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.

<u>LCIRP Analysis</u>

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.

<u>2017 Liberty Utilities Salem Area Study</u>

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.

Vegetation Management Program

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.

Miscellaneous

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

Appendix D - Distribution Planning Criteria Summary

1.0 Introduction

This document summarizes the Distribution Planning Criteria and Strategy that will be used by the Engineering Department of Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company") to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA").

2.0 Equipment Ratings

Thermal limits are recognized for all system elements in conducting planning studies. The current in equipment and lines are limited so that voltage drops are held to reasonable values; so that conductors will not be severely annealed or damaged; so that switches, connectors, etc. will not be overloaded and that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures, 2) load cycles, 3) wind velocities, and 4) potential loss of life of equipment.

Liberty's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

Figure D-1 summarizes the Equipment Rating criteria:

Figure D-1. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**
Normal	Continuous	• The maximum value for normal peak loads on all new and rebuilt feeders • Temperature limit for 100% ampacity for normal operating conductor is <u>176°F/80°C for bare conductors</u> and <u>167°F/75°C for spacer cable, tree wire, & covered conductors</u>	Continuous	• Maximum loading that does not cause the conductor temperature to exceed its design value <u>at any time</u> during a 24-hour load cycle • Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	• Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or • The Top Oil Temperature <u>exceeds 110 °C</u>, or • The Hot Spot Copper temperature <u>exceeds 180 °C</u>
LTE	24 Hours	• The absolute maximum ampacity allowed for a given conductor and <u>should not be exceeded at any time</u>. • Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is <u>194°F/90°C</u> for <u>both bare and spacer cable, tree wire, & covered conductors</u>	100 - 300 Hours	• Maximum loading that does not cause the conductor temperature to exceed its design value <u>over several consecutive</u> 24-hour load cycles. • Emergency cable ampacities are based on 130° insulation operating temperature.	1 - 300 Hours	• Level for the peak hour <u>with the emergency load added</u> in the 24-hour load cycle causes a cumulative (24 hour) <u>3.0%</u> loss of Transformer life, or • the Top Oil Temperature <u>exceeds</u> <u>130 °C</u>, or • the Hot Spot Copper temperature <u>exceeds</u> <u>180 °C</u>
STE	As Needed	• Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	• Maximum loading that does not cause the conductor temperature to exceed its <u>allowable emergency value</u> <u>at any time</u> during a 24-hour load cycle. • Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	• The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) <u>3.0%</u> loss of Transformer Life, or • a hot spot copper temperature <u>exceeding</u> <u>180°C</u>. • Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

3.0 <u>Planning Criteria</u>

For normal loading conditions on distribution feeders and transformers, the planning criteria is based on facilities to remain within 75% of normal ratings at all times. For sub-transmission lines, facilities are to remain within 90% of normal ratings.

For N-1 contingency situations, the planning criteria is based on interrupted load returning to service within a reasonable time via system reconfiguration through switching, installation of temporary equipment, such as mobile transformers or generators, and/or by repair of a failed device. Where practical, switching flexibility is integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Figure D-2 shall guide loading and contingency planning on the distribution system:

Figure D-2. Distribution System Planning Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

Application of these criteria will result in somewhat less load at risk than previous criteria which generally limited load at risk to between 4 and 20 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the new criteria for both normal and N-1 contingency conditions are shown in Figure D-3:

planned, measured, and operated with the objective of providing electric service to customers under system intact conditions (i.e., "normal") and first contingency conditions ("N-1").

1.2 New Planning Criteria

Since the purchase of the New Hampshire electric assets from National Grid in 2012, Liberty Utilities has refined the distribution planning criteria to better fit Liberty's strategy and scale of facilities.[1] These refinements, such as reducing the normal operating ratings limit from 100% to 75% on feeders and transformers and from 100% to 90% on supply lines, 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.

Table 2 shows an estimate of additional facilities that may be required as a result of new planning criteria for the entire system over the next 15 years, based on the results of a sample of areas.

Table 2. Additional Facilities as a Result of New Criteria

Asset	Additional Quantity Required
Transformers (at existing or new substations)	0
Sub-Transmission Lines	0
Distribution Feeders	7

The new criteria will be scaled in over a 15-year period, and initially, will be applied to new installations and/or significant rebuilds initially. The criteria shall be reviewed and refined further, as needed, to reflect any major changes in standards or operating criteria.

2.0 PLANNING CRITERIA SUMMARY

The planning criteria are used to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA"). The planning criteria are a critical input to identifying system deficiencies in Liberty's distribution planning process. See Figure 1 for the planning process. The planning criteria described

[1] Attachment B provides a summary of the changes to Liberty's new criteria from the previous criteria under National Grid.

in this document provides the framework to identify normal and emergency conditions, the acceptable equipment ratings under these conditions, and the corrective action required when the criteria is exceeded. For normal loading conditions, the planning criteria are based on feeders and transformers to remain within 75% of normal ratings at all times and supply lines to remain within 90% of normal ratings at all times.

For N-1 contingency situations, the planning criteria is based on interrupted load returning to service via system reconfiguration through switching, installation of temporary equipment, such as mobile transformers or generators, and/or by repair of a failed device. Where practical, at least three feeder ties are planned for each feeder for switching flexibility and are integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Table 3 shall guide planning on the distribution system:

Table 3. Distribution System Design Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

3.0 DESCRIPTION OF THE DISTRIBUTION SYSTEM

Liberty's distribution system consists of lines and equipment operated at a voltage at or below 23 kilovolts ("kV"). The components of the distribution system include: distribution substations, sub-transmission lines, and distribution circuits or feeders.

3.1 Distribution Substations

The distribution substations within Liberty Utilities are a mixture of stations with one, two or three or more transformers. A typical substation consists of 23/13 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders. Some distribution substations are supplied by the 115 kV circuits and are jointly owned by Liberty Utilities and National Grid. Liberty Utilities and National Grid maintain approximately 16 distribution substations containing approximately 26 power transformers in the Liberty

Utilities' service territory. Liberty Utilities anticipates that the distribution planning criteria will, in general, be applied to both Liberty and New England Power assets serving Liberty customers, however all 115kV transformers serving Liberty customers are owned and maintained by National Grid. System Non-Wires and Wires solution alternatives will be developed along the lines of these criteria recognizing, however, the unique nature of transmission supply contingencies on the distribution system.

3.2 Sub-Transmission System

The sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are considered neither bulk transmission nor distribution. The voltages for Liberty's sub transmission system include 23 and 13.8 kV. The voltages for National Grid sub transmission system include 46 kV. The sub-transmission system is designed in an open loop or "radial" system and generally provides a redundant supply for distribution substations. The sub-transmission system is presently designed with conductors ranging from 336.4 ACSR to 1113 thousand circular mils ("kcmil") overhead conductors and from 500 to parallel 1000 kcmil copper underground conductor. There are eight sub-transmission lines that are maintained by Liberty Utilities.

3.3 Distribution Feeders

The distribution feeders from each substation are in a "radial" configuration with provisions for manual or automatic transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductors. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline and fuses and trip savers on the branch circuits. The Liberty Utilities distribution system is comprised of approximately 41 feeders ranging from 2.4kV to 13.2kV.

4.0 EQUIPMENT RATINGS

Thermal limits are recognized for all system elements in conducting planning studies. Current in equipment and lines are limited so that voltage drops are held to reasonable values; so that conductors will not be severely annealed or damaged; so that switches, connectors, etc. will not be overloaded and that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures, 2) load cycles, 3) wind velocities, and 4) potential loss of life of equipment.

Liberty's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

4.1 Overhead Conductors

The current carrying capacity (also known as, "ampacity") of an overhead conductor may be limited either by conductor clearances or maximum allowable operating temperature under a predefined set of reasonably severe summer or winter ambient conditions. The Company's Overhead Construction Standards book lists maximum ratings not to be exceeded for each conductor for normal and emergency operation.

As part of system operation, standard conductor sizes for overhead distribution construction of #2 AAAC, 1/0 AAAC and 477 AAAC or equivalent tree wire have been selected by Liberty Utilities.

The following general guidelines were developed for 13.2 kV overhead distribution lines:

- New single-phase overhead distribution lines should be constructed with #1/0 AAAC and new single-phase underground distribution lines should be constructed with #1/0 AL for loads less than 500kW.
- The single-phase lines should be reconductored to three-phase wherever needed based on operating conditions, phase imbalance and voltage drop.
- New three-phase overhead distribution lines and/or future distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:
    - For loads less than 3,000 kW: 1/0 AAAC
    - For loads greater than 3,000 kW: 477 AAAC
- The single-phase and three phase lines should be reconductored with covered tree conductor or spacer cable wherever needed based on operating conditions in tree prone areas.

The maximum ampacity of an overhead conductor is estimated for Normal (continuous) and Long-Time Emergency (LTE) operations for summer and winter conditions.

4.1.1 Normal Capability

The Normal rating shall be interpreted as the maximum value for normal peak loads on all new and rebuilt feeders. This is done to accommodate emergency conditions where ampacity may be increased for a period of time no greater than 24 hours. The temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, and covered conductors.

4.1.2 Long-Time Emergency Capabilities (24 hours)

The LTE rating shall be interpreted as the absolute maximum ampacity allowed for a given conductor. This ampacity should not be exceeded at any time unless an appropriate engineering review has been conducted. The temperature limit for LTE for 100% ampacity for operating conductor at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, and covered conductors.

4.1.3 Short-Time Emergency Capability (As needed)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are typically less than 15 minutes in duration.

4.2 Underground Cables

Underground distribution line ratings were derived from the October 1957 AIEE paper entitled "The Calculation of the Temperature Rise and Load Capability of Cable System" by J.H. Neher and M.H. McGrath. These calculations integrate all aspects of the cable system design such as conductor material, conductor size, insulation, properties, insulation thickness, cable type, shield connections, load characteristics, installation conditions and environment. Cable ampacities are based on normal and emergency operating conditions. Normal cable ampacities are based on a 90° insulation operating temperature while emergency cable ampacities are based on 130° insulation operating temperature. The Company's underground construction standards book provides estimates of cable ampacity for common sizes and configuration of main line cables. Given the many different aspects of a cable system, specific cable ratings are typically derived using computer software such as Synergee Electric or PC Amp.

New three-phase underground distribution lines or future three-phase underground distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:

- For loads less than 1000 kW: #1/0 AL
- For loads greater than 1000 kW: 500 MCM CU
- For feeder cable getaways: 1000 MCM CU

Ampacities are defined for underground cables as follows:

4.2.1 Normal Ampacity (Continuous)

This is the maximum loading on the cable that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle.

4.2.2 100-300 Hour Ampacity (LTE)

This is the maximum emergency loading on the cable that does not cause the conductor temperature to exceed its applicable emergency value over a period of several consecutive 24-hour load cycles. At the end of the emergency time period, the load on the cable must be reduced to a value within its normal ampacity.

4.2.3 One-Hour to 24-Hour Emergency Ampacities (STE)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are the maximum emergency loadings on the cable that do not cause the conductor temperature to exceed its allowable emergency value at any time during the period. At the end of the emergency time period, the load on the cable must be reduced so that the peak load in the next load cycle does not exceed the LTE ampacity (defined above).

4.3 Transformers

Distribution substation transformers are rated for loading according to the American National Standards Institute ("ANSI") standards for maximum internal hot spot and top oil temperatures. This is detailed in the Institute of Electrical and Electronics Engineers ("IEEE") Guide for Loading Mineral-Oil-Immersed Power Transformers up to and including 100 MVA with 55°C, or 65°C, winding temperature rise (ANSI/IEEE C57.91 latest version). The manufacturer's factory test data and the experienced 24-hour loading curve data are used in an iterative computer program that calculates allowable loading levels.

The transformer's "ratings" for the Normal ("N"), Long Term Emergency ("LTE"), and Short Term Emergency ("STE") load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer's life caused by its operation at the criteria temperatures for a specified duration, and on a defined load curve. Three categories of transformer capabilities are defined below:

4.3.1 Normal Capability

Winter normal and summer normal capabilities are based on a normal daily load cycle and on the maximum 24-hour average ambient temperature for the period involved. The maximum load for Normal operation of the transformer is determined and set when the operation of the transformer at that level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or the Top Oil Temperature exceeds 110 °C, or the Hot Spot Copper temperature exceeds 180 °C. Conditions above any of these limitations will result in a shortening of the transformer service life beyond prescribed design levels and/or physical damage to the equipment.

4.3.2 Long-Time Emergency Capabilities (1 hour to 300 hours)

These capabilities are based on a normal daily load cycle, with the emergency load increment added. The maximum 24-hour average ambient temperature is used for the appropriate season. The LTE rating of a substation transformer is determined and set when the 24 hour operation of the transformer, with that additional load in each of the hours in the 24 hour load cycle curve, causes a cumulative (24 hour) 3.0% loss of transformer life or the Top Oil temperature to exceed 130 °C, or the hot spot copper temperature to exceed 180 °C.

4.3.3 Short-Time Emergency Capability (15 minutes or less)

The STE rating of a transformer is determined and set when the one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (i.e., 24 hour) 3.0% Loss of

Transformer Life or a hot spot copper temperature exceeding 180°C. However, the maximum STE rating is limited to a value equal to twice the transformer's "nameplate" rating (i.e., 200%).

4.4 Other Equipment

In addition to the items above, normal and emergency capabilities are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers. Emergency capabilities usually involve elevated temperatures with some potential loss of equipment life. However, any circuit rating may be limited by other circuit equipment such as circuit breakers, disconnects, regulators, et cetera. These ratings are generally based on the allowable maximum temperature of the equipment. The facility (feeder, sub transmission line, and/or transformer) rating is determined by identifying the "limiting device" and applying the rating criteria for that device or equipment.

4.4.1 **Distribution Overhead Transformers**

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
145%	180%	160%	200%

4.4.2 **Distribution Single Phase Padmount Transformers**

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
140%	160%	140%	160%

4.4.3 **Distribution Three Phase Padmount**

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
110%	110%	110%	110%

4.4.4 **Distribution Step-Down Transformers**

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
110%	110%	110%	110%

4.4.5 **Circuit Breakers**

The following generic ratings in % of nameplate are used: NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
107%	123%	115%	130%

4.4.6 **Voltage Regulators**

The following generic regulator ratings in % of nameplate for 10% regulation are used:

55ºC INSULATION SYSTEM				**65ºC INSULATION SYSTEM**			
NORMAL		EMERGENCY		NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
125%	148%	125%	148%	141%	160%	141%	160%

4.4.7 **Disconnect Switches**

The following generic air switches ratings in % of nameplate:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
113%	134%	139%	147%

4.5 Equipment Rating Criteria Summary

The major equipment ratings to be used by planning engineers relate to transformers, overhead lines and underground cables. The normal and LTE rating limits for feeders, sub transmission lines and transformers may be applied for the time associated with each rating. Table 4 summarizes the durations for emergency loading that system operators must be aware of including the limiting factor involved in any contingency. There is also a short time emergency (STE) rating that is mainly used for transformers and must not exceed

200% of nameplate rating. Table 5 summarizes the Equipment Rating criteria, as described in more detail above.

Table 4. Facility Rating Durations

Equipment	Normal	LTE	STE
Feeders	Continuous	24 Hours	As Needed
Sub Transmission lines	Continuous	24 Hours	As Needed
Transformer	Continuous	1 - 300 Hours	15 Minutes

Table 5. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	Duration	Design Criteria	Duration	Design Criteria	Duration	Design Criteria
Normal	Continuous	• The maximum value for normal peak loads on all new and rebuilt feeders • Temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, & covered conductors	Continuous	• Maximum loading that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle • Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	• Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or • The Top Oil Temperature exceeds 110 °C, or • The Hot Spot Copper temperature exceeds 180 °C
LTE	24 Hours	• The absolute maximum ampacity allowed for a given conductor and should not be exceeded at any time. • Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, & covered conductors	100 - 300 Hours	• Maximum loading that does not cause the conductor temperature to exceed its design value over several consecutive 24-hour load cycles. • Emergency cable ampacities are based on 130° insulation operating temperature.	1 - 300 Hours	• Level for the peak hour with the emergency load added in the 24-hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer life, or • the Top Oil Temperature exceeds 130 °C, or • the Hot Spot Copper temperature exceeds 180 °C
STE	As Needed	• Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	• Maximum loading that does not cause the conductor temperature to exceed its allowable emergency value at any time during a 24-hour load cycle. • Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	• The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer Life, or • a hot spot copper temperature exceeding 180°C. • Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

5.0 DISTRIBUTION SUBSTATION TRANSFORMER LOADING CRITERIA

The ratings of transformers are calculated from their thermal heat transfer characteristics and the expected electric loading experience over a 24-hour cycle. All distribution substation transformer bank ratings are evaluated seasonally for their summer and winter values.

5.1 Normal Operation Design Criteria

Normal operation is the condition under which all-electric infrastructure equipment is fully functional. A substation transformer will not be loaded above 75% of its Normal rating during non-contingency operating periods.

5.2 First Contingency Emergency Design Criteria

First contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. For first contingency emergency conditions involving the loss of one distribution substation transformer in an existing two-bank or more configuration, the following system design criteria applies:

- In cases where a first contingency situation causes the LTE rating of the remaining transformer to be exceeded, all load above the LTE rating of the remaining transformers must be transferred to neighboring facilities or shed 15 minutes without exceeding the LTE rating of the substation transformers or distribution circuits receiving the load.
- In cases where a first contingency situation will cause the STE rating of a remaining transformer to be exceeded, load must be immediately reduced (dropped/shed) to a level within the STE. All load between the LTE and STE ratings, and any load that was initially shed to get the remaining transformer below its STE rating, must be transferred to peripheral facilities without exceeding the LTE rating of the substation transformers or the distribution circuits receiving the load.
- Repairs or the installation of mobile equipment are expected to require at least a 24 hour implementation.
- For a typical Liberty owned substation consisting of 9.375 MVA transformers, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5 MW. If more than 60MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts and the cost to mitigate.

5.3 Automatic Transfer of Load

Locations with two or more transformers at a substation utilize automatic bus transfers. Based on the loading limitations on Section 5.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during a first contingency. Cases where automatic restoration is disabled will be communicated with Electric Control as part of an annual summer preparedness review. Disabling of automatic bus transfer schemes will not be considered as a permanent solution to a criteria violation.

6.0 DISTRIBUTION CIRCUIT LOADING CRITERIA

6.1 Normal Operation Design Criteria

A feeder circuit should be loaded to no more than 75% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions and/or provides capacity to serve new business or commercial applications in a timely manner.

After 75% loading is reached, unacceptable voltage levels are often experienced on tap lines and at the end of the feeder.

6.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a distribution circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. For the loss of a distribution feeder, the following criterion applies:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies. In general, and whenever practical, each feeder should have three feeder ties to neighboring feeders.
- Distribution feeders should be limited to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or 2,000kVA of load between disconnecting devices.
- After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. All adjoining tie feeders can be loaded to their maximum LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- If more than 16 MWh of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- For a typical Liberty owned 10 MW feeder, approximately 8 MW would need to be restored via switching within one hour. The remaining 2 MW would be restored after

repairs within 4 hours. Where longer repair times are needed such as for a cable getaway fault, the load out of service should be reduced to 1 MW.

6.3 Automatic transfer on feeders

In some cases it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers or due to automatic reclosing loop schemes in the distribution lines.

6.4 Primary Circuit Voltage Criteria

The normal and emergency voltage to all customers shall be in line with limits specified by the state of NH and within the limits of ANSI C84.1-2006.

These upper and lower voltage ANSI limits, as measured at the customer's meter, are listed below in Table 6:

Table 6. Voltage Requirements for LU

For 120 V – 600 V Systems				
Nominal Voltage (V)	Service Voltage (V)			
	Range A		Range B	
	Max	Min	Max	Min
120	126	114	127	110
240	252	228	254	220
480	504	456	508	440

Source: ANSI

Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or pad mounted line regulators.

Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 7 above are maintained. The ultimate goal is to keep all customers' service voltages within accepted limits. From a supply point of view, the acceptability of voltage regulation is determined at the distribution substation buses. At substations with feeder or bus regulating equipment, the regulation (the extreme range of voltages expressed as a percentage of normal peak load voltage) should be no greater than 10 percent for normal and 15 percent for emergency conditions on the source side of the regulating equipment. Most

I. PURPOSE

To establish a procedure for calculating the seasonal **Peak Load Forecast** for each of the **loadflow** areas and the PSNH system.

II. AREAS/PERSONS AFFECTED

This procedure applies to or affects:

- PSNH System Planning and Strategy

III. POLICY

It is the policy of PSNH to develop a peak load forecast each year after the summer and winter annual **Peak Load** is achieved. It is intended that this procedure be followed to provide a consistent practice of developing a **Peak Load Forecast** using historical data, known **block load** changes and engineering judgment.

IV. DEFINITIONS

A. **Adjusted Growth Rate (AGR) –** The Compound Growth Rate (CGR) adjusted with input from Field Engineering.

B. **Area Peak Load Tables -** Excel spreadsheets containing historical area **Peak Loads** and Summer and Winter **Peak Load Forecasts** for the next ten years.

C. **Block Loads** – Load changes which may add to or subtract from the forecasted load level for the study area. Additive **Block Loads** are known large industrial customers, blocks of commercial growth, and support of **Rate B customers**. Subtractive **Block Loads** include industrial customer closings.

D. **Compound Growth Rate (CGR)** – The calculation of the peak load growth rate, on average, over a 10 year period based on historical peaks.

E. **Degree Days** - A degree day compares the outdoor mean daily temperature to a standard of 65 degrees Fahrenheit (F).

F. **ESCC** – Electric System Control Center.

G. **Heat wave** – Multiple contiguous days during the summer with cooling **Degree Days** of 17 or higher.

H. **Load Forecast Folder** – K drive folder set up for each study done. This is located at “K:\Deptdata\Energy Delivery\System Plan&Strategy\Load Forecasts” and designated with the year of the forecast calculation.

I. **Loadflow** – The PSS/E computer model of the PSNH electric distribution system.

J. **Loadflow Area** – The 12 different geographical areas modeled in the **Loadflow**.

K. **Peak Load Forecast** – The highest hourly summer and winter load level that is projected to occur in future years.

L. **Peak Load** – The annual highest historical hourly load level achieved during the previous years for summer and winter.

M. **Projected Growth Rate (PGR)** – The annual growth rate that is projected to occur in the future years.

N. **PSNH System** – PSNH defined zones in the **Loadflow**. The **Loadflow** defines the 34.5kV and below system as zones 2 – 8 and 10 - 12. (Zones 9 & 13 are Unitil.)

O. **PI System** – Database of historical operating data which connects the user to the **ESCC** historical load database using Microsoft Excel. This is used for gathering data on distribution loads including 34.5 kV transformers and lines.

P. **Rate B Customer** – A customer with generation that offsets its own load but requires PSNH to have the capability of serving its entire load when generation is out of service.

V. SAFETY MANUAL

No	Should a copy of this procedure be inserted into the functional area's safety and health handbook?

VI. OVERVIEW

The intent of this procedure is to define the steps required to develop 10 year summer and winter **Peak Load Forecasts.**

This process is used to calculate a peak load forecast for each of PSNH's geographical **Loadflow Areas** and the **PSNH System**. Unitil provides forecast information for its **Loadflow Areas** and is included in the **Peak Load Forecast**.

VII. PERIODIC REVIEW OF GUIDELINE

The Procedure Owner is responsible for maintaining this guideline and keeping current with good engineering design practices. The Procedure Owner for this Energy Delivery Procedure is the Manager of System Planning and Strategy.

Annually, the Procedure Owner shall review the design guideline for conformance to standard engineering practices and industry criteria to determine if the guideline shall be revised, rewritten, or cancelled.

