings that the North side contains.

The South side contains only 3 areas that have estimated service dates[27]. The remaining portion of the South side of Tuscan Village has not been identified with a firm in service date. The remaining South side of the Tuscan Village may be considerable more load, however, the 14-17 MW estimate seems extremely high to Staff. The load at this time is speculative, and is not guaranteed to be in service any time in the near future.

Q. What is Staff's overall recommendation based on the four significant issues raised in the 2017 Salem Area Planning Study?

A. First, for the Spicket River substation first contingency: The first contingency may violate Liberty's planning criteria for subtransmission first contingency peak load at risk, however, Staff feels that the load at risk is significantly less than other NH IOUs first contingency criteria. Additional evaluation using all available restoration options to reduce and mitigate the peak load at risk is also warranted.

Second, concerning the Goldenrock substation transformer first contingency: Staff determined that there is no Liberty planning criteria violation at this time.

For the Barron Avenue, Salem Depot substation asset condition: The Company has not provided substantial evidence that either substation has significant asset condition issues.

And, concerning the Tuscan Village Loading: Existing loading in the North side is 0.9 – 1.2MW (assuming build out of North side). The South side does not have enough firm in-

[27] Attachment KFD-10, Docket No. DE 19-064, Staff Response TS 1-33 and Staff Response Attachment TS 1-33.a

service dates to consider the 14-17 MW loading feasible. At this time, the majority of load is speculative.

Staff's overall recommendation is to serve the Tuscan Village Load utilizing the least cost option, which may include serving the Tuscan Village load at 23kV. The underground infrastructure would be a common installation to both 13kV and 23kV installations, however, at 23kV, the existing 13kV distribution system would not be impacted and would not create additional loading issues.

Staff does not support the recommendations in the 2017 Salem Planning Study for the reasons stated above. Therefore, Staff recommends disallowing from rate base the following projects:[28]

8830-1865	Rockingham Sub Transmission; $575,354
8830-1867	Rockingham Substation Transmission Supply – PE; $175,504
8830-1744	Goldenrock Substation; $309,324
8830-1845	Goldenrock Distribution Feeders; 16,978.

These projects are included in the list of plant investments (contained in the testimony of Jay Dudley) that Staff is recommending be disallowed from rate base. The effect of these recommended disallowances is included in the revenue requirement calculated in the testimony Donna Mullinax (which presumes these projects were closed to plant).

[28] Staff has been unable to verify whether these projects have been booked as plant is in-service or are being held in Construction Work In Progress. If these projects have not yet been closed to plant and are not in the rate base Liberty used to calculate rates in this case, then no adjustment would be is needed in this case.

<u>Vegetation Management Program</u>

Q. What is Staff's position on the existing Liberty VMP?

A. Liberty's VMP, although effective in reducing tree related SAIFI outages, has over the years, become a larger expense year to year. The key drivers in the cost increase are traffic protection and hazard tree removal. Cycle trimming has continued to provide overall good SAIFI results at a controlled cost as work planners continue to stay significantly ahead of the cycle trimming work. Liberty is requesting that the 2018 test year actual expenses, $1,944,301, be the forward level of spending in base rates. Staff agrees that the existing $1,500,000 level of funding does need to be adjusted to reflect increased costs in cycle trimming, however, Staff is concerned that the Company doesn't view the level of funding in base rates as an actual "spending" budget, but rather as a target. This difference in what the actual level of spending should be is also demonstrated in Liberty's VMP spending in recent years, and its challenge of cost control. Historically, Liberty would meet with Staff and discuss the upcoming VMP work and estimated costs prior to the end of a calendar year, for the next calendar year's planning. Staff would then make recommendations on proposed costs, generally attempting to constrain costs and assist in prioritizing Liberty's workplan. Once that meeting had finished, Liberty then proceeded to perform the work. In some years, Liberty added back in work that Staff understood had been removed by mutual agreement. In some years, Liberty has stated that it "agrees to disagree" with Staff's recommended reductions to work. In addition, Liberty has not notified Staff through the E-22 process of changes in actual spending, even when required.

Q. What does Staff recommend as far as the VMP approval process?

A. Staff recommends a base rate spending level that is viewed and adhered to as a budget. That budget amount should allow for reasonable cost overruns or underruns; Staff recommends a 10% bandwidth. This is necessary for two reasons. The first is cost control. If the Company is budgeting to a fixed amount, it will need to use cost control and prioritize the VMP budget. The second reason is accountability. Staff finds it increasingly difficult to review annual VMP overruns to ensure the funds were used prudently. Unlike a capital project that Staff can review, site visit, and correlate project objectives to the cost of the project, vegetation management activities are not as readily quantifiable. Still,, as with any capital or expense project, Liberty's VMP should be required to work within an established budget.