As required, the Procedure Owner shall recommend changes to the Director of Energy Delivery. If approved by the Director, the Procedure Owner shall change the Procedure in accordance with AP-2001 Writing and Publishing Procedures.

VIII. PROCEDURE

A. Identify Current Year Area Peaks

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Copy last year's folder and update the name to include the new year. This folder is located in "K:\Deptdata\Energy Delivery\System Plan&Strategy\Load Forecast\". The naming format is 'YYYY Summer Forecast', for the summer forecast and 'YYYY-YY Winter Forecast', for the winter. (The new folder is the folder you will be working with for the rest of this procedure).
System Planning & Strategy	2.	Open "Current Summer System Loading.xls" Shown in (APPENDIX A) for summer loading and "Current Winter System Loading.xls" for winter loading.
System Planning & Strategy	3.	On this loading spreadsheet, update the start and end dates for each month. Only the year should be changed. Note: after the date has been updated 'F9' must be pressed to update the data. (This will download monthly peak load data from PI, for each area)
System Planning & Strategy	4.	Verify the daily data to make sure it corresponds with the rest of the days in the month. (Invalid data can be received; change the invalid data font to red and ignore these values). If you question the value verify it with the ESCC and/or the Circuit Owner.
System Planning & Strategy	5.	Identify the peak load for each area by updating the formula in the 'Monthly Maximum' row to exclude invalid data (Appendix A).
System Planning & Strategy	6.	Verify the configuration of each area at the time of the area's peak with the ESCC and/or the Circuit Owner.
System Planning & Strategy	7.	Adjust the area peak load if necessary by adding or subtracting load that was switched to another area at the time of peak.

System Planning & Strategy	8.	Identify the season's maximum for each area. Winter months are: December, January, February, and March. Summer months are June, July, and August.
System Planning & Strategy	9.	If the **AREA** peak for the current year is a new historical system peak, then this is used to develop the new **Loadflow Area** and **PSNH System** forecasts. Skip Step 10 and continue to Section B.
System Planning & Strategy	10.	If the current year's peak is not a new historical peak, then the 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.

EXCEPTIONS

a. If the 5 year historical peak is prior to the last year with consecutive days of 17 cooling degree days, use the last year with consecutive days of 17 cooling degree days as the 5 year historical peak year.
b. If the 5 year historical peak is after the last year with consecutive days of 17 cooling degree days, use the data from the year that yields the larger forecasted value.

B. Update PSNH System Current Year Loads

RESPONSIBILITY		ACTION
Marketing Support	1.	The Load Research Group in the Marketing Support Department calculates the load in MWH at the time, hour, and day of the current year's peak at "PSNH Delivered Peak Load" report.
System Planning & Strategy	2.	Open the previous years forecast "YYYY-YY Winter Forecast.xls" for winter and "YYYY Summer Forecast.xls" for summer. Save the file using the current year in the 'Y' locations. Notice there are multiple tabs. Press the tab to bring up the sheet titled "Peak_Loads". (Appendix B).

System Planning & Strategy	3.	Insert a line underneath the last year's data and follow the format of the previous year, inputting each area's new peak, calculated in Sections A. (Appendix C).
System Planning & Strategy	4.	From the Marketing Support Department's "PSNH Delivered Peak Load Report", insert the value "PSNH Peak Load Including NHEC, Ashland, New Hampton and Wolfeboro Wholesale Loads Excludes AES OFFLINE SS Excludes CVEC Load" in the **Area Peak Load Table** in the current year PSNH **Peak Load** cell.
System Planning & Strategy	5.	If the year had multiple consecutive 17 cooling **Degree Days**, shade the rows light gray as done in previous years. Cooling **Degree Day** information is located at 'K:\Deptdata\Energy Delivery\System Plan&Strategy\Load ForecastsCDD_ALLYEARS.xls'

C. Incorporate Unitil System Forecast

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Include in **Area Peak Load Tables** the peak load forecast for UES/Capital and UES/Seacoast areas provided by UES. **UES/Capital** – The Unitil Electric region that serves the Concord area. **UES/Seacoast** – The Unitil Electric region on the Seacoast including Hampton, Exeter, Seabrook, Kingston, etc.

D. Update PSNH Area Peak Load Forecasts

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Calculate the percent difference (% Difference). This can be done by copying and pasting the formula in the above cell. (Appendix D). The formula is: $\left(\frac{CurrentYear}{PreviousYear}\right)-1$

System Planning & Strategy	2.	Calculate the Compound Growth Rate (CGR). (Appendix E). The formula is: $$CGR = \left[\left(\frac{5YearHistorPk}{10YrOldPk} \right)^{\frac{1}{x}} - 1 \right]$$ X=PkYr-10YrPkYr Note: If the 10 year old peak is a low point compared to the surrounding peaks, adjust the 10 year 'look back time' to 11 years based on the higher peak and then update formula. (Appendix F).
System Planning & Engineering	3.	Update the Adjusted Growth Rate (AGR). This is done based on the Compound Growth Rate (CGR) and with input from circuit owners and Division Field Engineering Managers.
System Planning & Strategy	4.	Update the Projected Growth Rate (PGR). This is done based on rounding the CGR up to the next 0.25%. (Note: Minimum PGR is 0.5%.)
System Planning & Strategy	5.	Update the next year's peak. (Appendix G). The following equation: $NxtYrPk = (5YearHistorPk)(1 + AGR)^{NxtYr - 5YearHistorPkYr}$ EXCEPTIONS a. If the 5 year historical peak is prior to the last year with consecutive days of 17 cooling degree days, use the last year with consecutive days of 17 cooling degree days as the 5 year historical peak year. b. If the 5 year historical peak is after the last year with consecutive days of 17 cooling degree days, use the data from the year that yields the larger forecasted value.

System Planning & Strategy	7.	Update the forecast for the next 10 years. Adjust the first forecasted year in Column A to reflect the next year (Appendix C), all other years will automatically update. Calculate future peaks for years 2 – 5 (Appendix G) using the equation below: $$FuturePks(2-5) = (PreviousYrPk)(1 + AGR)$$ Calculate the future peaks for years 6-10 using the following equation: $$FuturePks(6-10) = (PreviousYrPk)(1 + PGR)$$
System Planning & Strategy	8.	Repeat sections D.1-D.7 for all Loadflow Areas & PSNH System.

E. Area Peak Load Graph Adjustment

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Update **AREA** by clicking on its tab. Notice each **AREA** has its own tab at the bottom of the **Area Peak Load Tables**.
System Planning & Engineering	2.	Enter the areas seasonal peak in its sheet. Add any new rows and copy the formulas from any existing rows into the new rows to maintain a 10 year projection. (Appendix H).
System Planning & Strategy	3.	Adjust the Low and High Annual Growth rates and analyze the sensitivity of the previously determined Projected Annual Growth Rate.
System Planning & Strategy	4.	Change the “Adjustable” percentage to ensure that the **PGR** accurately follows the envelope. If a better match is found update the **PGR**.

F. Finalize Peak Load Forecast

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Add and adjust spreadsheet notes to include pertinent information for the **Peak Load Forecast.**
System Planning & Strategy	2.	Save **Peak Load Forecast** in the **Load Forecast Folder**. Change spreadsheet properties to be a read-only file.
System Planning & Strategy	3.	Revise throughout the year as required, saving each update as a Revision.

IX ED-3029 REVISION HISTORY

Revision Number	Date	Reason
Rev 0	05/04/2007	Original issue
Rev 1	10/24/2007	Minor housekeeping Changes
Rev 2	05/06/2015	Complete Rework

X. APPENDICES

APPENDIX A
ACQUIRE PEAK LOAD INFORMATION

APPENDIX B
FORECAST SPREADSHEET OVERVIEW

APPENDIX C
RECORD PEAK LOAD INFORMATION

APPENDIX D
CALCULATE PERCENT DIFFERENCE

APPENDIX E
CALCULATE NEW COMPOUND GROWTH RATE (10 YEAR)

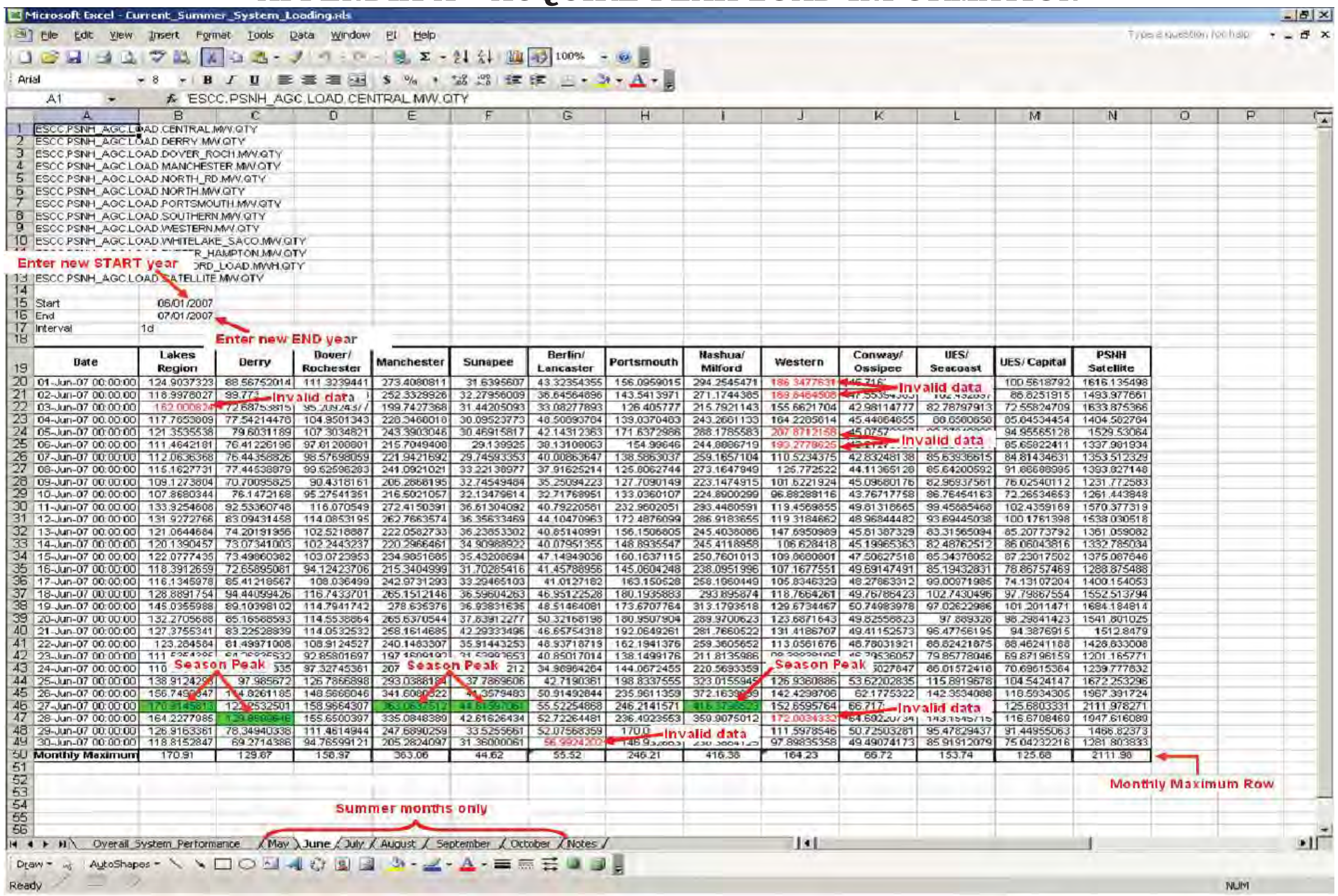
APPENDIX F
CALCULATE NEW COMPOUND GROWTH RATE (OTHER THAN 10 YEARS)

APPENDIX G
CALCULATE PROJECTED GROWTH

APPENDIX H

UPDATE AREA CHARTS AND GRAPHS

APPENDIX A – ACQUIRE PEAK LOAD INFORMATION



Microsoft Excel - Current_Summer_System_Loading.xls

A1: 'ESCC.PSNH_AGC.LOAD.CENTRAL.MW.QTY

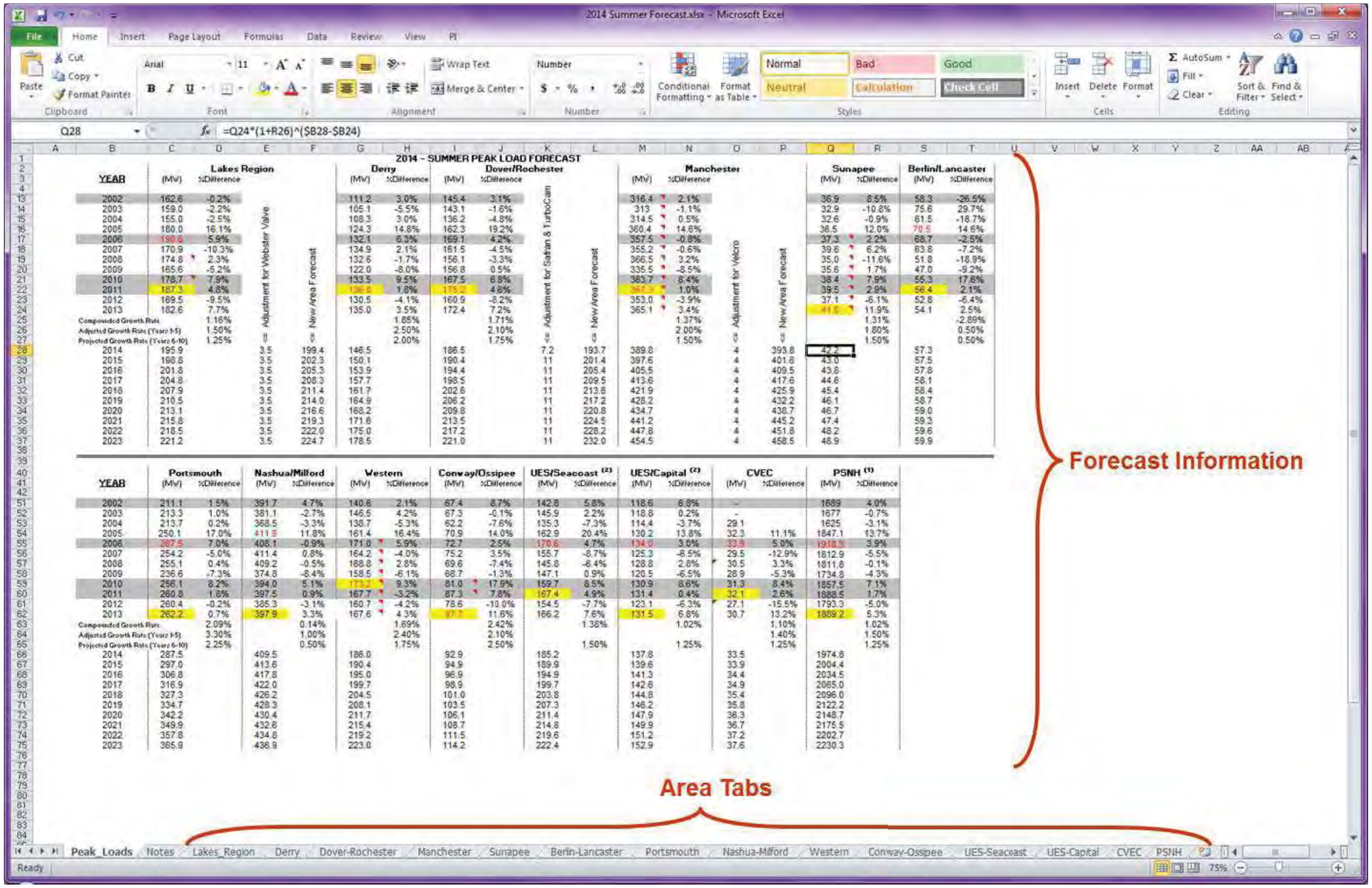
1 ESCC.PSNH_AGC.LOAD.CENTRAL.MW.QTY
2 ESCC.PSNH_AGC.LOAD.DERRY.MW.QTY
3 ESCC.PSNH_AGC.LOAD.DOVER_ROCH.MW.QTY
4 ESCC.PSNH_AGC.LOAD.MANCHESTER.MW.QTY
5 ESCC.PSNH_AGC.LOAD.NORTH_RD.MW.QTY
6 ESCC.PSNH_AGC.LOAD.NORTH.MW.QTY
7 ESCC.PSNH_AGC.LOAD.PORTSMOUTH.MW.QTY
8 ESCC.PSNH_AGC.LOAD.SOUTHERN.MW.QTY
9 ESCC.PSNH_AGC.LOAD.WESTERN.MW.QTY
10 ESCC.PSNH_AGC.LOAD.WHITELAKE_SACO.MW.QTY
11 ...R_HAMPTON.MW.QTY
12 ...ORD_LOAD.MWH.QTY
13 ESCC.PSNH_AGC.LOAD.SATELLITE.MW.QTY

15 Start 06/01/2007
16 End 07/01/2007
17 Interval 1d

Date	Lakes Region	Derry	Dover/ Rochester	Manchester	Sunapee	Berlin/ Lancaster	Portsmouth	Nashua/ Milford	Western	Conway/ Ossipee	UES/ Seacoast	UES/ Capital	PSNH Satellite
01-Jun-07 00:00:00	124.9037323	88.56752014	111.3239441	273.4080811	31.6395607	43.32354355	156.0959015	294.2545471	186.3477631	[illegible]	[illegible]	100.5618792	1616.135498
02-Jun-07 00:00:00	116.9978027	[illegible]	[illegible]	252.3329926	32.27956009	36.64564696	143.5413971	271.1744385	169.8464508	[illegible]	[illegible]	86.8251915	1493.977661
03-Jun-07 00:00:00	162.000824	72.68753815	[illegible]	199.7427368	31.44205093	33.08277893	126.405777	215.7921143	155.6621704	42.98114777	82.78797913	72.55824709	1633.875366
04-Jun-07 00:00:00	117.7653809	77.54214478	104.9501343	228.3466018	30.09523773	46.50690764	139.0370483	243.2661133	164.2265614	45.44664655	88.6580656	85.84534454	1404.582764
05-Jun-07 00:00:00	121.3535538	79.6031189	107.3034821	243.3903046	30.46915817	42.14312363	171.6372986	288.1785583	207.8712158	[illegible]	[illegible]	94.95565128	1529.53064
06-Jun-07 00:00:00	111.4642181	76.41226196	97.61200801	215.7049408	29.139925	38.13108063	154.99646	244.8886719	193.2778625	[illegible]	[illegible]	85.65822411	1337.981934
07-Jun-07 00:00:00	112.0636368	76.44358826	98.57698059	221.9421692	29.74593353	40.00863647	138.5863037	259.1657104	110.5234375	42.83248138	85.63936615	84.81434631	1353.512329
08-Jun-07 00:00:00	115.1627731	77.44538879	99.62596283	241.0921021	33.22138977	37.91625214	125.8062744	273.1647949	126.772522	44.11365128	85.64200592	91.86688995	1393.827148
09-Jun-07 00:00:00	109.1273804	70.70095825	90.4316161	205.2668195	32.74549484	35.25094223	127.7090149	223.1474915	101.6221924	45.09680176	82.96937561	76.02540112	1231.772583
10-Jun-07 00:00:00	107.8680344	76.1472168	95.27541351	216.5021057	32.13479614	32.71768951	133.0360107	224.8900299	96.88288116	43.76717758	86.76454163	72.26534653	1261.443848
11-Jun-07 00:00:00	133.9254608	92.53360748	116.070549	272.4150391	36.61304092	40.79220581	232.9602051	293.4480591	119.4569855	49.81318665	99.45685468	102.4359169	1570.377319
12-Jun-07 00:00:00	131.9272766	83.09431458	114.0853195	262.7663574	36.35633469	44.10470963	172.4876099	286.9183655	119.3184662	48.96844482	93.69445038	100.1761398	1538.030518
13-Jun-07 00:00:00	121.0644684	74.20191956	102.5218887	222.0582733	36.23653302	40.65140991	156.1506805	245.4038086	147.6950989	45.81387329	83.31565094	85.20773792	1361.059082
14-Jun-07 00:00:00	120.1390457	73.07341003	102.2443237	220.2966461	34.90988922	40.07951355	148.8935547	245.4118958	106.628418	45.19965363	82.48762512	86.06043816	1332.785034
15-Jun-07 00:00:00	122.0777435	73.49860382	103.0723953	234.9851685	35.43208694	47.14949036	160.1637115	250.7601013	109.8680801	47.50627518	85.34378052	87.23017502	1375.087646
16-Jun-07 00:00:00	118.3912659	72.65895081	94.12423706	215.3404999	31.70285416	41.45788956	145.0604248	238.0951996	107.1677551	49.69147491	85.19432831	78.86757469	1288.875488
17-Jun-07 00:00:00	116.1345978	85.41218567	108.036499	242.9731293	33.29465103	41.0127182	163.150528	258.1960449	105.8346329	48.27863312	99.00971985	74.13107204	1400.154053
18-Jun-07 00:00:00	128.8891754	94.44099426	116.7433701	265.1512146	36.59604263	46.95122528	180.1935883	293.895874	118.7664261	49.76786423	102.7430496	97.79867554	1552.513794
19-Jun-07 00:00:00	145.0355988	89.10398102	114.7941742	278.635376	36.93831635	48.51464081	173.6707764	313.1793518	129.6734467	50.74983978	97.02622986	101.2011471	1684.184814
20-Jun-07 00:00:00	132.2705688	85.16568593	114.5538864	265.6370544	37.63912277	50.32168198	180.9507904	289.9700623	123.6871643	49.82558823	97.889328	98.29841423	1541.801025
21-Jun-07 00:00:00	127.3755341	83.22528839	114.0532532	258.1614685	42.29333496	46.65754318	192.0649261	281.7660522	131.4186707	49.41152573	96.47756195	94.3876915	1512.8479
22-Jun-07 00:00:00	123.284584	81.49971008	108.9124527	240.1463307	35.91443253	48.93718719	162.1941376	259.3605652	113.0561676	46.78031921	88.82421875	88.46241188	1428.833008
23-Jun-07 00:00:00	[illegible]	[illegible]	92.85801697	[illegible]	[illegible]	40.85017014	138.1499176	211.8135986	[illegible]	[illegible]	79.85778046	69.87196159	1201.165771
24-Jun-07 00:00:00	[illegible]	[illegible]	97.32745361	[illegible]	[illegible]	34.98964264	144.0672455	220.5693359	[illegible]	[illegible]	86.01572418	70.69615364	1239.777832
25-Jun-07 00:00:00	[illegible]	97.985672	126.7866898	[illegible]	37.7869606	42.7190361	198.8337555	323.0155945	126.9360886	53.62202835	115.8919678	104.5424147	1672.253296
26-Jun-07 00:00:00	[illegible]	[illegible]	148.5666046	[illegible]	[illegible]	50.91492844	235.9611359	[illegible]	142.4298706	62.1775322	142.3534088	118.5934305	1967.391724
27-Jun-07 00:00:00	[illegible]	[illegible]	158.9664307	[illegible]	[illegible]	55.52254868	246.2141571	[illegible]	152.6595764	[illegible]	[illegible]	125.6803331	2111.978271
28-Jun-07 00:00:00	164.2277985	[illegible]	155.6500397	335.0848389	42.61626434	52.72264481	236.4923553	359.9075012	172.0034332	[illegible]	[illegible]	116.6708469	1947.616089
29-Jun-07 00:00:00	126.9163361	78.34940336	111.4614944	247.6890259	33.5255661	52.07568359	[illegible]	[illegible]	111.5978546	50.72503281	95.47829437	91.44955063	1466.82373
30-Jun-07 00:00:00	118.8152847	69.2714386	94.76599121	205.2824097	31.36000061	56.9924202	[illegible]	[illegible]	97.89835358	49.49074173	85.91912079	75.04232216	1281.803833
Monthly Maximum	170.91	129.67	158.97	363.06	44.62	55.52	246.21	416.38	164.23	66.72	153.74	125.68	2111.98

Overall_System_Performance / May / June / July / August / September / October / Notes

APPENDIX B – FORECAST SPREADSHEET OVERVIEW



APPENDIX C – RECORD PEAK LOAD INFORMATION

2008 - SUMMER PEAK LOAD FORECAST (rev.1 - 5/15/08)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
4		Lakes Region		Derry		Dover/Rochester		Manchester		Sunapee		Berlin/Lancaster		Portsmouth	
5	YEAR	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference
7	1994	114.8		54.5		116.3		237.7		30.7		69.2		138.5	
8	1995	126.6	10.3%	60.9	11.7%	116.1	-0.2%	244.6	2.9%	33.2	8.1%	78.6	13.6%	149.3	7.8%
9	1996	126.8	0.2%	74.1	21.7%	112.0	-3.5%	223.3	-8.7%	30.5	-8.1%	71.4	-9.2%	157.8	5.7%
10	1997	131.2	3.5%	78.3	5.7%	116.1	3.7%	246.7	10.5%	31.9	4.6%	73.6	3.1%	155.6	-1.4%
11	1998	136.0	3.7%	84.3	7.7%	113.7	-2.1%	262.9	6.6%	31.5	-1.3%	73.9	0.4%	166.5	7.0%
12	1999	143.2	5.3%	90.7	7.8%	118.7	4.4%	288.0	9.5%	26.7	-15.2%	81.4	10.1%	173.1	4.0%
13	2000	132.9	-7.2%	91.0	0.3%	119.5	0.7%	265.0	-8.0%	33.1	24.0%	85.7	5.3%	171.6	-0.9%
14	2001	163.0	22.6%	108.0	18.7%	141.0	18.0%	310.0	17.0%	34.0	2.7%	79.3	-7.5%	208.0	21.2%
15	2002	162.6	-0.2%	111.2	3.0%	145.4	3.1%	323.3	4.3%	36.9	8.5%	58.3	-26.5%	211.1	1.5%
16	2003	159.0	-2.2%	105.1	-5.5%	143.1	-1.6%	318.5	-1.5%	32.9	-10.8%	75.6	29.7%	213.3	1.0%
Added new line		5.0	-2.5%	108.3	3.0%	136.2	-4.8%	319.7	0.4%	32.6	-0.9%	61.5	-18.7%	213.7	0.2%
18	2005	180.0	16.1%	124.3	14.8%	162.3	19.2%	365.9	14.5%	36.5	12.0%	70.5	14.6%	250.1	17.0%
19	2006	190.6	5.9%	132.1	6.3%	169.1	4.2%	363.2	-0.7%	40.3	10.3%	68.7	-2.5%	267.5	7.0%
20	2007	170.9	-10.3%	134.9	2.1%	161.5	-4.5%	363.1	0.0%	42.6	5.8%	63.8	-7.2%	254.2	-5.0%
21	Compounded Growth Rate		4.16%		5.59%		3.48%		4.11%		2.93%		-1.08%		5.42%
22	Projected Growth Rate		4.00%		6.00%		3.00%		4.00%		3.50%		0.50%		5.50%
23	2008	203.0		148.6		170.5		407.3		46.6		83.9		300.0	
24	2009	211.1		157.6		175.6		423.6		48.2		84.3		316.5	
25	2010		Update year	167.0		180.9		440.5		49.9		84.7		333.9	
26	2011	228.4		177.0		186.3		458.1		51.6		85.1		352.3	
27	2012	237.5		187.7		191.9		476.5		53.4		85.6		371.7	
28	2013	247.0		198.9		197.7		495.5		55.3		86.0		392.1	
29	2014	256.9		210.8		203.6		515.3		57.3		86.4		413.7	
30	2015	267.1		223.5		209.7		535.9		59.3		86.8		436.4	
31	2016	277.8		236.9		216.0		557.4		61.3		87.3		460.4	
32	2017	288.9		251.1		222.5		579.7		63.5		87.7		485.7	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
36		Nashua/Milford		Western		Conway/Ossipee		UES/Seacoast		UES/Capital		CVEC		PSNH [1]	
37	YEAR	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference	(MW)	%Difference
39	1994	309.3		108.5		49.0		101.7		91.3				1291	
40	1995	307.2	-0.7%	109.0	0.5%	50.8	3.7%	106.2	4.4%	93.8	2.7%			1309	1.4%
41	1996	294.0	-4.3%	106.2	-2.6%	49.8	-2.0%	109.6	3.2%	95.8	2.1%			1266	-3.3%
42	1997	320.0	8.8%	117.7	10.8%	51.0	2.4%	111.6	1.8%	97.2	1.5%			1323	4.5%
43	1998	332.9	4.0%	125.8	6.9%	53.8	5.5%	115.2	3.2%	101.5	4.4%			1406	6.3%
44	1999	352.9	6.0%	128.9	2.5%	58.2	8.2%	118.8	3.1%	102.0	0.5%			1479	5.2%
45	2000	340.0	-3.7%	125.5	-2.7%	53.7	-7.7%	114.7	-3.5%	100.2	-1.8%			1447	-2.2%
46	2001	374.0	10.0%	137.7	9.7%	62.0	15.5%	135.0	17.7%	111.0	10.8%			1624	12.2%
47	2002	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%			1689	4.0%
48	2003	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%			1677	-0.7%
Added new line		8.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
50	2005	411.6	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
51	2006	408.1	-0.9%	168.0	4.1%	72.7	2.5%	164.32	0.9%	134.6	3.4%	33.9	5.0%	1918.3	3.9%
52	2007	411.4	0.8%	161.2	-4.1%	75.2	3.5%	155.30	-5.5%	126.1	-6.3%	29.5	-12.9%	1812.9	-5.5%
53	Compounded Growth Rate		2.64%		4.01%		3.96%		4.05%		3.34%		7.98%		3.54%
54	Projected Growth Rate		2.50%		3.70%		3.70%		4.00%		3.50%		3.50%		3.40%
55	2008	423.5		174.8		76.1		184.5		142.7		33.4		2021.7	
56	2009	434.1		181.3		78.9		191.1		146.3		34.5		2090.4	
57	2010		Update year	188.0		81.8		197.7		150.0		35.8		2161.5	
58	2011	456.0		194.9		84.8		204.3		153.6		37.0		2235.0	
59	2012	467.4		202.1		88.0		211.0		157.2		38.3		2310.9	
60	2013	479.1		209.6		91.2		217.7		160.9		39.6		2389.5	
61	2014	491.1		217.4		94.6		224.3		164.5		41.0		2470.8	
62	2015	503.4		225.4		98.1		231.0		168.2		42.5		2554.8	
63	2016	516.0		233.8		101.7		237.6		171.8		43.9		2641.6	
64	2017	526.9		242.4		105.5		244.3		175.5		45.5		2731.4	

APPENDIX D – CALCULATE PERCENT DIFFERENCE

2008 - SUMMER PEAK LOAD FORECAST [rev.1 - 5/15/08]

YEAR	Lakes Region (MW)	Lakes Region %Difference	Derry (MW)	Derry %Difference	Manchester (MW)	Manchester %Difference	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference	Portsmouth (MW)	Portsmouth %Difference
1994	114.8		54.5		[illegible]		30.7		69.2		138.5	
1995	126.6	10.3%	60.9	[illegible]	[illegible]	[illegible]	33.2	8.1%	78.6	13.6%	149.3	7.8%
1996	126.8	0.2%	74.1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	71.4	-9.2%	157.8	5.7%
1997	131.2	3.5%	78.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	73.6	3.1%	155.6	-1.4%
1998	136.0	3.7%	84.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	73.9	0.4%	166.5	7.0%
1999	143.2	5.3%	90.7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	81.4	10.1%	173.1	4.0%
2000	132.9	-7.2%	91.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	85.7	5.3%	171.6	-0.9%
2001	163.0	22.6%	108.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	79.3	-7.5%	208.0	21.2%
2002	162.6	-0.2%	111.2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	58.3	-26.5%	211.1	1.5%
2003	159.0	-2.2%	105.1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	75.6	29.7%	213.3	1.0%
2004	155.0	-2.5%	108.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	61.5	-18.7%	213.7	0.2%
2005	180.0	16.1%	124.3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	70.5	14.6%	250.1	17.0%
2006	190.6	5.9%	132.1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	68.7	-2.5%	267.5	7.0%
2007	170.9	-10.3%	134.9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	63.8	-7.2%	254.2	-5.0%
Compounded Growth Rate		4.16%		[illegible]		[illegible]		[illegible]		-1.08%		5.42%
Projected Growth Rate		4.00%		[illegible]		[illegible]				0.50%		5.50%
2008	203.0		148.6		[illegible]		[illegible]		83.9		300.0	
2009	211.1		157.6		[illegible]		[illegible]		84.3		316.5	
2010	219.6		167.0				49.9		84.7		333.9	
2011	228.4		177.0				51.6		85.1		352.3	
2012	237.5		187.7				53.4		85.6		371.7	
2013	247.0		198.9				55.3		86.0		392.1	
2014	256.9		210.8				57.3		86.4		413.7	
2015	267.1		223.5				59.3		86.8		436.4	
2016	277.8		236.9				61.3		87.3		460.4	
2017	288.9		251.1				63.5		87.7		485.7	

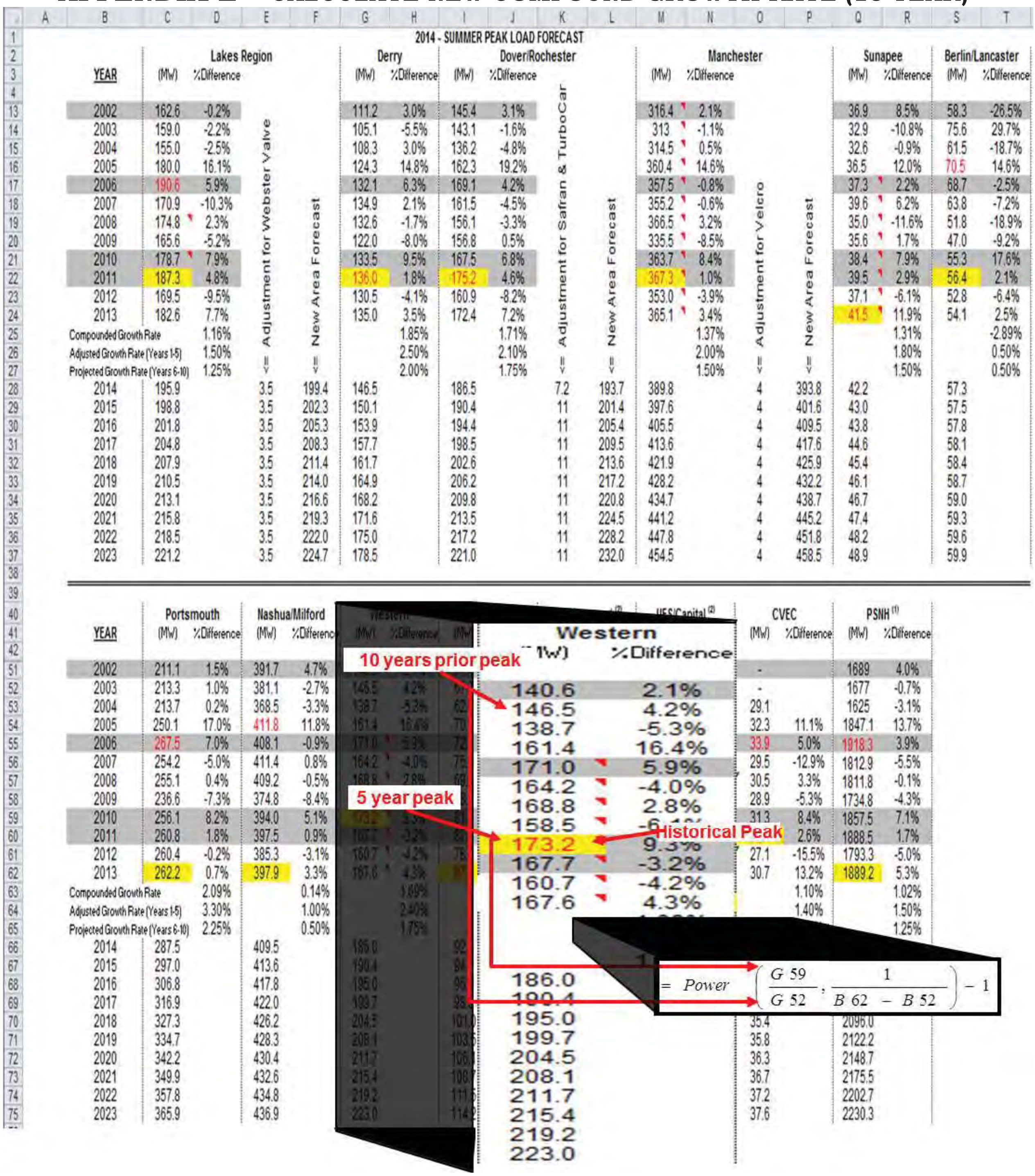
$= D8 / D7 - 1$

$= D9 / D8 - 1$

$= D20 / D19 - 1$

YEAR	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	Conway/Ossipee (MW)	Conway/Ossipee %Difference	UES/Seacoast (MW)	UES/Seacoast %Difference	UES/Capital (MW)	UES/Capital %Difference	CVEC (MW)	CVEC %Difference	PSNH [1] (MW)	PSNH [1] %Difference
1994	309.3		108.5		49.0		101.7		91.3				1291	
1995	307.2	-0.7%	109.0	0.5%	50.8	3.7%	106.2	4.4%	93.8	2.7%			1309	1.4%
1996	294.0	-4.3%	106.2	-2.6%	49.8	-2.0%	109.6	3.2%	95.8	2.1%			1266	-3.3%
1997	320.0	8.8%	117.7	10.8%	51.0	2.4%	111.6	1.8%	97.2	1.5%			1323	4.5%
1998	332.9	4.0%	125.8	6.9%	53.8	5.5%	115.2	3.2%	101.5	4.4%			1406	6.3%
1999	352.9	6.0%	128.9	2.5%	58.2	8.2%	118.8	3.1%	102.0	0.5%			1479	5.2%
2000	340.0	-3.7%	125.5	-2.7%	53.7	-7.7%	114.7	-3.5%	100.2	-1.8%			1447	-2.2%
2001	374.0	10.0%	137.7	9.7%	62.0	15.5%	135.0	17.7%	111.0	10.8%			1624	12.2%
2002	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%			1689	4.0%
2003	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%			1677	-0.7%
2004	368.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
2005	411.8	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
2006	408.1	-0.9%	168.0	4.1%	72.7	2.5%	164.32	0.9%	134.6	3.4%	33.9	5.0%	1918.3	3.9%
2007	411.4	0.8%	161.2	-4.1%	75.2	3.5%	155.30	-5.5%	126.1	-6.3%	29.5	-12.9%	1812.9	-5.5%
Compounded Growth Rate		2.64%		4.01%		3.96%		4.05%		3.34%		7.98%		3.54%
Projected Growth Rate		2.50%		3.70%		3.70%		4.00%		3.50%		3.50%		3.40%
2008	423.5		174.8		76.1		184.5		142.7		33.4		2021.7	
2009	434.1		181.3		78.9		191.1		146.3		34.5		2090.4	
2010	444.9		188.0		81.8		197.7		150.0		35.8		2161.5	
2011	456.0		194.9		84.8		204.3		153.6		37.0		2235.0	
2012	467.4		202.1		88.0		211.0		157.2		38.3		2310.9	
2013	479.1		209.6		91.2		217.7		160.9		39.6		2389.5	
2014	491.1		217.4		94.6		224.3		164.5		41.0		2470.8	
2015	503.4		225.4		98.1		231.0		168.2		42.5		2554.8	
2016	516.0		233.8		101.7		237.6		171.8		43.9		2641.6	
2017	528.9		242.4		105.5		244.3		175.5		45.5		2731.4	

APPENDIX E – CALCULATE NEW COMPOUND GROWTH RATE (10 YEAR)



2014 - SUMMER PEAK LOAD FORECAST

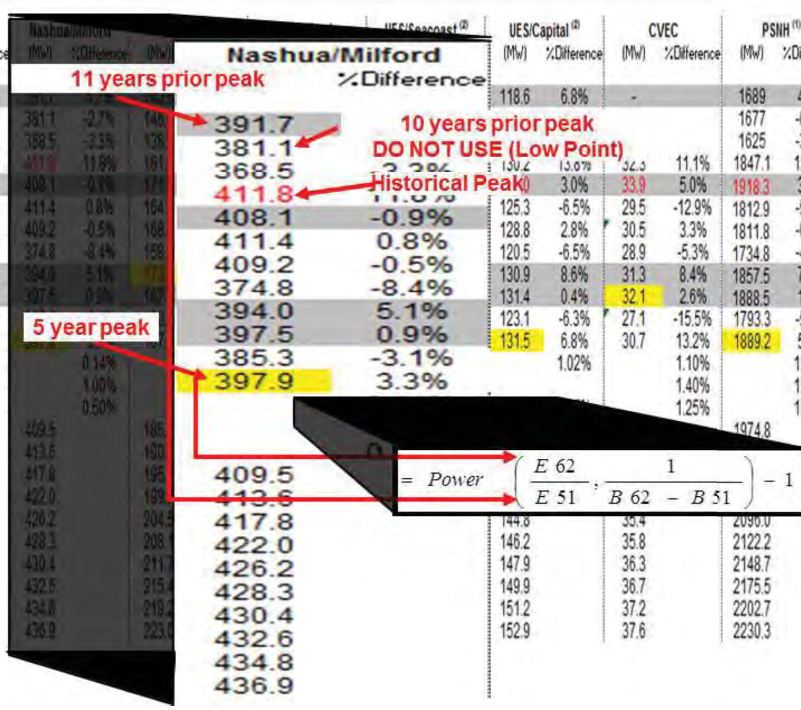
YEAR	Lakes Region (MW)	Lakes Region %Difference	<== Adjustment for Webster Valve	<== New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<== Adjustment for Safran & TurboCar	<== New Area Forecast	Manchester (MW)	Manchester %Difference	<== Adjustment for Velcro	<== New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	CVEC (MW)	CVEC %Difference	PSNH[1] (MW)	PSNH[1] %Difference
2002	211.1	1.5%	391.7	4.7%	140.6	2.1%	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	146.5	4.2%	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	138.7	-5.3%	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	161.4	16.4%	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	171.0	5.9%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	164.2	-4.0%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	168.8	2.8%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	158.5	[illegible]	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	173.2	9.3%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	167.7	-3.2%	[illegible]	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	160.7	-4.2%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	167.6	4.3%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		0.14%		1.69%		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		1.00%		2.40%		1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		1.75%		[illegible]		1.25%
2014	287.5		409.5		186.0		[illegible]		[illegible]	
2015	297.0		413.6		190.4		[illegible]		[illegible]	
2016	306.8		417.8		195.0		[illegible]		[illegible]	
2017	316.9		422.0		199.7		35.4		2096.0	
2018	327.3		426.2		204.5		35.8		2122.2	
2019	334.7		428.3		208.1		36.3		2148.7	
2020	342.2		430.4		211.7		36.7		2175.5	
2021	349.9		432.6		215.4		37.2		2202.7	
2022	357.8		434.8		219.2		37.6		2230.3	
2023	365.9		436.9		223.0					

APPENDIX F - CALCULATE NEW COMPOUND GROWTH RATE (OTHER THAN 10 YEARS)

2014 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	⇐ Adjustment for Webster Valve	⇐ New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	⇐ Adjustment for Safran & TurboCar	⇐ New Area Forecast	Manchester (MW)	Manchester %Difference	⇐ Adjustment for Velcro	⇐ New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	



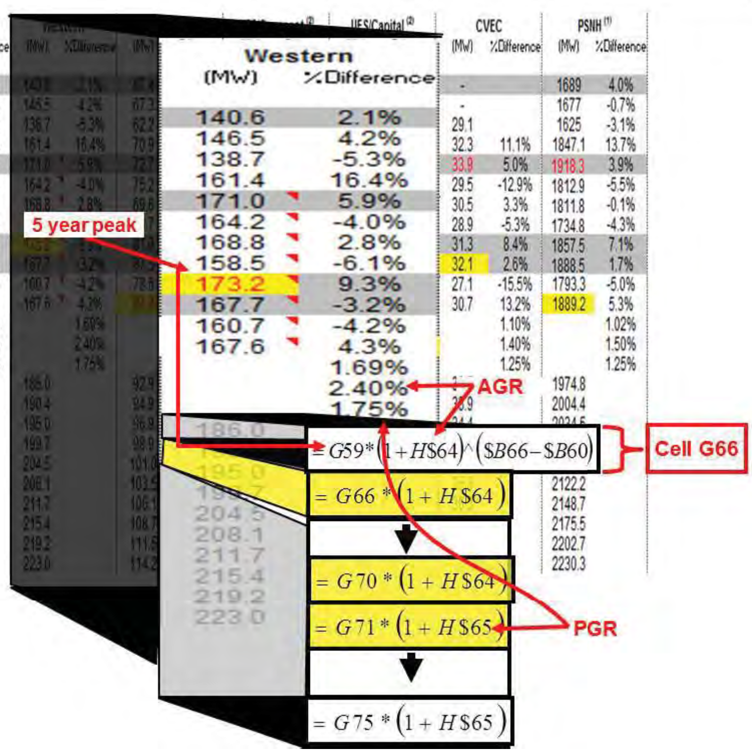
YEAR	Portsmouth (MW)	Portsmouth %Difference	UES/Capital (MW)	UES/Capital %Difference	CVEC (MW)	CVEC %Difference	PSNH (MW)	PSNH %Difference
2002	211.1	1.5%	118.6	6.8%	-		1689	4.0%
2003	213.3	1.0%					1677	-0.7%
2004	213.7	0.2%					1625	-3.1%
2005	250.1	17.0%	[illegible]	[illegible]	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	[illegible]	3.0%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	125.3	-6.5%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	128.8	2.8%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	120.5	-6.5%	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	130.9	8.6%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	131.4	0.4%	32.1	2.6%	1888.5	1.7%
2012	260.4	-0.2%	123.1	-6.3%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	131.5	6.8%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		1.02%		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%				1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%				1.25%		1.25%
2014	287.5						1974.8	
2015	297.0							
2016	306.8							
2017	316.9							
2018	327.3		144.8		35.4		2096.0	
2019	334.7		146.2		35.8		2122.2	
2020	342.2		147.9		36.3		2148.7	
2021	349.9		149.9		36.7		2175.5	
2022	357.8		151.2		37.2		2202.7	
2023	365.9		152.9		37.6		2230.3	