Q. What does Staff recommend concerning proposed costs?

A. Staff does not support the Company's proposed increase in base rates for a base rate of $1,944,301. The actual test year expenses of $1,944,301 were not reflective of the 2018 proposed work as $46,569 increase in planned cycle trimming was the result of a 2017 invoice that was not accrued for in 2017, and was paid in 2018 and $135,490 above the budgeted $400,000 for hazard tree removal was a variance due to 2016 and 2017 tree removal plans. Also, traffic control was $112,083 higher than budgeted, possibly due to the additional hazard tree removal. The Company has stated that between 2017 and 2019 there are approximately 8,000 hazard tree removals not yet removed. Although 8,000 trees seem significant, from a reliability perspective, the highest risk and high-risk trees should be addressed first. The lowest risk hazard trees, although greater in number, contribute less to reliability issues due to the reduced impact on customers. Staff recommends a $1,678,000 base rate budget for Liberty's VMP (the budget Liberty submitted for 2018 in its VMP filing). This budget includes a $400,000 budget for hazard tree removal.

In addition, Staff does not support Liberty's proposal for an incremental funding of $400,000 to address four years of backlogged hazard tree removal, but instead recommends that Liberty use the $400,000 included in the base rate budget to remove hazard trees based on priority.

REP Plan

Q. What is Staff's position on Liberty's Reliability Enhancement Program

A. REP for Liberty was established in Order 24,777, Docket No. 06-107. An extension was granted in Order No. 26,005, Docket No. DE 16-383. In the 2005-2006 timeframe, Granite State Electric d/b/a National Grid experienced a significant downward trend in SAIFI and SAIDI[29]. The objective for REP was for the utility to improve reliability to pre-2005 reliability indices. National Grid assigned a value of 1.8 for SAIFI and 126 minutes for SAIDI. Since that time, Liberty has lowered its SAIDI and SAIFI to below that original objective. In 2018, Liberty reported a SAIFI of 0.74 and a SAIDI of 121.79.

Q. What is Staff's recommendation for REP?

A. Staff is recommending ending the REP program in 2021, with calendar year 2020 being Liberty's last year for REP. Liberty's reliability indices are well below pre-2005 reliability indices. Liberty will then continue the VMP portion of this initiative through base rates and would be required to spend within the budget explained above. Staff also expects that

[29] SAIDI is System Average Interruption Duration Index which is the average duration of outage the average customer experiences annually.

Liberty will be looking at reliability from a more holistic viewpoint in the Grid Mod proceeding and subsequent IDPs.

<u>Miscellaneous</u>

Q. What is Staff's position on the 6L2/6L4 underground cable splice replacement project 8830-C42921?

A. The 6L2/6L4 cable splice replacement project was a result of incorrect installation of the splices when they were originally installed (workmanship issues). In 2017, Liberty replaced all of the splices and capitalized the job. Cable splices are a minor plant item and are charged to the underground cable when it is first installed, in this case 2010. The replacement of a minor plant item is an expense, not capital. The major plant was not replaced at the same time, therefore the replacement of the splice is an expense. The Company stated that that the splice is a capital item since the item extends the life of the underground conductor and therefore can be considered a capital plant item under FERC accounting[30].

In Staff's view, this is incorrect. A splice does not extend the life of an underground cable, it merely maintains the cable's existing life. The Plant Investment Procedure – 613 is also incorrect. An underground H splice is not considered a disconnecting device as the splice cannot be disconnected live, nor can the splice be left disconnected and/or reenergized. A splice is not a disconnecting device.

Q. What is Staff recommending in project 8830-C42921?

[30] Attachment KFD-11, Docket No. 19-064, Staff Data Response TS 2-9 and TS 2-9 f.1.

A. Because in Staff's view, this project should have been expensed in 2017, Staff recommends that this project be remove from rate base.

Q. Please describe the Pole Rental Fee and Staffs concerns.

A. Please refer to Attachment KFD-12.

Pole rental fees are fees that are incurred by third party attachers on the pole. The pole owners charge rent to these parties and reserve the right to change the rent to reflect pole maintenance costs. Liberty had been using the same rental fee since the third party had initially attached to the pole. Since the fees can offset maintenance costs, reviewing and updating the rental fee annually would allow for rental fees that more closely reflect actual costs, which would benefit all ratepayers.

Q. What does Staff recommend in Liberty's handling of the pole rental fee?

A. Staff recommends that Liberty update the pole rental fees on an annual basis and bill its third party attachers the updated fee. .

Q. What is Staffs position on the recently proposed tariff change in underground service?

A. This request is a late notice request to change the tariff rates in the underground service cost per foot; included in a Technical Statement of Heather M. Tebbetts filed November 22, 2019.

Q. What does Staff recommend in this proposed tariff change in underground service?

A. Due to the late filing, Staff has not had an adequate opportunity to investigate Liberty's concerns and proposed changes. Staff recommends that the tariff provisions for underground service remain as it is now.

Q. What did the Company propose regarding interconnection fees?

A. For systems greater than 10 kW, they proposed hourly supplemental review fees based on the size of the distribution system. According to the Company, these proposed fees are similar to those charged by Eversource Energy.

Q. What does Staff recommend regarding the proposed interconnection fees?

A. Staff appreciates the Company's approach to propose consistent interconnection fees across the state; however, Staff believes that the interconnection working group proposed in the grid modernization docket is a more appropriate place to discuss statewide interconnection fees and therefore opposes Liberty's proposed changes in the case.

Q. Does this conclude your testimony?

A. Yes