APPENDIX G - CALCULATE PROJECTED GROWTH

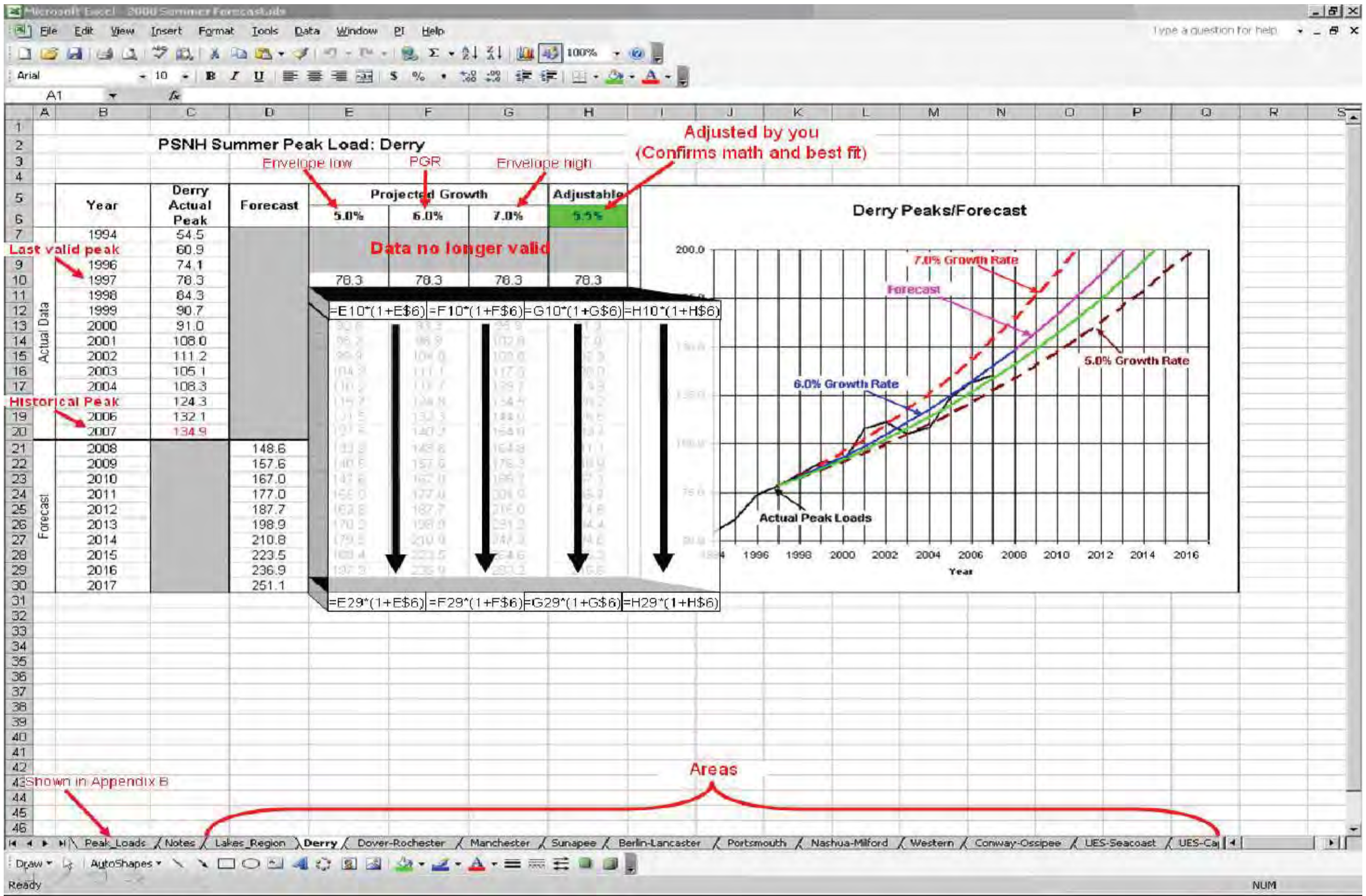
2014 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	<== Adjustment for Webster Valve	<== New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<== Adjustment for Safran & TurboCar	<== New Area Forecast	Manchester (MW)	Manchester %Difference	<== Adjustment for Velcro	<== New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	CVEC (MW)	CVEC %Difference	PSNH [1] (MW)	PSNH [1] %Difference
2002	211.1	1.5%	391.7	4.7%	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	32.1	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		0.14%		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		1.00%		1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		1.25%		1.25%
2014	287.5		409.5		[illegible]		1974.8	
2015	297.0		413.6		[illegible]		2004.4	
2016	306.8		417.8		[illegible]		[illegible]	
2017	316.9		422.0		[illegible]		[illegible]	
2018	327.3		426.2		[illegible]		[illegible]	
2019	334.7		428.3		[illegible]		2122.2	
2020	342.2		430.4		[illegible]		2148.7	
2021	349.9		432.6		[illegible]		2175.5	
2022	357.8		434.8		[illegible]		2202.7	
2023	365.9		436.9		[illegible]		2230.3	



APPENDIX H - UPDATE AREA CHARTS AND GRAPHS



VIII. Appendix D – ED 3002 Distribution System Planning and Design Criteria Guidelines

ED-3002 Distribution System Planning and Design Criteria Guidelines

I. PURPOSE

To establish guidelines to assist in planning and designing a distribution system that meets customer needs and regulatory requirements.

II. AREAS/PERSONS AFFECTED

This procedure applies to:

- Energy Delivery - system planning and design personnel

III. POLICY

It is the policy of PSNH:

A. To provide a reliable, cost effective, and efficient distribution system to meet customer needs while meeting regulatory requirements.

B. To insure adequate power distribution capacity during all times including normal summer and winter **peak load conditions**.

C. To examine **contingent** outages of substation equipment and circuits to identify areas subject to risk.

D. To insure a consistent approach to the planning for expansion and enhancement of the local area system.

E. To use sound engineering judgment when recommending construction for long term solutions when the design guidelines are exceeded.

F. To design the 34.5 kV distribution system to maximize performance and minimize cost by adhering to design criteria as outlined in this procedure.

IV. DEFINITIONS

Throughout the guideline, defined terms appear in bold and have a specific definition, which can be found in Appendix A.

V. OVERVIEW

This Operating Procedure provides distribution system design and planning guidelines for the 34.5kV and below systems. The 115kV and 345kV transformation to 34.5kV is included.

It is the intent of this guideline to promote the development of long term system solutions based on sound engineering and financial judgment. Short-term solutions **shall** be utilized only when prudent in the long-term planning of the system.

VI. PERIODIC REVIEW OF GUIDELINE

The Procedure Owner is responsible for maintaining this guideline and keeping current with good engineering design practices. The Procedure Owner for this Energy Delivery Procedure is the Manager of System Planning and Strategy or designee.

Annually, the Procedure Owner **shall** review design guideline for conformance to standard engineering practices and industry criteria to determine if the guideline **shall** be revised, rewritten, or cancelled.

As required, the Procedure Owner **shall** recommend changes to the Director of Energy Delivery. If approved by the Director, the Procedure Owner **shall** change the Procedure in accordance with AP-2001 Writing and Publishing Procedures.

VII. GUIDELINES

A. Normal Operation

Normal Operation is how the system is designed to operate during **peak load conditions**. The system **shall** be designed such that during normal operation no switching is required to maintain equipment within its normal thermal ratings.

For design purposes, the system **shall** be capable of serving native PSNH load during **peak load conditions** without relying on the facilities of customers or neighboring utilities unless in accordance with a specific contract.

Areas that may require system enhancements for Normal Operation are identified when **distribution power transformers** are loaded to within 85% of their **TFRAT** (transformer rating). Those areas will be specifically evaluated in order to determine proper budget and construction schedule such that system enhancements are in place the year prior to distribution power transformers exceeding their TFRAT. Refer to ED-3023, Appendix B, for guidance.

No load loss **shall** be permitted under normal Summer or Winter **peak load conditions**.

Each **system generator** will be modeled on and off during **peak load conditions** to assure adequate supply to the area. One generating unit at a time or the largest unit at a facility will be removed from the system model to examine the effect.

Distribution circuits to which **Independent Power Producers (IPP)** are connected will be designed to carry load in accordance with IPP contractual guidelines. IPP will be modeled on, off, and at varying power factors in accordance with the generator capabilities.

The use of **dispatchable peak shaving generation** as defined in Appendix A is acceptable for managing peak load issues in specific locations to manage capital investments on the system.

Known common supply conditions for generation facilities will be considered for impact on the system. This includes the effect of drought on all hydro-electric generation in an area, common fuel/gas supplies for multiple generation units, air emission standard constraints, etc.

B. Contingent Operation

Contingent Operation is the result of the failure of equipment during **peak load conditions**. The following **contingencies shall** be examined for system impact during **peak load conditions**.

1. Loss of 34.5 kV line breaker.
2. Loss of a **distribution power transformer**.
3. Loss of radial transmission lines.
4. Loss of non-radial transmission lines.
5. Loss of **dispatchable peak shaving generation**.

Each **system generator** will be modeled on and off during Contingent Operations. The reliability and ability to utilize the generation during **peak load conditions** will be examined in the event that a specific generating facility supports the system during Contingent Operation.

During Contingent Operation some loss of power to customers (load isolation) will be accepted at the time of **peak load conditions**. The following guidelines **shall** be used to determine the level of severity and need for construction:

1. The load isolation does not exceed 30 MVA and the duration of the outage does not exceed 24 hours.
2. **Load block transfers** on the 34.5kV system are an acceptable means for reducing exposure and typically **shall** not exceed three.

This design criteria recognizes that most PSNH transformers can be backed up by a mobile transformer or faulted circuits can usually be repaired in less than twenty-four hours unless under very adverse conditions.

Unitil	Guidelines	Procedure No.	GL-DT-DS-01
	Distribution Engineering	Section No.	A-A
		Page No.	16
	Electric System Planning Guide	Revision No.	4
		Revision Date	02/09/2016
		Supersedes Date:	03/13/2014

Appendix A – Design Guideline Summary

Design Condition	Load Level	Generation	Allowable Element Loading		Allowable Loss of Load	
			Limit[1]	Duration	Limit	Duration
Normal Configuration – all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ up to half of internal, non-utility generating units out of service	≤ Normal	Continuous	none	---
outage of generating plant			≤ Normal	Continuous	none	---
Contingency Configuration – loss of non-radial line			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
loss of a Unitil system supply transformer			≤ LTE	Per transformer rating summary	none	---
loss of radial line (no backup tie)			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
*loss of an external system supply transformer			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Extreme Peak – all elements in service	≤ Extreme Peak Load		≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

(S) = Summer load cycle
(W) = Winter load cycle

* Loss of load up to these limits is allowed in cases where Unitil distribution service is supplied by another utility from a site without an on-site back-up transformer. This criteria is intended to facilitate the installation of a mobile transformer in order to restore load.

[1] STE loading is acceptable following a loss-of-element contingency, provided actions are available to relieve the loading within 15 minutes.

nationalgrid

Distribution Planning Guide

Rev. 1

Approved by: ____________ **Date:** 2/15/11

Patrick Hogan, Sr. VP
Distribution Asset Management
National Grid USA Service Company

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document		

Distribution Planning Criteria Strategy
Table of Contents

Strategy Statement

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

For normal loading conditions, all types of facilities are to remain within their normal ratings at all times. For N-1 contingency situations it is expected that load shall be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair of a failed device. Where practical, switching flexibility should be integrated into the system design to minimize the duration of customer outages following an N-1 contingency to meet reliability objectives. The following shall guide contingency planning on the distribution system:

1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.) For the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

3.) For the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

Application of these criteria will result in somewhat less load at risk than previous criteria in either New York or New England which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 1:

Table 1 - Comparison of Capital Costs between Existing and New Criteria

Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in an increase in capital requirements up to $50M/year over the existing criteria for the 15-year period studied.

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities may be required over the next 15years.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long-term strategy and it is expected to take the full 15 year horizon to achieve compliance with existing facilities system-wide.

Performance targets for the adoption of the new planning criteria are:

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.

- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0 1	10/14/2009 2/15/2011	Initial draft Final approved document	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management

Strategy Justification

1.0 Purpose and Scope

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

A map showing National Grid electric service territory within New England and upstate New York is attached in Appendix A.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of National Grid is comprised of all lines and equipment operated at a voltage below 69kV in New England and below 115kV in New York. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within National Grid are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level. In Upstate New York approximately 70% of the substations have either a single source or a single transformer. In New England 40% of the substations have a single source and/or transformer.

A typical substation involves a 115/13 kV, 25-40 MVA rated transformer with either a load tap changer built into the transformer or individual voltage regulators applied to the feeders. In many locations, two or three transformers are within one substation and will interconnect via bus tie breakers. Many of the distribution substations supplied by the 115kV circuits also include one or more capacitor banks for reactive support.

National Grid maintains approximately 680 distribution substations containing approximately 1,530 power transformers. The total number of distribution substations, transformers, circuit miles of overhead and underground within NE and UPNY is listed in Distribution Line Overarching Strategy paper dated July 2008.

2.1.2 Sub-Transmission systems

The sub-transmission system within National Grid is designed to provide adequate capacity between transmission sources and load centers at reasonable cost and with minimal impact on the environment. The National Grid sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are neither bulk transmission nor distribution. The typical voltages for the sub-transmission system include 46, 34, and 23 kilovolts. In New York, the sub-transmission also includes the 69 kV.

Sub-transmission systems may be designed in a closed or open loop system originating from transmission substations, and generally providing a redundant supply for distribution substations. In other cases, a single radial sub-transmission supply line may serve load. The substations served from a sub-transmission line will serve approximately 10-40 MW of load depending on the voltage.

Generally, the sub-transmission system is presently designed with conductors ranging from 336.4 ACSR (UPNY) to 795 kcmil AAC (NE) overhead conductor and from 500 to 2000 kcmil copper underground conductor. However, most of the sub-transmission lines are older designs and built with smaller wire such as 2/0 AWG copper installed along right-of-ways or on public streets.

There are approximately 930 sub-transmission lines in New England and upstate New York within National Grid.

2.1.3 Distribution Feeders

Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductor. Feeders are designed in a radial configuration. The feeder mainline will typically have several normal open tie points to one or more adjacent feeders for backup. Protection for faults on the feeders consists of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits.

The National Grid Primary distribution system in New England and upstate New York is comprised of approximately 3,770 feeders.

2.1.4 Secondary Networks

Low voltage secondary networks have historically been employed in several urban areas to maximize the reliability for the customers in these areas. They typically have a 120/208V class secondary system that is connected as a grid with many downtown customers connected. Most of the secondary networks have from 4-10 supply feeders. The low voltage secondary network supply feeders will typically have 10-30 network transformers connecting into the secondary grid.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, 2-3 supply feeders are used to serve the spot networks.

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for New England and New York will be based on a regional econometric regression model that considers historic loading, weather conditions, various economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years. Separate models are used for NE and UPNY.

2.2.1.2 Equipment Ratings

Distribution Planning maintains equipment ratings for New England and New York. The summer and winter normal and summer and winter long time emergency (LTE) ratings will be used. The major equipment ratings to be used by Distribution Planning relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for these items may be applied for the time associated with each rating. Generally, the durations for emergency loading are as listed below in Table 2. System operators must be aware of the limiting factor involved in any contingency:

Table 2 - Equipment Rating Durations

Equipment		Normal	LTE	STE
Transformer		Continuous	24 hour	15 Min
Overhead Line		Continuous	24 hour	N/A
Underground Cable		Continuous	24 hour	N/A

There is also a short time emergency rating which may be determined for substation transformers, in no instance should this rating exceed 200% of nameplate rating. In addition to the items in the above table, ratings are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers.

2.2.1.3 Planning Study Areas

A planning study area within National Grid is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in NE and UPNY to be used by Distribution Planning are presented in Appendix B.

2.2.1.4 Load Flows

Distribution planning studies will utilize the PSS/e load flow program for the study of the sub-transmission lines and networks. The distribution feeder load flow analyses will be done using the Cymedist feeder analysis software program.

2.2.1.5 Distribution Analysis Alternatives

When performing distribution system analyses, Distribution Planning shall consider both traditional capacity enhancements as well as alternatives for "Non-Wires" customer load management alternatives where appropriate. The factors below could impact capacity planning analysis

a. Distributed Generation
b. Controllable Load Curtailment
c. Energy Storage devices
d. Demand Side Management

e. Distribution Automation
f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods.

2.2.2.2 Contingency N-1 substation transformer planning criteria

For an N-1 contingency condition that would involve the loss of a power transformer or substation bus, the following planning criteria apply:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

Many locations with two or more transformers at a substation utilize automatic bus transfers. In some stations, one bus tie breaker is used, while in other substations a breaker and half design is utilized and there may be several feeder bus tie breakers. Based on the loading limitations in Section 2.2.2.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during an N-1 contingency. Cases where automatic restoration are disabled will be documented and communicated with Regional Control Centers as part of an annual summer preparedness review. Recommendations to add capacity to the area will be evaluated and prioritized based load at risk, reliability and cost with other Load Relief alternatives.

When available, the use of the Energy Management System (EMS) control shall be implemented as needed to block automatic transfer. During an N-1 contingency, the System Operator will be required to maintain the loading on transformers as specified in Section 2.2.2.2.

2.2.2.4 Substation reactive support criteria

Reactive compensation shall be required for substations in the form of station capacitor banks or static VAR compensators. These should be sized to offset the reactive losses of the transformers at full load. Two or three stage capacitor banks may be needed for larger transformers to manage power factor and to limit voltage fluctuations.

2.2.2.5 Impact of planned maintenance

Capacity in all areas should allow the off loading of any distribution substation transformer for planned maintenance during the off peak months without exceeding the normal ratings of the other area equipment. However, in areas of the system with limited feeder ties, it may be more economical to allow the installation of a mobile transformer for maintenance.

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

A sub-transmission supply line will not be loaded above its normal rating during non-contingency operating periods.

2.2.3.2 Contingency N-1 sub-transmission planning criteria

For an N-1 contingency condition that would involve the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Load on the remaining sub-transmission line will need to be reduced to normal levels within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The limit of load at risk for the loss of any sub-transmission line will be 20MW.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.3.3 Automatic line transfer systems

Auto transfer of load on the sub-transmission may be employed, but may not exceed the emergency (LTE) ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

2.2.3.4 Sub-transmission reactive support criteria

Reactive compensation for sub-transmission lines shall be required in the form of station and distribution capacitor banks.

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

A distribution feeder circuit will not be loaded above its normal rating during non-contingency operating periods.

2.2.4.2 Contingency N-1 feeder planning criteria

For an N-1 contingency condition that would involve the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.4.3 Automatic transfers on feeders

In some cases, it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers.

2.2.4.4 Feeder reactive support criteria

Reactive compensation for feeders should be installed to provide additional capacity, improve voltage regulation and meet external power factor standards where applicable. A mixture of fixed and switched capacitor banks may be used as needed. All feeders in a planning area shall have proper reactive compensation prior to any requests for other load relief infrastructure improvements.

2.2.4.5 Feeder load balance criteria

Distribution Planning studies are based on three phase average loading. Load balance between the three phases on any feeder is assumed to be within a reasonable level.

Distribution feeder load balance shall require correction of the load imbalance for either of the following cases:

- Any feeder with the calculated neutral current exceeding 30% of the feeder ground relay pickup setting.

- Any feeder exceeding 100A between the high and low phase amps.

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution standards. The criteria are different for NE and UPNY based on the history of how various networks evolved.

2.2.6 Voltage criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

The normal and emergency voltage to all customers shall be in line with limits specified by state regulators and within the limits of ANSI C84.1

These upper and lower voltage limits for each state in the service territory are listed in Table 3 below:

Table 3 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New Hampshire	126	120	114
New York	123	120	114
Rhode Island	123	120	113

The values in Table 3 are in line with the National Grid Overhead Construction Standards.

Voltage on the sub-transmission and primary feeders is determined by many factors including:
- Primary mainline conductor sizes
- Distance of lines
- Reactive compensation

Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or padmounted line regulators. Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 3 above are maintained.

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

The goal of the new planning criteria is to maintain the performance of the electric distribution system. Generally, after compliance with the new criteria, the residual risk for the worst case will be 10 MW of load out for 24 hours for a substation transformer failure or 20 MW out for 12 hours for an overhead supply line failure.

2.3.2 Methodology to prioritize capital projects

Prioritization of capital projects utilizes scoring system that considers the consequence of not completing the project and the probability that the consequences will be realized. A risk score between 1 and 49 is developed utilizing a 7x7 scoring matrix.

3.0 Risks/Benefits

The principal impacts of the planning criteria are reliability performance, customer service and efficiency. Due to the extended time frame for strategy compliance, the impact of the strategy will not be initially visible at the system level. These benefits will be most apparent in those areas where it has been implemented.

3.1 Safety & Environmental

Safety and environmental factors are not principal drivers of the planning strategy. However, the planning criteria will ensure equipment loading is maintained within accepted ratings reducing the risk of premature equipment failure that could result in environmental and public safety concerns.

3.2 Reliability

The planning criteria will provide operating flexibility to facilitate the restoration of customer outages following an N-1 contingency event. With an expected long implementation schedule, the impact will not be initially visible at the system level but will be significant in the areas where the criteria have been implemented. A long range reliability improvement of 11.4 minutes in SAIDI and 0.073 in SAIFI on a system basis is forecasted if the strategy is implemented over a 15 year planning horizon. Additionally, lower feeder loading will support future distribution automation to further improve reliability.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers.

3.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation and study area loading analysis across NE and UPNY. All studies being conducted under one criterion will create a consistent reference for ranking projects as part of the business planning process.

4.0 Estimated Costs

The estimated costs to adopt the new planning criteria are summarized as follows:

The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 4:

Table 4 - Comparison of Capital Costs between Existing and New Criteria

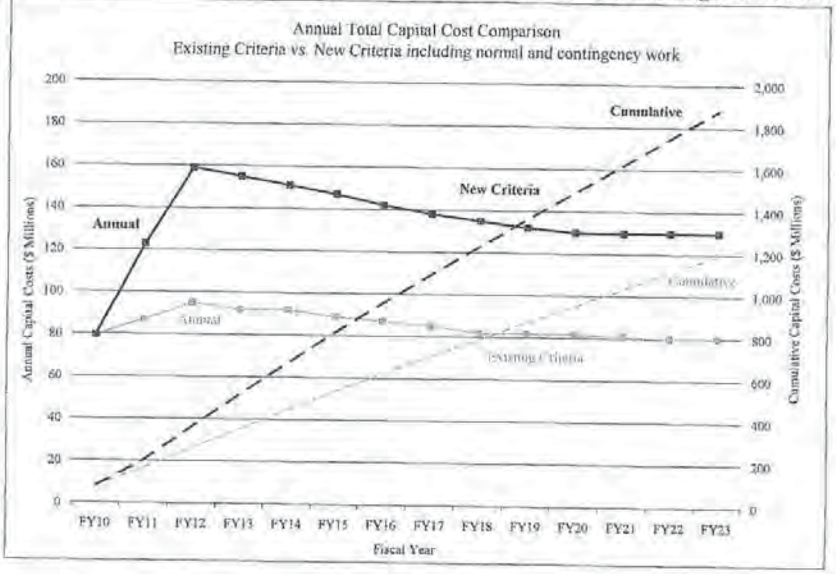
Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in increased in capital costs of $50M/year in the Load Relief budget category compared to previous criteria for the 15-year period studied.

Based on an analysis of normal loading issues, it is projected that capital work associated with normal loading will remain at present levels or slightly higher for several years and then ramp down as contingency projects will tend to drive the load relief spending.

These combined normal and contingency capital costs are shown in Figure 1 below:

Figure 1 - Annual and Cumulative Capital Cost Comparison between Existing and New Criteria



5.0 Implementation

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities are forecasted to be required over the next 15 years in NE and UPNY.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long term strategy and it is expected to take many years to implement system-wide.

6.0 Data Requirements

The data sources required for the proper execution of the planning strategy include:

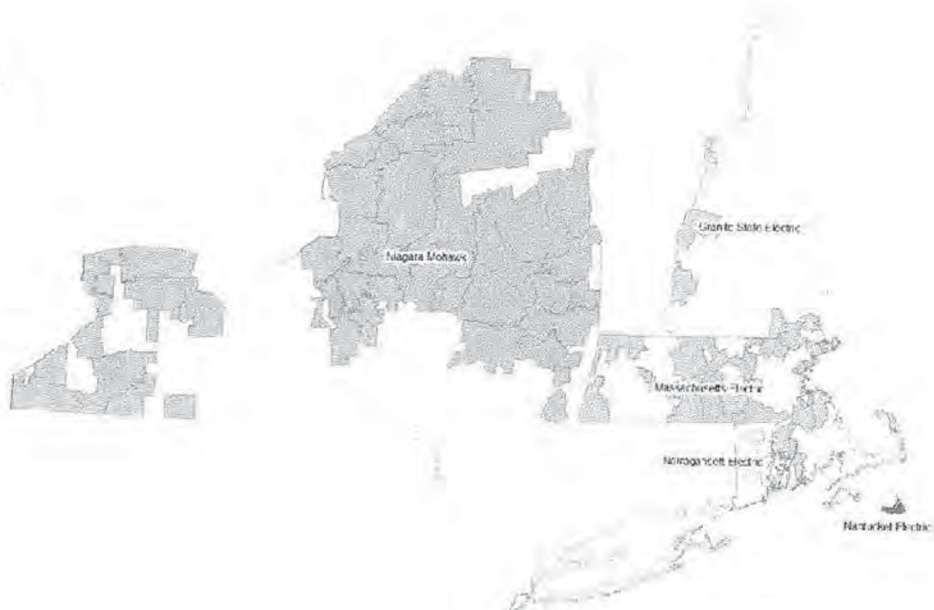
6.1 Planning Tools:

Cymedist (Cyme) – for radial feeder load flow and voltage analysis
Smallworld GIS – to support Cyme analysis
PSS/e – for network load flow analysis
FeedPro - for equipment loading and ratings
EMS and PI or ERS access in NE and UPNY

Appendix A – Service Territory Maps

Maps of Electric Distribution Service Territories for five companies and five divisions:

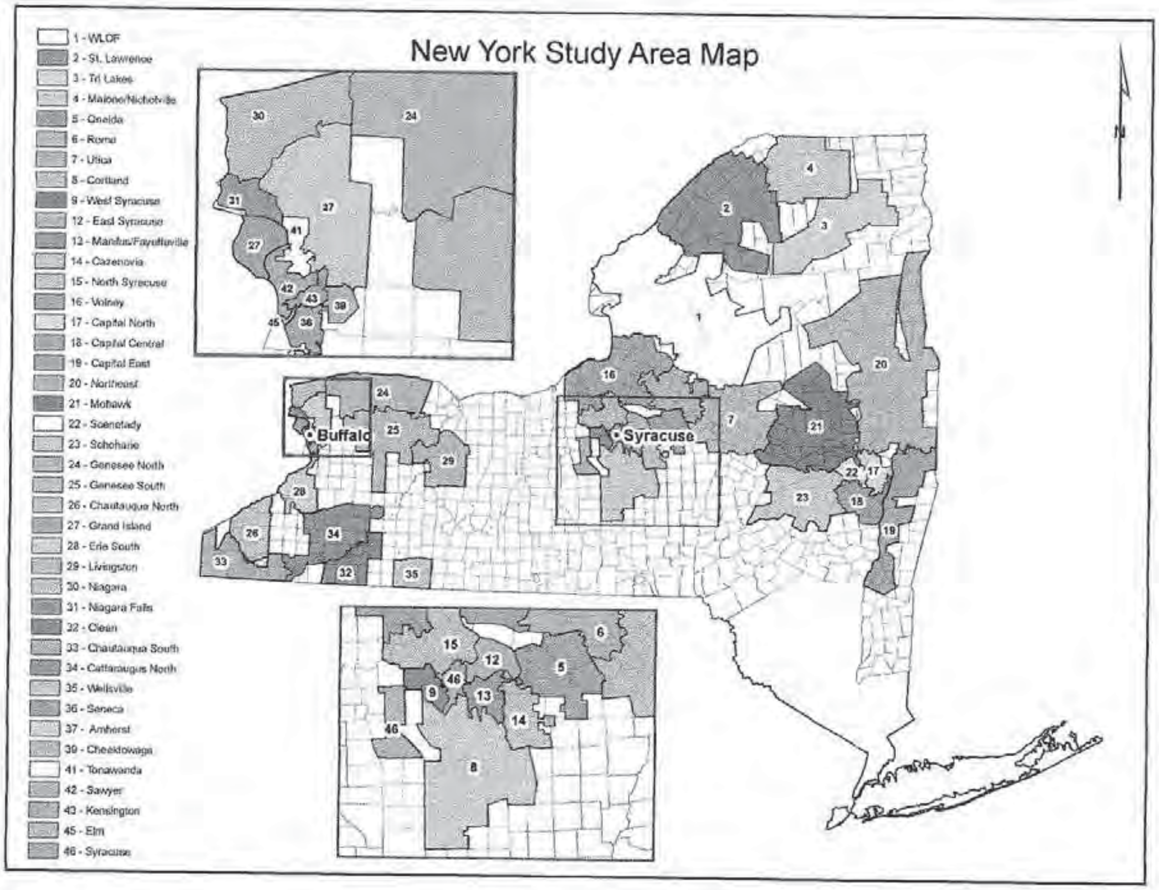
Companies

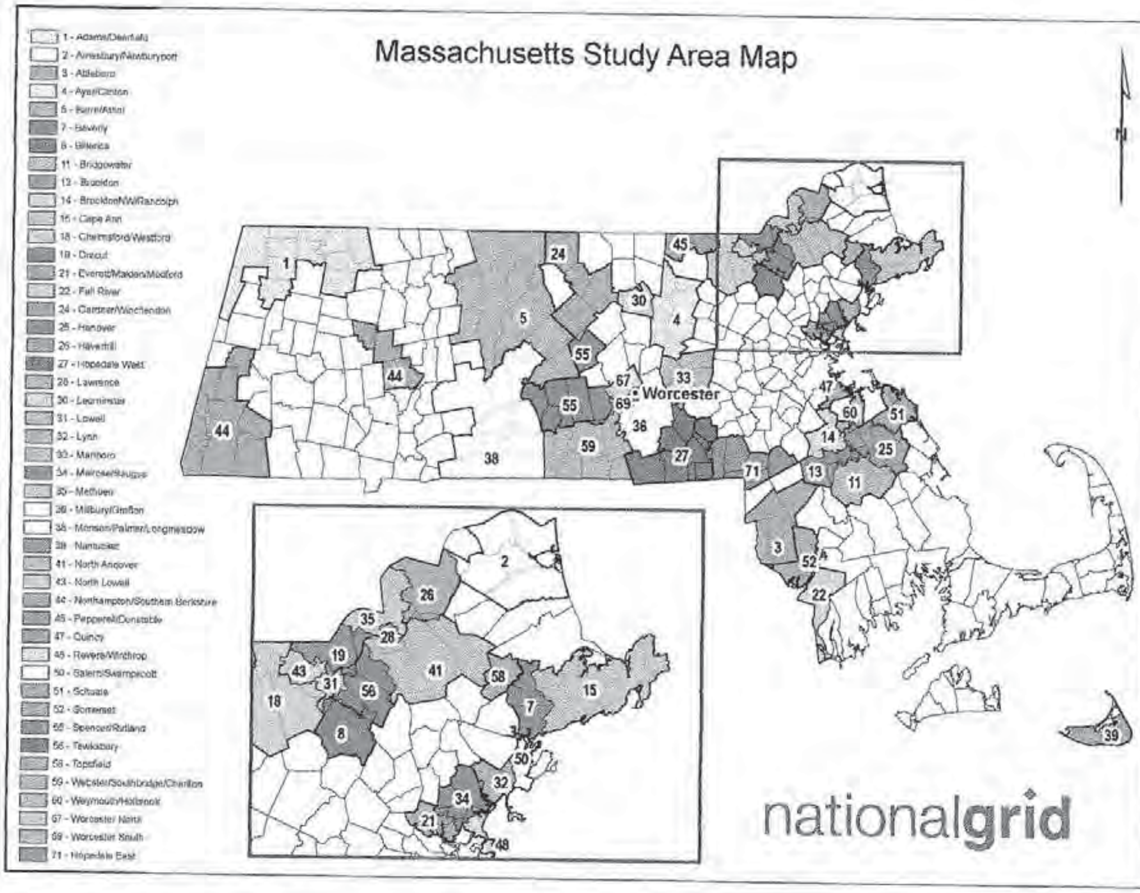


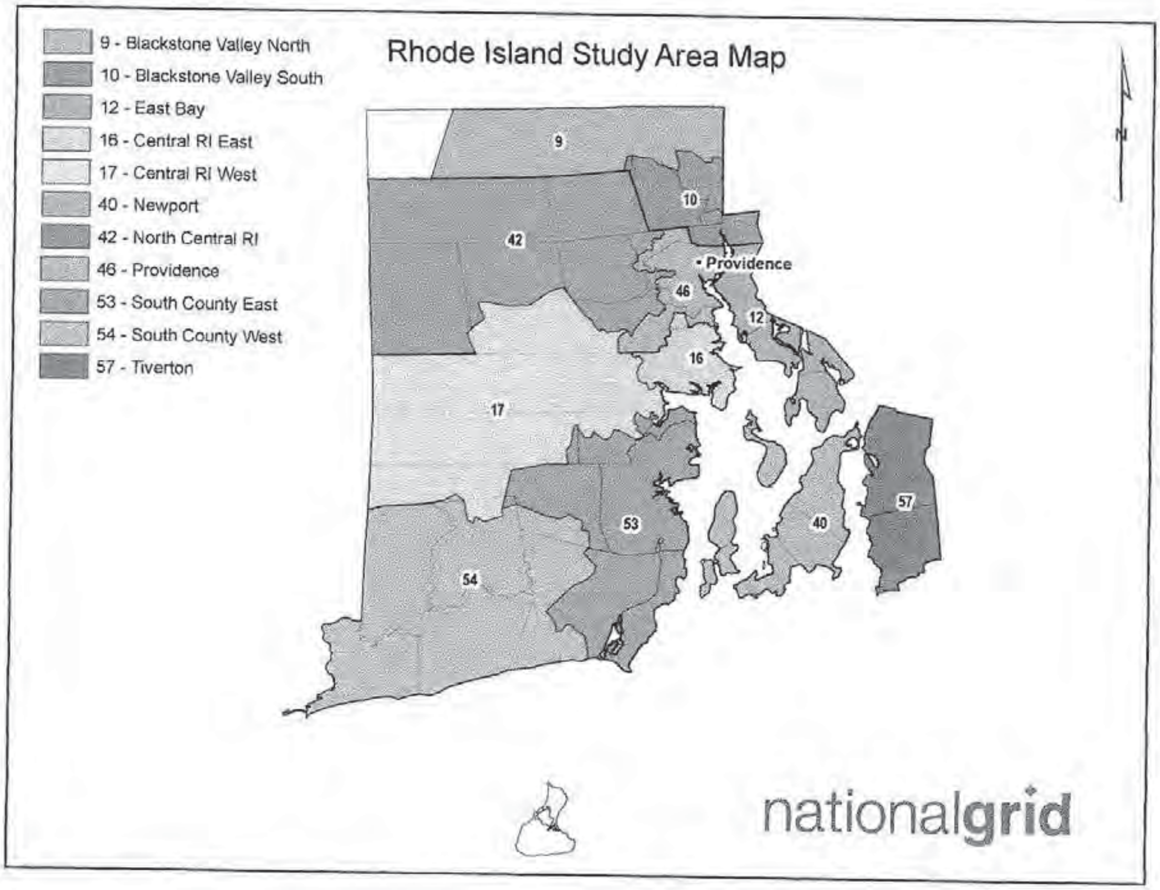
Divisions

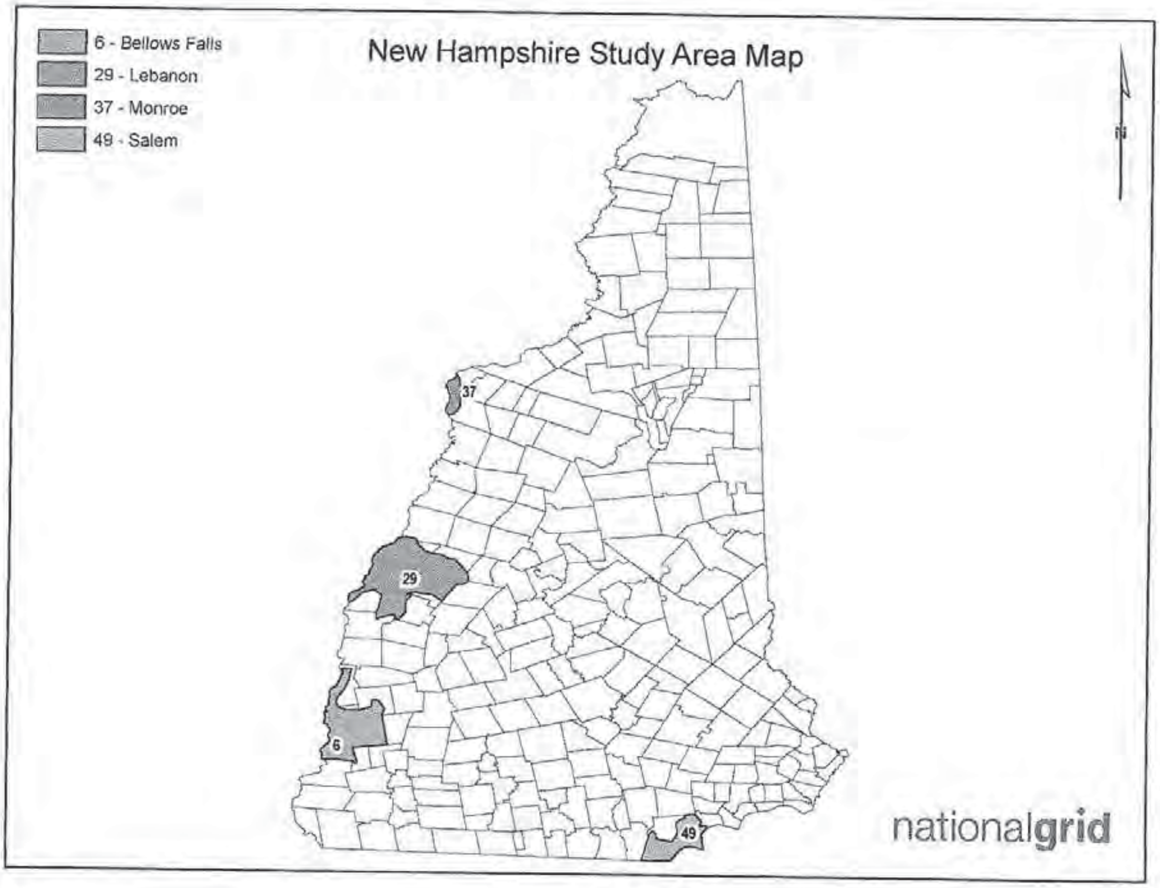
Appendix B - Distribution Planning Study Areas

To foster the annual capacity planning assessment, the distribution system across UNY and NE has been segmented into Planning Study Areas as shown in the following figures.




Massachusetts Study Area Map
1 - Adams/Deerfield
2 - Amesbury/Newburyport
3 - Attleboro
4 - Ayer/Clinton
5 - Barre/Athol
7 - Beverly
8 - Billerica
11 - Bridgewater
13 - Brockton
14 - BrocktonNW/Randolph
15 - Cape Ann
18 - Chelmsford/Westford
19 - Dracut
21 - Everett/Malden/Medford
22 - Fall River
24 - Gardner/Winchendon
25 - Hanover
26 - Haverhill
27 - Hopedale West
28 - Lawrence
30 - Leominster
31 - Lowell
32 - Lynn
33 - Marlboro
34 - Melrose/Saugus
35 - Methuen
36 - Millbury/Grafton
38 - Monson/Palmer/Longmeadow
39 - Nantucket
41 - North Andover
43 - North Lowell
44 - Northampton/Southern Berkshire
45 - Pepperell/Dunstable
47 - Quincy
48 - Revere/Winthrop
50 - Salem/Swampscott
51 - Scituate
52 - Somerset
55 - Spencer/Rutland
56 - Tewksbury
58 - Topsfield
59 - Webster/Southbridge/Charlton
60 - Weymouth/Holbrook
67 - Worcester North
69 - Worcester South
71 - Hopedale East
Worcester
N
nationalgrid


9 - Blackstone Valley North
10 - Blackstone Valley South
12 - East Bay
16 - Central RI East
17 - Central RI West
40 - Newport
42 - North Central RI
46 - Providence
53 - South County East
54 - South County West
57 - Tiverton
Rhode Island Study Area Map
9
10
42
Providence
46
12
16
17
53
40
57
54
N
nationalgrid


6 - Bellows Falls
29 - Lebanon
37 - Monroe
49 - Salem
New Hampshire Study Area Map
N
37
29
6
49
nationalgrid

1 Abstract

Adequate distribution capacity is key to overall system reliability and proper functioning of system facilities. The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The loading of the system has changed over the years to where various components are at or have exceeded certain planning and operating criteria. In addition, sub-transmission facilities in the area are approaching its design limits. The upcoming developments in the area result in an increase of components exceeding planning and operating criteria.

This Area Study is being carried out to study five (5) possible options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. The recommended plan accomplishes all system capacity and asset replacement requirements. The plan will be achieved in three (3) phases. The first phase recommends the installation of a 115/13.2 kV - 33/44/55 MVA transformer and four 13.2kV feeders at the Golden Rock Substation and the retirement of Baron Avenue Substation. The second phase installs a new double-ended 115/13.2kV substation Rockingham #21 and eight 13.2kV feeders in the Rockingham Park Track and retires the Salem Depot Substation. The third phase replaces the existing 115/23kV transformer at Golden Rock with a 115/13.2kV – 33/44/55 MVA transformer and four 13.2kV feeders and converts the Olde Trolley Substation to a switching/regulator station, and retires the 23kV sub-transmission system in the area. This recommendation is based on the engineering analysis to find the most economical alternative to provide for projected load growth, contingency mitigation, and to asses condition issues of the existing equipment.

2 Executive Summary

Control Point Technologies with the assistance of Liberty Utilities has completed the Salem, NH distribution planning study. The Liberty Utilities Distribution Planning Criteria was used to determine any Electric Supply System upgrades required to meet existing and future capacity requirements. The study focused on the distribution requirements needed to supply the proposed business park development in the range of 14MW – 17MW located at the former Rockingham Park Track. The study also focused on the retirement of Baron Ave Substation, Salem Depot Substation and Olde Trolley substation due to issues with asset condition. The retirement of these substations will set the stage for the retirement of the Salem Area 23kV sub-transmission system.

The Distribution System under study included:

- One (1) 115kV/23kV substation Golden Rock No.19.
- Four (4) 23kV sub-transmission (supply) circuits, 2352, 2393, 2353 and 2376.
- Four (4) 23kV/13.2kV substations, Baron Ave No.10, Olde Trolley No.18, Salem Depot No. 9 and Spicket River No 13.
- Thirteen (13), 13.2kV distribution circuits, 10L1, 10L2, 10L4, 18L1, 18L2, 18L3, 18L4, 9L1, 9L2, 9L3, 13L1, 13L2 and 13L3.

2.1 Explanation

The study, focused on current and future capacity needs of the supply lines, substations and distribution system supplying the area along with the asset conditions of the existing electrical infrastructure. Evaluations identified a number of existing and predicted system Distribution Circuit, Supply Line, and Transformer capacity concerns that did not meet the requirements of the Liberty Distribution Planning Criteria.

Existing Criteria violations, based on 2016 peak loading, were identified for both the Normal Loading and the Contingency Loading cases. These are detailed under Section 3.6 and include the following:

1. Conductor Thermal overloads in excess of 100% Summer Normal ratings on the, 18L4 circuit.

2. During Contingency (N-1) cases, the Salem Depot 9L2 Circuit violates the 16 MWH rule with 3.7 MVA of Load at risk.

3. During Contingency (N-1) cases the Spicket River Loss of 23kV Supply violates the 36 MWH rule with 8.9 MVA load at risk.

4. The 13L2 Circuit, which is limited to 515 Amps by 336 Al OH, exceeds 75% of its Summer Normal rating.

5. The 9L2 Circuit's transformer which is limited to 322 Amps exceeds 75% of its Summer Normal rating.

6. During Contingency (N-1) cases, the loss of supply or transformer at Golden Rock results in 12MW of unserved load, which violates the distribution planning criteria.

In addition to the existing distribution evaluation the study also focused on the distribution requirements needed to supply the proposed business park development in the range of 14 MW - 17 MW located at the former Rockingham Park Track.

Existing loading concerns and planning criteria violations amplify with the addition of the proposed business park and other known spot loads in the area. Existing transformer, distribution circuit and supply line capacity in the Salem area will be exceeded, presenting many challenges to the existing 23kV/13.2kV distribution system. These predicted criteria violations were identified by year for both the Normal Loading and the Contingency Loading cases under Section 3.7.

2.2 Recommended Plan

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4.

The study took into consideration existing distribution asset concerns while determining possible recommendations. These asset concerns are detailed in Section 3.3.

The recommended plan for consideration accomplishes all system capacity and asset replacement requirements. The plan will be achieved in three (3) phases. It addresses the existing concerns and the future concerns in the most complete way while moving the system from the legacy 23 kV supplied system to a more reliable and sustainable 115 kV supplied system. It also provides the capacity needed to supply the proposed business park development in the former Rockingham Park Track.

Phase One (New 115/13.2 kV Transformer at Golden Rock Station with Baron Ave Station Elimination & Spicket River Mitigation)

Phase One of the recommended plan consists of a second 115 kV transmission line into Golden Rock Station supplying a new 115kV/13.2 kV substation transformer with three (3) new 13.2 kV circuit positions. The 13.2 kV circuits would be constructed to provide contingency support to Spicket River Station and to eliminate the Baron Ave Station. It would also be used to mitigate forecasted capacity issues after initial Rockingham expansions in the range of 3MW – 5MW take place. The future circuit #4 will be installed during Phase 2 after the new underground conduit system along the right-of-way (ROW) is installed.

This phase would also include the replacement of existing conductor in excess of 100% of Summer Normal ratings, on the 18L4 circuit. The conductor upgrade would be accomplished using 477 Al spacer cable to the first protective device, then 477 Al open wire or 477 tree wire depending upon field conditions.

Phase One of the Recommended Plan also consists of the removal of the existing 23kV stub bus at the Golden Rock substation to make way for new 13.2kV equipment. The 2352 circuit will also be removed from Golden Rock to Baron Ave.

The total cost of the Phase One project is estimated at $5,584,000.

Phase Two (New 115/13.2 KV Transformers at New Rockingham Station with Salem Depot Station Elimination and Criteria Mitigation)

Phase Two of the recommended plan consists of an extension of the 115 kV transmission system from Golden Rock Station to a proposed new double ended 115kV/13.2kV station in the Rockingham Park Track area. Acquisition of land within the Rockingham Park will be required to install the new substation.

Each new 115 kV/ 13.2 kV supply transformer, T1 and T2, would have four (4) circuits, eight (8) total, with secondary breakers and a bus tie breaker. An automatic bus transfer system would be utilized to improve reliability and simplify maintenance.

Three (3) of the T1 supply transformer circuits would be used to supply a reconfigured 13.2 kV distribution system, which will bring the system into compliance with Liberty's Distribution Planning Criteria. The configuration would be targeted to improve reliability and better balance loading on all circuits.

Three (3) of the T2 supply transformer circuits would be used eliminate the Salem Depot Station and provide backup support to the Olde Trolley substation.

The fourth circuit on both the T1 and T2 supply transformers would serve the proposed business park load.

The two (2) 23kv supply circuits 2352 and 2393 will be relocated from OH to UG along the ROW to make way for the two (2) new 115kV transmission supply lines supplying the new Rockingham Substation. This new underground system along the ROW will also be used for future distribution feeders out of Golden Rock Substation (Phase 3) and for the fourth feeder out of Golden Rock T2.

The total cost of the Phase Two project is estimated at $20,648,000.

Phase Three (Install Second 115/13.2 KV Transformer at Golden Rock Station with Olde Trolley Elimination)

Phase three of the recommended plan consists of a second 115kV/13.2kV substation transformer at Golden Rock with four (4) new 13.2kV feeder positions.

The existing 115kV/23kV Golden Rock transformer is to be removed and the substation is to be converted into a 13.2kV with a breaker and a half scheme. The existing 23kV lines will be converted to 13.2kV distribution circuits. The 13.2 kV circuits would be constructed to provide contingency support to Rockingham Station and Spicket River Station. Phase Three of the Recommended Plan will convert the Olde Trolley Station into a regulating/switching station and will eliminate the 23kV supply system out of Golden Rock.

The total cost of the Phase Three project is estimated at $4,684,000.

2.3 Reasons for Recommendation

The recommended plan addresses existing and predicted normal and contingency operational, capacity, and asset challenges associated with the existing 23kV/13.2kV based distribution system. In addition, the plan addresses, capacity loading concerns developed with the addition of the proposed business park at the former Rockingham Park Track and other known spot loads in the area.

Additionally, Spicket River Station is presently supplied by one 23kV circuit fed from the Transmission Service Provider, National Grid. With the loss of this supply, the existing 13.2 kV circuit ties do not have sufficient capacity to pick up the entire station load on peak. The load at risk resulting from this contingency scenario violates the Liberty Distribution Planning Criteria. The added capacity and 13.2 kV circuits would be constructed from Golden Rock to provide contingency support to Spicket River Station and bring the station into compliance with Liberty's Distribution Planning Criteria.

The opportunity to move the system from a 23kV/13.2kV to a more robust 115kV/13.2kV substation transformer based system is presented. The 115kV/13.2kV transformers will allow larger capacity transformers to be utilized in supplying system demand. By utilizing the additional capacity available from the larger capacity transformers; Liberty Utilities can develop a multi-phased plan to eliminate existing 23 kV facilities, including Baron Ave, Salem Depot station and Olde Trolley, with their legacy maintenance and operational concerns. Also, the recommended plan will decrease the reliance on the 23 kV supply line system and its continued dependence on the Transmission Service Provider to allocate 23 kV capacity for Liberty Utilities.

2.4 Recommended One-lines

Refer to section 5.2 Recommended Plan One-lines, for Station and Distribution Systems.

2.5 Recommendation Estimates

The following tables provide estimated costs, by phase, for the Recommended Plan.

Recommended Plan Phase One Estimate	
Required Construction	**Cost - $k**
Baron Ave Station Elimination & Spicket River Mitigation Distribution Circuit Estimate	**$2,400**
Baron Ave Station Elimination & Spicket River Mitigation Sub-Transmission Circuit Estimate	**$184**
New 115/13.2 kV Transformer at Golden Rock Station Estimate	**$3,000**
Phase One Project Total	**$5,584**

Recommended Plan Phase Two Estimate	
Required Construction	**Cost - $k**
Salem Depot Station Elimination Distribution Circuit Estimate and Design Criteria Compliance	**$6,343**
Salem Depot Station Elimination Sub-transmission Circuit Estimate and 23kV Relocation.	**$8,504**
New 115/13.2 KV Transformer, T1, at New Rockingham Station Estimate	**$2,800**
New 115/13.2 KV Transformer, T2, at New Rockingham Station Estimate	**$3,000**
Phase Two Project Total	**$20,648**

Recommended Plan Phase Three Estimate	
Required Construction	**Cost - $k**
Olde Trolley Elimination Distribution Circuit Estimate	**$150**
Olde Trolley Elimination Sub-transmission Circuit Estimate and 23kV Supply Retirement	**$34**
New 115/13.2 kV Transformer at Golden Rock Station Estimate	**$4,500**
Phase Three Project Total	**$4,684**

If the implementation of a new Rockingham Station is significantly delayed, Salem Depot Station upgrades should be pursued due to issues with asset condition.

In addition, if the implementation of a new Rockingham Station is significantly delayed, the temporary installation of a 23/13.2kV 9.375 MVA transformer within the Rockingham Park should be pursued. One transformer from the retired Baron Avenue substation could be reserved for this application. Although this transformer and sub-transmission supply system would not have the full capacity to supply all of the forecasted expansions in the park, it could buy enough time to supply some new developments in the Park as the new Rockingham Station is being implemented.

Recommended Plan Phase Two Delay Estimate	
Required Construction	**Cost - $k**
Salem Depot Station Upgrades Station Estimate	**$1,550**
Phase Two Project Total (Delay)	**$1,550**

3 Introduction

The Salem, NH area distribution Study was completed to determine any Electric Supply System upgrades required to meet existing and future capacity operational and asset requirements. The study also focused on the distribution requirements needed to supply the proposed business park development in the range of 14MW – 17MW located at the former Rockingham Park Track.

3.1 Geographic Scope

This study was performed on the Liberty Utilities Distribution System supplying Salem, New Hampshire. The system is confined to the City of Salem, NH with small excursions into Windham and Derry, NH and Methuen, MA.

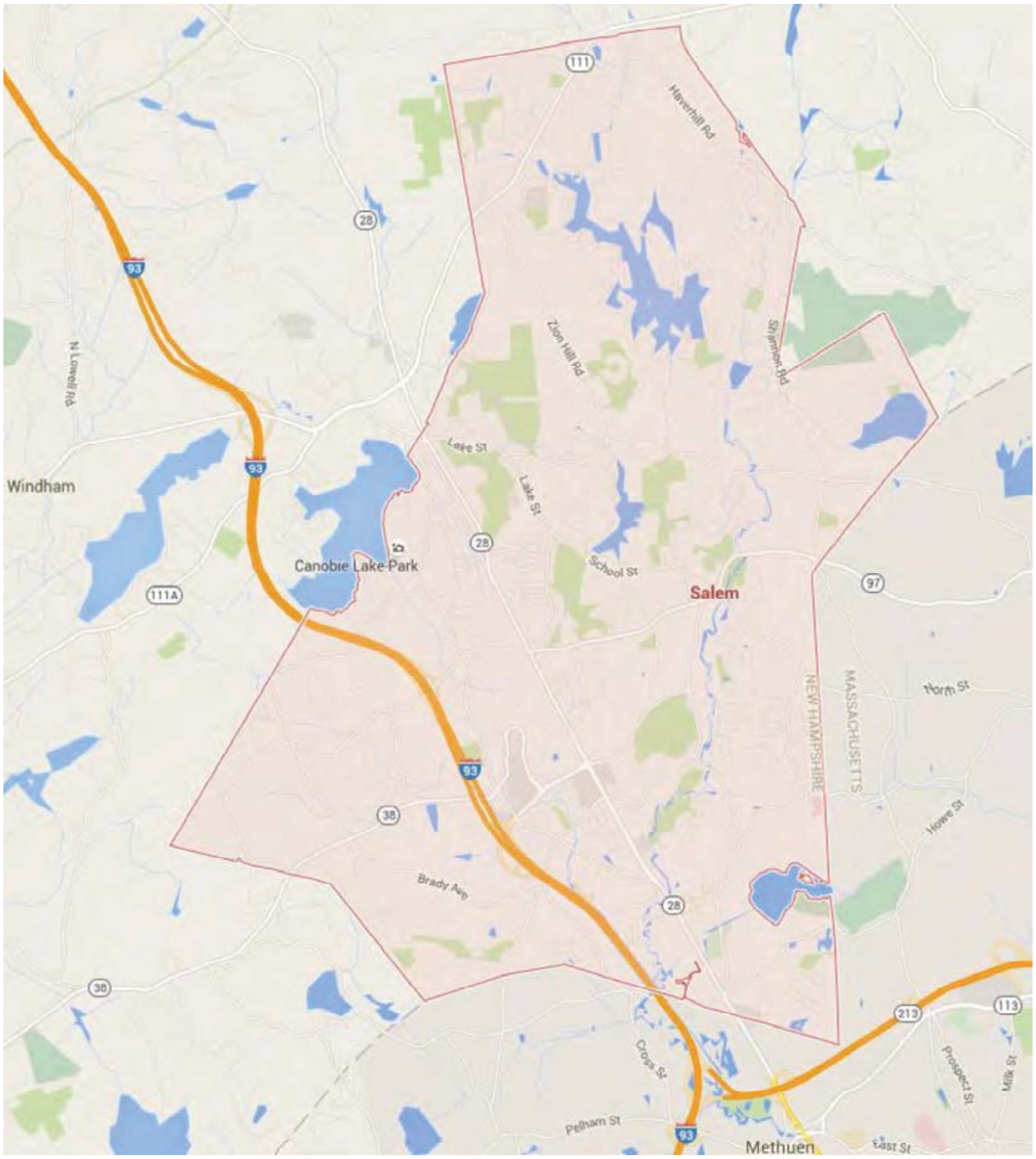


Figure 1 Salem, NH Geographical Map

3.2 Electrical Scope

The Distribution System under study includes the 2352, 2353, 2376, and 2393, 23 kV supply circuits; refer to *Figure 2, Salem Area 23 kV Supply System One-Line*. These circuits supply four (4) 23kV/13.2kV substations: Baron Ave No.10, Olde Trolley No.18, Salem Depot No. 9 and Spicket River No 13 and one 23kV customer station “Jockey Club”.

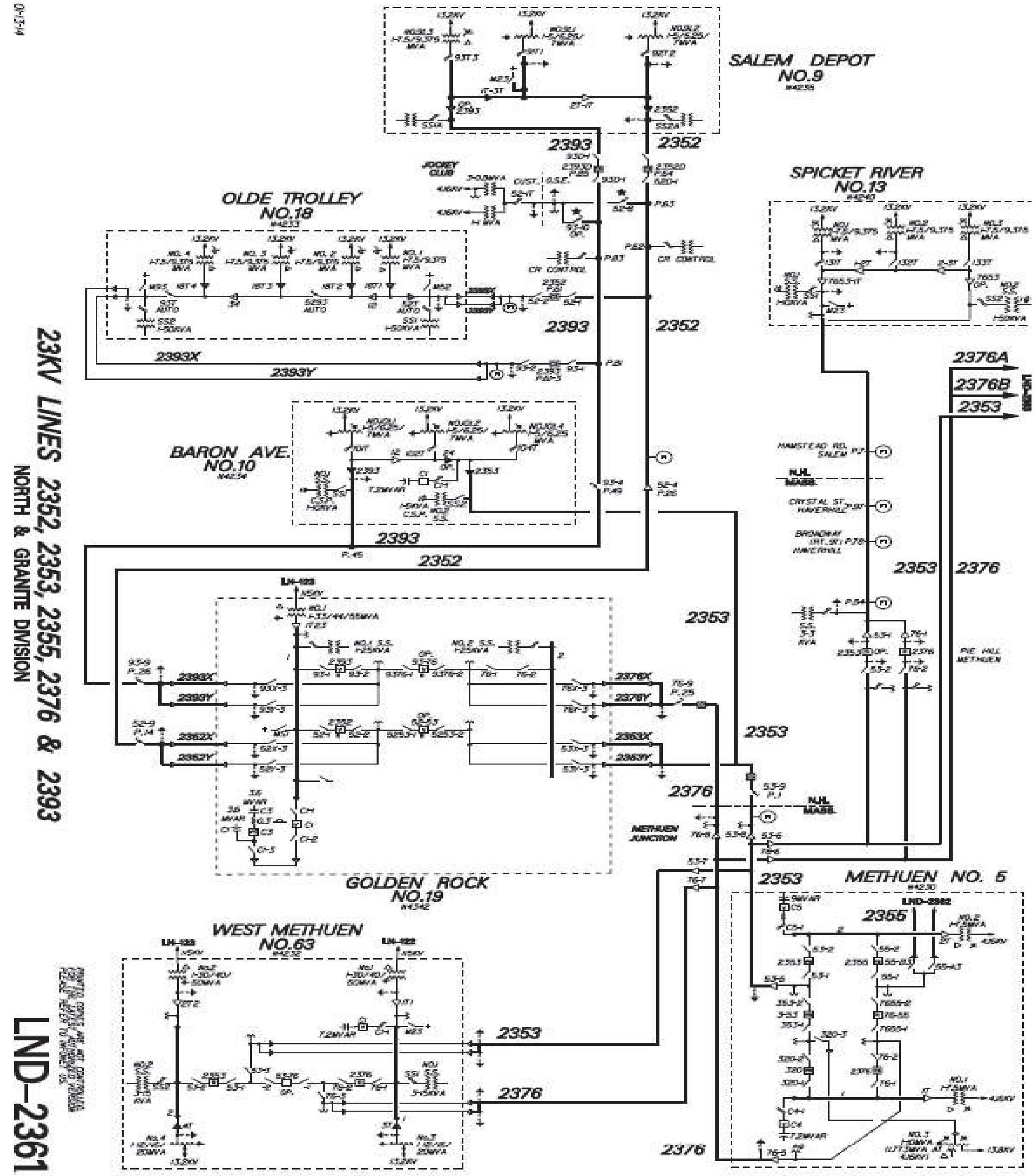


Figure 2 Salem Area 23 kV Supply System One-line

The substations supply thirteen (13) 13.2kV circuits, refer to *Figure 3, Salem Area 13.2kV Supply System One-line*:

1. Baron Ave: 10L1, 10L2, 10L4
2. Olde Trolley: 18L1, 18L2, 18L3, 18L4
3. Salem Depot: 9L1, 9L2, 9L3
4. Spicket River: 13L1, 13L2, 13L3

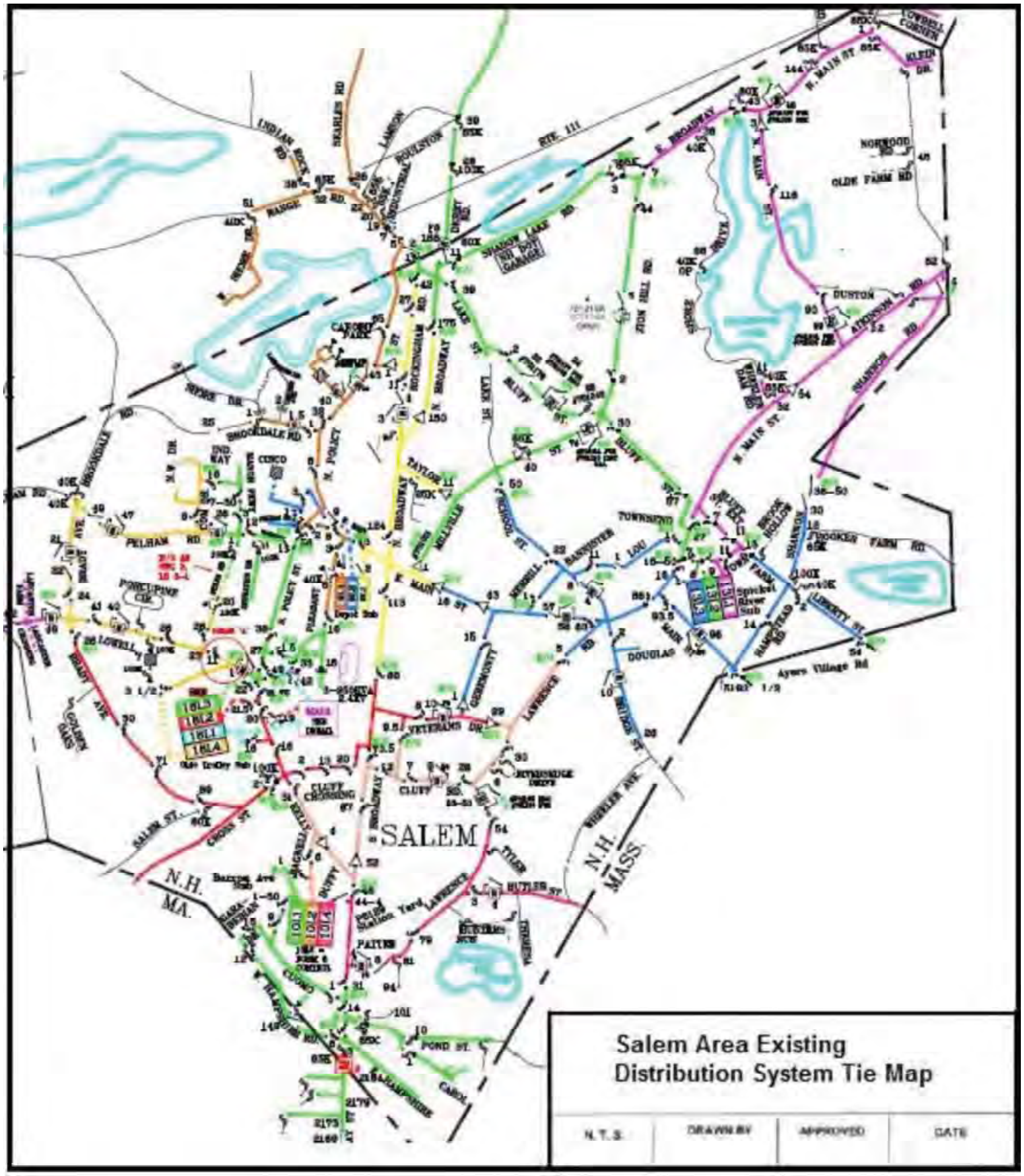


Figure 3 Salem Area 13.2kV Supply System One-line

3.3 Asset Conditions

Existing distribution asset concerns were taken into consideration during this study. The evaluation included the following:

1. Site visits to all Salem area Stations.
2. Review of condition assessment reports provided to Liberty Utilities by National Grid and most recently by United Power Group, INC. See Appendix D for a list of Condition Assessment Reports.

The following is a list of concerns that were documented as part of the Asset Condition evaluation:

1. Barron Ave No. 10 Substation was initially constructed in the early 1960s. It is supplied by the 2393 supply line, which originates from Golden Rock Station, and the National Grid 2353 supply line, which originates from the Methuen No 5 Station. Liberty Utilities has experienced multiple issues with asset concerns at this substation. The 10L1 recloser is 30 years old with an outdated control system (Form 3), the McGraw Edison type VSA has a high failure rate. The 10L4 recloser is 30 years old, this model Kyle recloser is no longer supported with spare parts and the control system has a high failure rate. The regulator contacts are at end of its useful life and the height to live parts inside the substation is below minimum height clearance requirements for a modern substation. It is not considered practical or economic to rebuild the substation in its present location, based upon a benchmark cost of approximately $1 million per feeder position, plus site and supply side construction. Further, capacity is limited to what the Salem 23kV system can provide.

   Additionally, per the 2014 United Power Group, Inc. Asset Condition Report:

   a. The 10L1 – Transformer bushings are showing signs of deterioration; the transformer is over 50 years old.
   b. The 10L2 – 20 Amp Control Circuit Breaker needs replacement.
   c. The 10L4 – Transformer bushings are showing signs of deterioration and are leaking oil around the bottom valve.

2. Salem Depot No. 9 Substation was initially constructed in the 1950's. It is supplied by the 2393 supply line and the 2352 supply line, which originate from Golden Rock Station. The existing 9L1 and 9L2 Breaker Positions and bus are constructed on Wood Pole Structures with limited clearance. This causes reliability and maintenance concerns at the station. It is not considered practical or economic to rebuild the substation in its present

location, based upon a benchmark cost of approximately $1 million per feeder position, plus site and supply side construction. Further, capacity is limited to what the Salem 23kV system can provide.

Additionally, per the 2014 United Power Group, Inc. Asset Condition Report:

a. The 9L3 Transformer 9T3's H3 bushing is showing signs of deterioration.

3. Per the National Grid Asset Condition Report (08/26/2006);
   a. The Olde Trolley 18L2 A and C phase regulator tanks are severely rusted. The regulators will require replacement with 10 years.

3.4 Present Loading and Load Growth

The study was conducted using load data beginning with the recorded 2016 peak load; refer to Table 1 Salem 2016 Peak Load.

Station	*Circuit*	*2016 Peak Load (Amps)*
BARRON AVENUE 10	10L1	197
BARRON AVENUE 10	10L2	312
BARRON AVENUE 10	10L4	229
OLDE TROLLEY 18	18L1	280
OLDE TROLLEY 18	18L2	366
OLDE TROLLEY 18	18L3	321
OLDE TROLLEY 18	18L4	328
SALEM DEPOT 9	9L1	135
SALEM DEPOT 9	9L2	284
SALEM DEPOT 9	9L3	346
SPICKET RIVER 13	13L1	304
SPICKET RIVER 13	13L2	424
SPICKET RIVER 13	13L3	362
Golden Rock	2352	816
Golden Rock	2393	946

Table 1 Salem Area 2016 Peak Load

Anticipated large customer spot loads were also added to the evaluation, refer to Table 2 Spot Loads. The Distribution System was modelled and analyzed using the CYME application to perform the load flow analysis.

Year	*Distribution Circuit*	*Location*	*Load (Amps)*
2017	9L1	Rockingham Park North	104
2017	9L3	Rockingham Park North	32
2018	18L2	Rockingham Park South	13
2018	9L3	Windham Economic Development I	66
2018	9L3	Windham Economic Development II	66
2018	18L3	Rockingham Park South	186
2019	18L2	Rockingham Park South	88
2019	18L3	Rockingham Park South	110
2019	9L1	Rockingham Park South	50
2019	9L2	Rockingham Park South	35

Table 2 Salem Area Spot Loads

The load was escalated through 2031 using the Summer Township Normal – Salem NH load growth data provided by Liberty Utilities; refer to Table 3 Summer Township Normal Load Growth - Salem, NH.

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Summer Township Normal - Salem NH

PSA	Town	Year	MW	% Increase
Eastern Geco	Salem, NH	2016	71.96	
Eastern Geco	Salem, NH	2017	72.46	0.69%
Eastern Geco	Salem, NH	2018	73.04	0.80%
Eastern Geco	Salem, NH	2019	73.58	0.75%
Eastern Geco	Salem, NH	2020	73.95	0.50%
Eastern Geco	Salem, NH	2021	74.23	0.38%
Eastern Geco	Salem, NH	2022	74.54	0.43%
Eastern Geco	Salem, NH	2023	74.91	0.49%
Eastern Geco	Salem, NH	2024	75.25	0.46%
Eastern Geco	Salem, NH	2025	75.57	0.43%
Eastern Geco	Salem, NH	2026	75.90	0.44%
Eastern Geco	Salem, NH	2027	76.24	0.45%
Eastern Geco	Salem, NH	2028	76.60	0.47%
Eastern Geco	Salem, NH	2029	76.97	0.49%
Eastern Geco	Salem, NH	2030	77.36	0.50%
Eastern Geco	Salem, NH	2031	77.76	0.50%

Table 3 Summer Township Normal Load Growth - Salem, NH

Liberty Utilities New Hampshire

Final Seasonal Peak Forecasts 2018-2034

Prepared By

Business Economic Analysis and Research

January 2019

Summary of Results

The weather adjusted actual seasonal peaks appear in Table 1 below for Liberty Utilities New Hampshire (LUNH). Note that the peak load series reflects the historic impacts of both energy efficiency programs and distributed generation activities in the LUNH service territory. Since the forecast is based on normal weather conditions, weather adjusting actual peaks enhances comparisons between historic and forecasted peaks.

Table 1
Historic Weather Adjusted Peaks

year	Summer month	Wthr Adj Peak Mw	Growth	Winter month	Wthr Adj Peak Mw	Growth
2004	7	184.555		12	151.111	
2005	7	193.986	5.11%	12	162.349	7.44%
2006	7	186.673	-3.77%	1	152.805	-5.88%
2007	7	187.153	0.26%	12	152.433	-0.24%
2008	7	194.86	4.12%	12	146.156	-4.12%
2009	7	190.024	-2.48%	12	153.679	5.15%
2010	7	188.816	-0.64%	12	148.528	-3.35%
2011	8	200.696	6.29%	2	151.769	2.18%
2012	8	189.021	-5.82%	1	152.708	0.62%
2013	7	194.125	2.70%	12	155.566	1.87%
2014	7	200.63	3.35%	1	158.976	2.19%
2015	7	184.56	-8.01%	1	148.31	-6.71%
2016	7	187.134	1.39%	1	144.578	-2.52%
2017	8	185.065	-1.11%	12	144.559	-0.01%
2013-2017 Avg			-0.42%			-1.07%

The summer peak has dropped .42% per year over the past five years compared to the winter peak declining 1.07% annually over the same period.

Table 2 displays the LUNH 2018-2034 seasonal peak forecasts under normal peak day weather conditions. The forecasted peak values include the historic impacts from both energy efficiency programs and distributed generation activities in the LUNH service territory. The 2018 growth is based on the 2017 weather adjusted actual shown in Table 1.

Table 2
Forecasted Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	193.324	4.46%	12	149.036	3.10%
2019	7	194.168	0.44%	12	149.322	0.19%
2020	7	194.898	0.38%	12	149.483	0.11%
2021	7	195.572	0.35%	12	149.636	0.10%
2022	7	196.27	0.36%	12	149.836	0.13%
2023	7	196.994	0.37%	12	150.047	0.14%
2024	7	197.702	0.36%	12	150.223	0.12%
2025	7	198.396	0.35%	12	150.4	0.12%
2026	7	199.093	0.35%	12	150.583	0.12%
2027	7	199.797	0.35%	12	150.771	0.12%
2028	7	200.508	0.36%	12	150.969	0.13%
2029	7	201.228	0.36%	12	151.175	0.14%
2030	7	201.957	0.36%	12	151.39	0.14%
2031	7	202.693	0.36%	12	151.61	0.15%
2032	7	203.433	0.37%	12	151.834	0.15%
2033	7	204.177	0.37%	12	152.063	0.15%
2034	7	204.927	0.37%	12	152.298	0.15%
2020-2024 Avg			0.36%			0.12%

The average annual summer growth rate in peak for 2020-2024 is .36% while the winter average annual growth rate is .12% over the same period.

Table 3 provides the LUNH 2018-2034 seasonal peak forecasts under extreme weather. Although the peaks are higher, the annual growth rates for 2020-2024 are just less than the growth rates using normal weather.

Table 3
Forecasted Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	212.317		12	155.069	
2019	7	213.19	0.41%	12	155.355	0.18%
2020	7	213.95	0.36%	12	155.516	0.10%
2021	7	214.653	0.33%	12	155.669	0.10%
2022	7	215.38	0.34%	12	155.87	0.13%
2023	7	216.133	0.35%	12	156.08	0.13%
2024	7	216.87	0.34%	12	156.256	0.11%
2025	7	217.593	0.33%	12	156.433	0.11%
2026	7	218.32	0.33%	12	156.616	0.12%
2027	7	219.052	0.34%	12	156.804	0.12%
2028	7	219.793	0.34%	12	157.002	0.13%
2029	7	220.542	0.34%	12	157.208	0.13%
2030	7	221.299	0.34%	12	157.423	0.14%
2031	7	222.064	0.35%	12	157.644	0.14%
2032	7	222.833	0.35%	12	157.867	0.14%
2033	7	223.607	0.35%	12	158.096	0.15%
2034	7	224.386	0.35%	12	158.331	0.15%
2020-2024 Avg			0.35%			0.12%

In previous peak day studies performed by National Grid, Eastern PSA and Western PSA hourly data was the source of historic peak day analysis and subsequent forecasts. In this study, LUNH system hourly data was the only source of historic peak day analysis. Once the LUNH system seasonal peak day forecasts were developed in this analysis, Eastern PSA and Western PSA forecasts were derived by using the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018. Table 4 below reveals the Eastern PSA seasonal forecasts under normal weather conditions.

Table 4
Eastern PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	97.8993		12	71.0305	
2019	7	98.3267	0.44%	12	71.1669	0.19%
2020	7	98.6964	0.38%	12	71.2435	0.11%
2021	7	99.0377	0.35%	12	71.3165	0.10%
2022	7	99.391	0.36%	12	71.4118	0.13%
2023	7	99.7577	0.37%	12	71.5125	0.14%
2024	7	100.1162	0.36%	12	71.5963	0.12%
2025	7	100.4677	0.35%	12	71.6807	0.12%
2026	7	100.8208	0.35%	12	71.7679	0.12%
2027	7	101.1773	0.35%	12	71.8575	0.12%
2028	7	101.5373	0.36%	12	71.9518	0.13%
2029	7	101.9018	0.36%	12	72.05	0.14%
2030	7	102.271	0.36%	12	72.1524	0.14%
2031	7	102.6437	0.36%	12	72.2574	0.15%
2032	7	103.0185	0.37%	12	72.3641	0.15%
2033	7	103.3952	0.37%	12	72.4733	0.15%
2034	7	103.775	0.37%	12	72.5852	0.15%
2020-2024 Avg			0.36%			0.12%

Table 5 lists the Western PSA seasonal forecasts under normal weather conditions. The Eastern PSA numbers are slightly higher than the Western peak day values in the summer but somewhat lower in the winter months.

Table 5
Western PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	95.4248		12	78.0054	
2019	7	95.8414	0.44%	12	78.1554	0.19%
2020	7	96.2016	0.38%	12	78.2394	0.11%
2021	7	96.5343	0.35%	12	78.3194	0.10%
2022	7	96.8789	0.36%	12	78.4242	0.13%
2023	7	97.2362	0.37%	12	78.5347	0.14%
2024	7	97.5858	0.36%	12	78.6266	0.12%
2025	7	97.9284	0.35%	12	78.7195	0.12%
2026	7	98.2723	0.35%	12	78.8148	0.12%
2027	7	98.6199	0.35%	12	78.9135	0.13%
2028	7	98.9709	0.36%	12	79.0173	0.13%
2029	7	99.3262	0.36%	12	79.1251	0.14%
2030	7	99.6859	0.36%	12	79.2376	0.14%
2031	7	100.0491	0.36%	12	79.3526	0.15%
2032	7	100.4148	0.37%	12	79.4698	0.15%
2033	7	100.7816	0.37%	12	79.5897	0.15%
2034	7	101.1519	0.37%	12	79.7129	0.15%
2020-2024 Avg			0.36%			0.12%

Tables 6 and 7 provide the Eastern PSA and Western PSA seasonal forecasts under extreme weather conditions. As the case with the normal weather forecasts, The Eastern PSA values are higher than the Western PSA numbers in the summer but lower during the winter period.

Table 6
Eastern PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	107.5173		12	73.9059	
2019	7	107.9595	0.41%	12	74.0422	0.18%
2020	7	108.3443	0.36%	12	74.119	0.10%
2021	7	108.7002	0.33%	12	74.1918	0.10%
2022	7	109.0684	0.34%	12	74.2877	0.13%
2023	7	109.4498	0.35%	12	74.3876	0.13%
2024	7	109.823	0.34%	12	74.4716	0.11%
2025	7	110.189	0.33%	12	74.556	0.11%
2026	7	110.5572	0.33%	12	74.6433	0.12%
2027	7	110.9279	0.34%	12	74.7328	0.12%
2028	7	111.3032	0.34%	12	74.8272	0.13%
2029	7	111.6825	0.34%	12	74.9254	0.13%
2030	7	112.0658	0.34%	12	75.0278	0.14%
2031	7	112.4532	0.35%	12	75.1331	0.14%
2032	7	112.8427	0.35%	12	75.2394	0.14%
2033	7	113.2346	0.35%	12	75.3486	0.15%
2034	7	113.629	0.35%	12	75.4606	0.15%
2020-2024 Avg			0.35%			0.12%

Table 7
Western PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	104.7997		12	81.1631	
2019	7	105.2306	0.41%	12	81.3128	0.18%
2020	7	105.6058	0.36%	12	81.3971	0.10%
2021	7	105.9527	0.33%	12	81.4771	0.10%
2022	7	106.3115	0.34%	12	81.5821	0.13%
2023	7	106.6833	0.35%	12	81.6922	0.13%
2024	7	107.047	0.34%	12	81.7843	0.11%
2025	7	107.4041	0.33%	12	81.8771	0.11%
2026	7	107.7628	0.33%	12	81.9728	0.12%
2027	7	108.1243	0.34%	12	82.0713	0.12%
2028	7	108.4899	0.34%	12	82.175	0.13%
2029	7	108.8596	0.34%	12	82.2826	0.13%
2030	7	109.2332	0.34%	12	82.3951	0.14%
2031	7	109.6111	0.35%	12	82.5109	0.14%
2032	7	109.9904	0.35%	12	82.6275	0.14%
2033	7	110.3723	0.35%	12	82.7473	0.14%
2034	7	110.7569	0.35%	12	82.8704	0.15%
2020-2024 Avg			0.35%			0.12%

The report describes the analytical approach employed in developing the seasonal LUNH forecasts and details the data available for the analysis.

Introduction

This report presents the Liberty Utilities New Hampshire (LUNH) seasonal peak forecasts for 2018-2034 under both normal and extreme weather. Regression analysis was used to estimate the LUNH historic monthly peak day model. The historic monthly peaks were net of all energy efficiency and distributed generation load impacts. The monthly peak day model coefficients were then employed to develop seasonal peak forecasts at the LUNH system level. The LUNH system seasonal peak forecasts were then split into Eastern and Western jurisdictions using LUNH township sales information as well the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018.

The remainder of this report is organized as follows. First, the data used in the analysis is described. Second, the regression model specifications are provided. Third, the results from the regression models are discussed. Finally, the 2018-2034 seasonal forecast process is detailed.

Data

There were three data sources employed to perform the historic peak day modeling. These sources include LUNH hourly load and annual township sales, economic drivers for the LUNH service area, and daily weather information.

Hourly system load for LUNH from October 2000 through April 2014 was supplied by National Grid while historic system loads from May 2014 through October 2018 was provided by LUNH staff. LUNH also supplied hourly Eastern and Western PSA loads for March 2014 through October 2018. The historic peak load data includes the impacts of energy efficiency programs as well as distributed generation activities. Also, National Grid supplied annual sales data for 21 townships from 1996 through 2013 and 2014-2017 township volumes came from LUNH. The 2014-2017 township volumes collapsed 2 small townships into larger ones so the 1996 through 2013 data was aggregated as well down to 19 townships.

The system load and annual township sales information was utilized to create the dependent variables for the various regression models estimated. For the monthly peak day analysis, the maximum hourly load for each month from October 2000 through October 2018 was identified as the dependent variable (LUNH staff requested not using 2002-2003 peak day values). A total of 193 months of peaks are used in the peak day analysis. Each of the 19 townships has 22 years of annual sales in the annual usage analysis. Appendix A contains the historic monthly peak values for LUNH.

Annual employment and number of households for Rockingham and Grafton counties from 1970 through 2043 was purchased from Moody's Economy.com to develop an economic variable for the monthly peak model. Employment and household values were summed across the two counties. Each series was then divided by the 2017 employment and household value to create annual ratios. The annual ratios were then combined using a 60% weight for employment and 40% weight for households based on previous work performed by National Grid. The annual ratios were converted to monthly numbers over the historic and forecast period by spreading the annual growth rate into 12 equal parts. Appendix B reveals the annual total employment and total households for Rockingham and Grafton counties from 2000 to 2034 along with the development of the annual employment/household ratio term.

Weather information came from NOAA. Daily high temperature, low temperature, and dew point temperature information from the Concord New Hampshire Airport (WBAN #14745) was obtained for March 1994 through October 2018. Using the above mentioned weather elements, the temperature humidity index (THI) and heating degree days (HDD) were used in the peak day modeling analysis while annual cooling degree days (CDD) was used when modeling annual township sales. The discussion of how each specific weather element is computed resides in the model specification section of this report.

Specification of Models

This section first provides the specification of the peak day model followed by a description of the annual township sales models.

Peak Day Model Specification

The monthly peak day usage was primarily driven by weather conditions. The most important weather term was the temperature humidity index (THI). The daily THI was defined as follows:

THI = .55 * maximum temperature + .2 * average dew point temperature + 17.5

A weighted THI variable (WTHI) was used in the model to account for the heat buildup impact on energy usage. The WTHI equaled:

WTHI = .7 * THI on the peak day + .2 * THI day before + .1 * THI two days before

In addition to the WTHI term, a summer period (June through September) indicator was interacted with the WTHI as follows:

WTHI_SUMMER = WTHI * summer period

To account for the increased saturation of air conditioning in the service territory, the WTHI_SUMMER term defined above was also interacted with a time trend term (the value of the trend started at 1 in year 2000 and increased to 19 in year 2018) as described below:

WTHI_SUMMER_T = WTHI_SUMMER * time trend

The coefficient values of three THI terms defined above are expected to be positive in the regression model based on the assumption that the higher the WTHI value, the higher the peak day value will be. To account for peaks during the winter period, a heating degree day (HDD) term was added based on the maximum daily temperature on the peak day, the day before the peak, and two days prior to the peak (WTMAX). WTMAX equaled:

WTMAX = .7*max temp on peak day + 2*max temp day before +.1*max temp 2 days before

The term HDD was defined as

HDD = (55 – WTMAX), or 0 if the value of WTMAX was greater than or equal to 55

The expected value of the HDD coefficient in the regression equation is greater than zero which suggests the peak day use rises as the temperature becomes colder. The economic variable included in the peak day model was the weighted employment and household (EMP_HH) index variable discussed in the previous section of this report. EMP_HH was defined as

EMP_HH = .6 * employment index + .4 * household index

The index portion of this variable was computed by dividing the actual employment and household count variables by the 2017 values. It is expected that a positive relationship exists between peak day use and the value of the index. The remaining variables included in the peak day model were monthly indicators. These indicators take the value of one for a particular month, zero otherwise. The monthly indicators included are as follows:

FEB = one if month is February, zero otherwise

MAR = one if month is March, zero otherwise

APR = one if month is April, zero otherwise

MAY = one if month is May, zero otherwise

JUN = one if month is June, zero otherwise

JUL = one if month is July, zero otherwise

AUG = one if month is August, zero otherwise

SEP = one if month is September, zero otherwise

OCT = one if month is October, zero otherwise

NOV = one if month is November, zero otherwise

DEC = one if month is December, zero otherwise

The final LUNH peak day model expressed in mathematical terms is as follows:

PeakDay Mw = a + b * WTHI + c * WTHI_SUMMER + d * WTHI_SUMMER_T
+ e * HDD + f * EMP_HH + g * FEB + h * MAR + i * APR + j * MAY
+ k * JUN + l * JUL + m * AUG + n * SEP + o * OCT + p * NOV
+ q * DEC

Values of the estimated coefficients (a, b …, q) will be presented and discussed in the next section of the report.

Annual Township Sales Model Specification

The principal factor that influences annual sales at the township level has been a time trend that takes the value of one in 1996 and increases to twenty two in 2017. In order to flatten the change in township usage over the historic period, the time trend variable was expressed as a log function. The trend term variable was expressed as follows:

TIME = log(time trend value + 1)

The value of TIME is expected to have a positive coefficient value if the township experienced sales growth from 1996 through 2017 and a negative value if township sales declined from 1996 through 2017. The other term included in the annual township sales models was annual cooling degree days (CDD). CDD was based on the average daily temperature (daily maximum temperature plus daily minimum temperature divided by two). Daily cooling degree days was defined as:

CDD = (average temp – 60), or 0 if the average temp was less than or equal to 60.

The daily CDD values were then summed for the entire calendar year for final inclusion into the township models. It was expected that a positive relationship existed between CDD and annual sales. Township regression models that generated a negative coefficient for CDD had that variable removed from the analysis. The final LUNH annual township models expressed in mathematical terms are as follows:

Annual kWh = a + b * TIME + c * CDD

Values of the estimated coefficients (a, b, and c) will be presented and discussed in the next section of the report.

Regression Results

This section provides the overall model statistics as well as estimated coefficient values for the peak day and annual township models. The peak day model adjusted R-Squared value was .8750 which means that almost 88% of the monthly historic peak day variation was explained by the model coefficients. The monthly peak day Mw model coefficients are as follows:

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|
INTERCEPT	64.86846	23.20202	2.8	0.0058
WTHI	0.85693	0.20588	4.16	<.0001
WTHI_SUMMER	3.1535	0.46812	6.74	<.0001
WTHI_SUMMER_T	0.00632	0.00306	2.06	0.0406
HDD	0.96711	0.23931	4.04	<.0001
EMP_HH	24.462	21.59604	1.13	0.2589
FEB	-4.66736	2.84739	-1.64	0.103
MAR	-8.22188	3.20446	-2.57	0.0111
APR	-17.97462	4.53312	-3.97	0.0001
MAY	-2.41446	5.41104	-0.45	0.656
JUN	-239.189	36.00799	-6.64	<.0001
JUL	-234.42314	36.64564	-6.4	<.0001
AUG	-234.567	36.24369	-6.47	<.0001
SEP	-241.3816	35.23254	-6.85	<.0001
OCT	-13.51145	4.82839	-2.8	0.0057
NOV	-5.35602	4.05034	-1.32	0.1878
DEC	2.16819	2.96977	0.73	0.4663

The values of the WTHI terms have the expected positive coefficient signs and significant. The HDD term also has a significant expected positive coefficient sign. Likewise, the EMP_HH term has an insignificant expected positive coefficient sign and the coefficient value is smaller than in previous models. Only the MAY, NOV and DEC monthly terms are not significant at the 80% level. The JUN through SEP indicators have large negative values to offset the impact of the WTHI_SUMMER and WTHI_SUMMER_T terms.

The Eastern area annual kWh models by township appear as follows:

Eastern Township Regression Results

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Derry					R-Square	0.1887
INTERCEPT	-1835369	2055463	-0.89	0.3831		
TIME	693431	390994	1.77	0.0922		
CDD	2451.71302	2090.285	1.17	0.2553		
Town=Pelham					R-Square	0.843
INTERCEPT	23190627	7417272	3.13	0.0056		
TIME	12696638	1410926	9	<.0001		
CDD	16722	7542.929	2.22	0.039		
Town=Salem, NH					R-Square	0.3481
Intercept	260455731	18672477	13.95	<.0001		
TIME	4661243	3489929	1.34	0.1983		
CDD	23524	19167	1.23	0.2355		
YEAR 2005	27801238	10711572	2.6	0.0183		
Town=Windham					R-Square	0.7684
INTERCEPT	8359128	1308965	6.39	<.0001		
TIME	1749608	248994	7.03	<.0001		
CDD	2533.59809	1331.141	1.9	0.0723		

Note that the Salem Township had a year 2005 indicator variable added to capture a spike in annual usage for that year. All the CDD terms were significant at the 75% confidence level which is reasonable for a twenty two year historic series.

Western area annual kWh models by township are displayed below. The Grafton Township had a year 2002 indicator variable to capture a spike in usage for that year and Monroe Township had inserted a year 2015 indicator variable to capture a sharp decline in usage for that year.

Western Township Regression Results #1

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Acworth					R-Square	0.2872
INTERCEPT	1138893	40922	27.83	<.0001		
TIME	51619	16782	3.08	0.006		
Town=Alstead					R-Square	0.2703
INTERCEPT	9911652	279550	35.46	<.0001		
TIME	339631	114640	2.96	0.0077		
Town=Bath					R-Square	0.6263
INTERCEPT	-24230	18148	-1.34	0.1976		
TIME	16396	3452.176	4.75	0.0001		
CDD	34.64262	18.45562	1.88	0.0759		
Town=Canaan					R-Square	0.5829
INTERCEPT	10109160	992313	10.19	<.0001		
TIME	939189	188760	4.98	<.0001		
CDD	626.87929	1009.124	0.62	0.5418		
Town=Charlestown, NH					R-Square	0.662
INTERCEPT	1341700	7090630	0.19	0.8519		
TIME	7708582	1348792	5.72	<.0001		
CDD	7084.15717	7210.754	0.98	0.3382		
Town=Cornish					R-Square	0.2728
INTERCEPT	737101	125034	5.9	<.0001		
TIME	60214	23784	2.53	0.0203		
CDD	106.30368	127.1522	0.84	0.4135		

Western Township Regression Results #2

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Enfield					R-Square	0.696
INTERCEPT	14777186	1182050	12.5	<.0001		
TIME	1424926	224852	6.34	<.0001		
CDD	816.14872	1202.076	0.68	0.5054		
Town=Grafton, NH					R-Square	0.2885
INTERCEPT	58659	6089.404	9.63	<.0001		
TIME	1831.8423	2481.113	0.74	0.4693		
YEAR 2002	25472	7934.861	3.21	0.0046		
Town=Hanover, NH					R-Square	0.7912
INTERCEPT	71690818	10136017	7.07	<.0001		
TIME	15531554	1928091	8.06	<.0001		
CDD	9687.25295	10308	0.94	0.3591		
Town=Lebanon					R-Square	0.8205
INTERCEPT	75964275	26385845	2.88	0.0096		
TIME	41806548	5019161	8.33	<.0001		
CDD	54227	26833	2.02	0.0576		
Town=Marlow					R-Square	0.1333
INTERCEPT	27954	7196.082	3.88	0.001		
TIME	2734.8391	1368.851	2	0.0602		
CDD	2.38771	7.31799	0.33	0.7478		

Variable	Western Township Regression Results #3 Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Monroe, NH					R-Square	0.0412
INTERCEPT	1749590	49783	35.14	<.0001		
TIME	10203	20693	0.49	0.6276		
YEAR 2015	-112537	66177	-1.7	0.1053		
Town=Plainfield					R-Square	0.4926
INTERCEPT	4730329	569497	8.31	<.0001		
TIME	417108	108331	3.85	0.0011		
CDD	691.89342	579.1449	1.19	0.2469		
Town=Surry					R-Square	0.5655
INTERCEPT	126126	47772	2.64	0.0161		
TIME	44633	9087.18	4.91	<.0001		
CDD	18.33472	48.58082	0.38	0.7101		
Town=Walpole					R-Square	0.4369
INTERCEPT	22018299	1526600	14.42	<.0001		
TIME	1065108	290392	3.67	0.0016		
CDD	1156.39317	1552.462	0.74	0.4655		

Except for Grafton, all the western area townships had significant time trend coefficients at the 90% confidence level. All of the larger usage Western Townships had CDD coefficients significant at the 70% confidence level.

An explanation of how the peak day and township model coefficients are employed to generate seasonal peak day forecasts appears in the next section.

Seasonal Forecast Development for 2018-2034

The peak day model coefficients detailed in the previous section of the report are used along with the economic driver forecast (shown in Appendix B) and normal/extreme weather to estimate seasonal peak forecasts for 2018 through 2034. The normal monthly WTHI and HDD values were computed by taking the average values for those terms during the October 2000 through September 2018 LUNH system monthly peak days. The extreme monthly WTHI and HDD values were extracted by taking the maximum values for those monthly terms during the October 2000 through September 2018 LUNH system monthly peak days. The normal and extreme monthly WTHI and HDD values appear below.

	Weather Values Used in Forecast			
Month	Normal WTHI	Extreme WTHI	Normal HDD	Extreme HDD
January	30.315	21.9	34.7444	45
February	34.0047	26.995	29.9167	38.1
March	39.7611	30.86	22.3111	32.6
April	62.9111	78.18	5.0389	25.1
May	75.9147	81.925	0	0
June	80.3658	84.525	0	0
July	81.8786	86.475	0	0
August	80.9872	84.61	0	0
September	78.1219	82.16	0	0
October	67.4789	75.035	1.3737	10.7
November	48.2356	37.26	12.0667	23.8
December	37.5533	21.37	25.8222	46.4

The normal and extreme LUNH system seasonal peak day forecasts appear in Tables 2 and 3 in the Summary of Results section of the report. The system peak day values were allocated to the Eastern and Western PSA regions by using the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018. The summer Eastern coincident peak proportion was 50.64% while the Western proportion was 49.36%. The winter Eastern coincident peak contribution was 46.66% compared to the Western value of 53.34%. Appendix C lists the Eastern and Western coincident peak contributions for March 2014 through October 2018.

The individual township peaks were then calculated by utilizing the annual township sales regression models. For townships with CDD in the model, normal CDD value equaled 1057 and the extreme CDD took the value of 1265 which were computed based upon 1998 through 2017 Concord weather data. Once the annual township forecasts were completed, they were totaled so that individual township annual proportions under normal and extreme weather could be applied to the area peak values.

The Derry township results are shown below. The annual growth rates for 2020-2024 are much larger than the overall system average.

			Derry Township Peaks					
	Summer		Winter		Summer		Winter	
	Normal		Normal		Extreme		Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	0.7228		0.5244		0.9092		0.625	
2019	0.7314	1.19%	0.5294	0.95%	0.9186	1.03%	0.63	0.80%
2020	0.7394	1.09%	0.5337	0.81%	0.9273	0.95%	0.6344	0.70%
2021	0.747	1.03%	0.5379	0.79%	0.9355	0.88%	0.6385	0.65%
2022	0.7545	1.00%	0.5421	0.78%	0.9437	0.88%	0.6428	0.67%
2023	0.762	0.99%	0.5463	0.77%	0.9519	0.87%	0.6469	0.64%
2024	0.7693	0.96%	0.5502	0.71%	0.9598	0.83%	0.6508	0.60%
2025	0.7764	0.92%	0.5539	0.67%	0.9675	0.80%	0.6546	0.58%
2026	0.7834	0.90%	0.5576	0.67%	0.9751	0.79%	0.6584	0.58%
2027	0.7903	0.88%	0.5613	0.66%	0.9827	0.78%	0.662	0.55%
2028	0.7971	0.86%	0.5648	0.62%	0.9901	0.75%	0.6656	0.54%
2029	0.8038	0.84%	0.5684	0.64%	0.9975	0.75%	0.6692	0.54%
2030	0.8105	0.83%	0.5718	0.60%	1.0048	0.73%	0.6727	0.52%
2031	0.8172	0.83%	0.5753	0.61%	1.0121	0.73%	0.6762	0.52%
2032	0.8238	0.81%	0.5786	0.57%	1.0193	0.71%	0.6796	0.50%
2033	0.8303	0.79%	0.582	0.59%	1.0264	0.70%	0.683	0.50%
2034	0.8367	0.77%	0.5853	0.57%	1.0335	0.69%	0.6864	0.50%
2020-2024 Avg		1.04%		0.79%		0.90%		0.66%

The Pelham township results are provided next. The 2020-2024 annual growth rates for Pelham are not as large as Derry but larger than the overall system.

Pelham Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	19.8326		14.3895		22.193		15.2552	
2019	20.006	0.87%	14.4799	0.63%	22.3766	0.83%	15.3466	0.60%
2020	20.1645	0.79%	14.5557	0.52%	22.545	0.75%	15.4232	0.50%
2021	20.3145	0.74%	14.6283	0.50%	22.7043	0.71%	15.4965	0.48%
2022	20.4642	0.74%	14.7034	0.51%	22.8634	0.70%	15.5725	0.49%
2023	20.6143	0.73%	14.7776	0.50%	23.0226	0.70%	15.6473	0.48%
2024	20.7604	0.71%	14.8464	0.47%	23.1777	0.67%	15.7169	0.44%
2025	20.903	0.69%	14.9137	0.45%	23.329	0.65%	15.7849	0.43%
2026	21.044	0.67%	14.9799	0.44%	23.4787	0.64%	15.8518	0.42%
2027	21.1839	0.66%	15.0451	0.44%	23.627	0.63%	15.9177	0.42%
2028	21.3228	0.66%	15.1099	0.43%	23.7745	0.62%	15.9832	0.41%
2029	21.4611	0.65%	15.1742	0.43%	23.9211	0.62%	16.0482	0.41%
2030	21.599	0.64%	15.2381	0.42%	24.067	0.61%	16.1128	0.40%
2031	21.7361	0.63%	15.3014	0.42%	24.2123	0.60%	16.1769	0.40%
2032	21.8725	0.63%	15.3641	0.41%	24.3567	0.60%	16.2402	0.39%
2033	22.008	0.62%	15.4262	0.40%	24.5003	0.59%	16.303	0.39%
2034	22.1431	0.61%	15.4879	0.40%	24.6432	0.58%	16.3654	0.38%
2020-2024 Avg		0.75%		0.51%		0.72%		0.48%

Salem forecasts are displayed next. The Salem annual growth rates are lower than the overall system rates and since Salem contributes the most to Eastern PSA total, Salem pushes down the Eastern PSA numbers that appear in Tables 4 through 7 in the Summary of Results section.

Salem Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	73.2909		53.176		79.9279		54.9413	
2019	73.5093	0.30%	53.2046	0.05%	80.1487	0.28%	54.9687	0.05%
2020	73.6882	0.24%	53.1915	-0.02%	80.3308	0.23%	54.9548	-0.03%
2021	73.8492	0.22%	53.1784	-0.02%	80.4952	0.20%	54.9409	-0.03%
2022	74.0223	0.23%	53.1845	0.01%	80.6718	0.22%	54.9464	0.01%
2023	74.2081	0.25%	53.1969	0.02%	80.8613	0.23%	54.9575	0.02%
2024	74.3905	0.25%	53.199	0.00%	81.0475	0.23%	54.9588	0.00%
2025	74.5701	0.24%	53.2035	0.01%	81.2311	0.23%	54.9625	0.01%
2026	74.7531	0.25%	53.212	0.02%	81.4187	0.23%	54.9702	0.01%
2027	74.9408	0.25%	53.224	0.02%	81.6104	0.24%	54.9814	0.02%
2028	75.1331	0.26%	53.2412	0.03%	81.8076	0.24%	54.9978	0.03%
2029	75.3306	0.26%	53.2627	0.04%	82.0097	0.25%	55.0185	0.04%
2030	75.5332	0.27%	53.2889	0.05%	82.2167	0.25%	55.0439	0.05%
2031	75.7401	0.27%	53.3182	0.05%	82.4283	0.26%	55.0727	0.05%
2032	75.9499	0.28%	53.3501	0.06%	82.6431	0.26%	55.1034	0.06%
2033	76.1627	0.28%	53.385	0.07%	82.8612	0.26%	55.1375	0.06%
2034	76.379	0.28%	53.4231	0.07%	83.0826	0.27%	55.1748	0.07%
2020-2024 Avg		0.24%		0.00%		0.22%		0.00%

The last Eastern PSA township, Windham, forecasts are displayed next. The annual growth rate in peaks for Windham from 2020-2024 are somewhat higher than the overall system average.

	Windham Township Peaks							
	Summer Normal		Winter Normal		Summer Extreme		Winter Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	4.053		2.9406		4.4872		3.0844	
2019	4.08	0.67%	2.953	0.42%	4.5156	0.63%	3.0969	0.41%
2020	4.1043	0.60%	2.9626	0.33%	4.5412	0.57%	3.1066	0.31%
2021	4.127	0.55%	2.9719	0.31%	4.5652	0.53%	3.1159	0.30%
2022	4.15	0.56%	2.9818	0.33%	4.5895	0.53%	3.126	0.32%
2023	4.1733	0.56%	2.9917	0.33%	4.614	0.53%	3.1359	0.32%
2024	4.196	0.54%	3.0007	0.30%	4.638	0.52%	3.1451	0.29%
2025	4.2182	0.53%	3.0096	0.30%	4.6614	0.50%	3.154	0.28%
2026	4.2403	0.52%	3.0184	0.29%	4.6847	0.50%	3.1629	0.28%
2027	4.2623	0.52%	3.0271	0.29%	4.7078	0.49%	3.1717	0.28%
2028	4.2843	0.52%	3.0359	0.29%	4.731	0.49%	3.1806	0.28%
2029	4.3063	0.51%	3.0447	0.29%	4.7542	0.49%	3.1895	0.28%
2030	4.3283	0.51%	3.0536	0.29%	4.7773	0.49%	3.1984	0.28%
2031	4.3503	0.51%	3.0625	0.29%	4.8005	0.49%	3.2073	0.28%
2032	4.3723	0.51%	3.0713	0.29%	4.8236	0.48%	3.2162	0.28%
2033	4.3942	0.50%	3.0801	0.29%	4.8467	0.48%	3.2251	0.28%
2034	4.4162	0.50%	3.0889	0.29%	4.8697	0.47%	3.234	0.28%
2020-2024 Avg		0.57%		0.32%		0.54%		0.31%

The Western Township forecasts are shown next starting with Acworth. The Acworth annual growth rates are much lower than the overall system for 2020-2024.

Acworth Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.242		0.1979		0.258		0.1998	
2019	0.2422	0.08%	0.1975	-0.20%	0.2581	0.04%	0.1995	-0.15%
2020	0.2422	0.00%	0.197	-0.25%	0.2581	0.00%	0.199	-0.25%
2021	0.2421	-0.04%	0.1965	-0.25%	0.2581	0.00%	0.1985	-0.25%
2022	0.2422	0.04%	0.1961	-0.20%	0.2581	0.00%	0.1981	-0.20%
2023	0.2423	0.04%	0.1957	-0.20%	0.2582	0.04%	0.1977	-0.20%
2024	0.2424	0.04%	0.1953	-0.20%	0.2583	0.04%	0.1974	-0.15%
2025	0.2425	0.04%	0.195	-0.15%	0.2585	0.08%	0.197	-0.20%
2026	0.2427	0.08%	0.1946	-0.21%	0.2586	0.04%	0.1967	-0.15%
2027	0.2429	0.08%	0.1943	-0.15%	0.2588	0.08%	0.1964	-0.15%
2028	0.2431	0.08%	0.1941	-0.10%	0.259	0.08%	0.1962	-0.10%
2029	0.2433	0.08%	0.1938	-0.15%	0.2592	0.08%	0.1959	-0.15%
2030	0.2436	0.12%	0.1936	-0.10%	0.2595	0.12%	0.1957	-0.10%
2031	0.2439	0.12%	0.1934	-0.10%	0.2598	0.12%	0.1955	-0.10%
2032	0.2442	0.12%	0.1932	-0.10%	0.2601	0.12%	0.1954	-0.05%
2033	0.2445	0.12%	0.1931	-0.05%	0.2604	0.12%	0.1952	-0.10%
2034	0.2449	0.16%	0.193	-0.05%	0.2608	0.15%	0.1951	-0.05%
2020-2024 Avg		0.02%		-0.22%		0.02%		-0.21%

Alstead township forecast appears next. As the case with Acworth, Alstead annual growth in peak is much lower than the system average.

Alstead Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	2.0418		1.6691		2.1768		1.6858	
2019	2.042	0.01%	1.6652	-0.23%	2.1768	0.00%	1.682	-0.23%
2020	2.0414	-0.03%	1.6603	-0.29%	2.1761	-0.03%	1.6772	-0.29%
2021	2.0406	-0.04%	1.6555	-0.29%	2.1751	-0.05%	1.6726	-0.27%
2022	2.0403	-0.01%	1.6516	-0.24%	2.1747	-0.02%	1.6688	-0.23%
2023	2.0405	0.01%	1.6481	-0.21%	2.1748	0.00%	1.6654	-0.20%
2024	2.0409	0.02%	1.6444	-0.22%	2.1751	0.01%	1.6618	-0.22%
2025	2.0413	0.02%	1.6409	-0.21%	2.1755	0.02%	1.6584	-0.20%
2026	2.042	0.03%	1.6377	-0.20%	2.1761	0.03%	1.6553	-0.19%
2027	2.043	0.05%	1.6348	-0.18%	2.177	0.04%	1.6524	-0.18%
2028	2.0442	0.06%	1.6321	-0.17%	2.1781	0.05%	1.6498	-0.16%
2029	2.0457	0.07%	1.6297	-0.15%	2.1796	0.07%	1.6474	-0.15%
2030	2.0475	0.09%	1.6275	-0.13%	2.1812	0.07%	1.6453	-0.13%
2031	2.0495	0.10%	1.6255	-0.12%	2.1832	0.09%	1.6434	-0.12%
2032	2.0517	0.11%	1.6237	-0.11%	2.1853	0.10%	1.6416	-0.11%
2033	2.054	0.11%	1.6221	-0.10%	2.1876	0.11%	1.64	-0.10%
2034	2.0565	0.12%	1.6206	-0.09%	2.19	0.11%	1.6386	-0.09%
2020-2024 Avg		-0.01%		-0.25%		-0.02%		-0.24%

The Bath township forecasts are displayed below. The annual growth in the Bath peaks from 2020-2024 is higher than the system average although the peaks are very small.

Bath Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.012		0.0098		0.0142		0.011	
2019	0.0121	0.83%	0.0099	1.02%	0.0143	0.70%	0.0111	0.91%
2020	0.0122	0.83%	0.0099	0.00%	0.0144	0.70%	0.0111	0.00%
2021	0.0123	0.82%	0.01	1.01%	0.0145	0.69%	0.0112	0.90%
2022	0.0124	0.81%	0.01	0.00%	0.0146	0.69%	0.0112	0.00%
2023	0.0125	0.81%	0.0101	1.00%	0.0147	0.68%	0.0113	0.89%
2024	0.0126	0.80%	0.0101	0.00%	0.0148	0.68%	0.0113	0.00%
2025	0.0127	0.79%	0.0102	0.99%	0.0149	0.68%	0.0114	0.88%
2026	0.0127	0.00%	0.0102	0.00%	0.015	0.67%	0.0114	0.00%
2027	0.0128	0.79%	0.0103	0.98%	0.0151	0.67%	0.0115	0.88%
2028	0.0129	0.78%	0.0103	0.00%	0.0152	0.66%	0.0115	0.00%
2029	0.013	0.78%	0.0104	0.97%	0.0153	0.66%	0.0115	0.00%
2030	0.0131	0.77%	0.0104	0.00%	0.0154	0.65%	0.0116	0.87%
2031	0.0132	0.76%	0.0104	0.00%	0.0154	0.00%	0.0116	0.00%
2032	0.0133	0.76%	0.0105	0.96%	0.0155	0.65%	0.0117	0.86%
2033	0.0133	0.00%	0.0105	0.00%	0.0156	0.65%	0.0117	0.00%
2034	0.0134	0.75%	0.0106	0.95%	0.0157	0.64%	0.0118	0.85%
2020-2024 Avg		0.83%		0.40%		0.70%		0.36%

Forecasts for the Canaan Township appear below. The annual growth rate in Canaan is less than the system average during the 2020-2024 years.

Canaan Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	2.5555		2.089		2.7503		2.13	
2019	2.5597	0.16%	2.0874	-0.08%	2.7545	0.15%	2.1284	-0.08%
2020	2.5627	0.12%	2.0842	-0.15%	2.7575	0.11%	2.1254	-0.14%
2021	2.5652	0.10%	2.0812	-0.14%	2.7601	0.09%	2.1225	-0.14%
2022	2.5683	0.12%	2.079	-0.11%	2.7632	0.11%	2.1204	-0.10%
2023	2.5719	0.14%	2.0773	-0.08%	2.7669	0.13%	2.1187	-0.08%
2024	2.5756	0.14%	2.0752	-0.10%	2.7706	0.13%	2.1167	-0.09%
2025	2.5792	0.14%	2.0733	-0.09%	2.7743	0.13%	2.1149	-0.09%
2026	2.5831	0.15%	2.0716	-0.08%	2.7782	0.14%	2.1133	-0.08%
2027	2.5872	0.16%	2.0702	-0.07%	2.7824	0.15%	2.112	-0.06%
2028	2.5915	0.17%	2.0691	-0.05%	2.7869	0.16%	2.1109	-0.05%
2029	2.5962	0.18%	2.0682	-0.04%	2.7916	0.17%	2.11	-0.04%
2030	2.601	0.18%	2.0675	-0.03%	2.7965	0.18%	2.1094	-0.03%
2031	2.6061	0.20%	2.067	-0.02%	2.8017	0.19%	2.109	-0.02%
2032	2.6114	0.20%	2.0667	-0.01%	2.807	0.19%	2.1087	-0.01%
2033	2.6168	0.21%	2.0665	-0.01%	2.8125	0.20%	2.1086	0.00%
2034	2.6224	0.21%	2.0666	0.00%	2.8182	0.20%	2.1086	0.00%
2020-2024 Avg		0.12%		-0.12%		0.12%		-0.11%

The Charlestown township forecasts are shown next below. The annual growth rate in peak forecasts is higher than the system average during the 2020-2024 years.

Charlestown Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	6.1913		5.0611		6.8924		5.3379	
2019	6.2426	0.83%	5.0906	0.58%	6.9461	0.78%	5.3673	0.55%
2020	6.2892	0.75%	5.1149	0.48%	6.9951	0.71%	5.3916	0.45%
2021	6.3331	0.70%	5.1381	0.45%	7.0412	0.66%	5.4147	0.43%
2022	6.3769	0.69%	5.1622	0.47%	7.0872	0.65%	5.4387	0.44%
2023	6.4208	0.69%	5.1858	0.46%	7.1333	0.65%	5.4623	0.43%
2024	6.4634	0.66%	5.2077	0.42%	7.178	0.63%	5.4841	0.40%
2025	6.5049	0.64%	5.2289	0.41%	7.2216	0.61%	5.5053	0.39%
2026	6.5458	0.63%	5.2498	0.40%	7.2647	0.60%	5.5261	0.38%
2027	6.5864	0.62%	5.2703	0.39%	7.3073	0.59%	5.5466	0.37%
2028	6.6268	0.61%	5.2907	0.39%	7.3497	0.58%	5.567	0.37%
2029	6.6669	0.61%	5.3109	0.38%	7.3918	0.57%	5.5872	0.36%
2030	6.7068	0.60%	5.3311	0.38%	7.4338	0.57%	5.6073	0.36%
2031	6.7466	0.59%	5.351	0.37%	7.4755	0.56%	5.6273	0.36%
2032	6.7861	0.59%	5.3706	0.37%	7.5169	0.55%	5.6469	0.35%
2033	6.8253	0.58%	5.3901	0.36%	7.5581	0.55%	5.6664	0.35%
2034	6.8644	0.57%	5.4095	0.36%	7.5991	0.54%	5.6858	0.34%
2020-2024 Avg		0.71%		0.46%		0.67%		0.44%

The Cornish township forecast numbers are displayed next. The annual growth in Cornish peaks is less than the 2020-2024 system average growth.

Cornish Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.1934		0.1581		0.2105		0.163	
2019	0.1936	0.10%	0.1579	-0.13%	0.2107	0.10%	0.1628	-0.12%
2020	0.1937	0.05%	0.1576	-0.19%	0.2109	0.09%	0.1625	-0.18%
2021	0.1938	0.05%	0.1573	-0.19%	0.211	0.05%	0.1622	-0.18%
2022	0.194	0.10%	0.1571	-0.13%	0.2111	0.05%	0.162	-0.12%
2023	0.1942	0.10%	0.1569	-0.13%	0.2113	0.09%	0.1618	-0.12%
2024	0.1944	0.10%	0.1566	-0.19%	0.2116	0.14%	0.1616	-0.12%
2025	0.1946	0.10%	0.1565	-0.06%	0.2118	0.09%	0.1614	-0.12%
2026	0.1949	0.15%	0.1563	-0.13%	0.212	0.09%	0.1613	-0.06%
2027	0.1951	0.10%	0.1561	-0.13%	0.2122	0.09%	0.1611	-0.12%
2028	0.1954	0.15%	0.156	-0.06%	0.2125	0.14%	0.161	-0.06%
2029	0.1957	0.15%	0.1559	-0.06%	0.2128	0.14%	0.1609	-0.06%
2030	0.196	0.15%	0.1558	-0.06%	0.2131	0.14%	0.1608	-0.06%
2031	0.1963	0.15%	0.1557	-0.06%	0.2135	0.19%	0.1607	-0.06%
2032	0.1967	0.20%	0.1556	-0.06%	0.2138	0.14%	0.1606	-0.06%
2033	0.197	0.15%	0.1556	0.00%	0.2142	0.19%	0.1606	0.00%
2034	0.1974	0.20%	0.1556	0.00%	0.2145	0.14%	0.1605	-0.06%
2020-2024 Avg		0.08%		-0.16%		0.09%		-0.15%

Enfield Township seasonal peak forecasts are listed next. Much like Cornish, the annual 2020-2024 growth in Enfield peaks is lower than the system average numbers.

	Enfield Township Peaks							
	Summer		Winter		Summer		Winter	
	Normal		Normal		Extreme		Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	3.7467		3.0627		4.0279		3.1195	
2019	3.7532	0.17%	3.0606	-0.07%	4.0345	0.16%	3.1175	-0.06%
2020	3.7579	0.13%	3.0562	-0.14%	4.0393	0.12%	3.1133	-0.13%
2021	3.7619	0.11%	3.0521	-0.13%	4.0434	0.10%	3.1093	-0.13%
2022	3.7667	0.13%	3.0492	-0.10%	4.0483	0.12%	3.1066	-0.09%
2023	3.7723	0.15%	3.0468	-0.08%	4.0541	0.14%	3.1044	-0.07%
2024	3.778	0.15%	3.044	-0.09%	4.0598	0.14%	3.1017	-0.09%
2025	3.7836	0.15%	3.0414	-0.09%	4.0656	0.14%	3.0993	-0.08%
2026	3.7895	0.16%	3.0392	-0.07%	4.0716	0.15%	3.0972	-0.07%
2027	3.7959	0.17%	3.0374	-0.06%	4.0781	0.16%	3.0954	-0.06%
2028	3.8025	0.17%	3.0359	-0.05%	4.0849	0.17%	3.0941	-0.04%
2029	3.8095	0.18%	3.0348	-0.04%	4.092	0.17%	3.093	-0.04%
2030	3.8169	0.19%	3.034	-0.03%	4.0995	0.18%	3.0923	-0.02%
2031	3.8246	0.20%	3.0334	-0.02%	4.1074	0.19%	3.0919	-0.01%
2032	3.8326	0.21%	3.0332	-0.01%	4.1154	0.19%	3.0916	-0.01%
2033	3.8407	0.21%	3.0331	0.00%	4.1238	0.20%	3.0916	0.00%
2034	3.8491	0.22%	3.0333	0.01%	4.1323	0.21%	3.0919	0.01%
2020-2024 Avg		0.13%		-0.11%		0.13%		-0.10%

Grafton Township forecast results are provided below. Annual growth in Grafton peaks is lower than the system average.

	Grafton Township Peaks							
year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.012		0.0098		0.0128		0.0099	
2019	0.012	0.00%	0.0098	0.00%	0.0128	0.00%	0.0099	0.00%
2020	0.012	0.00%	0.0097	-1.02%	0.0128	0.00%	0.0098	-1.01%
2021	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2022	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2023	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2024	0.012	0.00%	0.0096	-1.03%	0.0128	0.00%	0.0097	-1.02%
2025	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2026	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2027	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2028	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2029	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2030	0.012	0.00%	0.0095	-1.04%	0.0128	0.00%	0.0096	-1.03%
2031	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2032	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2033	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2034	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2020-2024 Avg		0.00%		-0.41%		0.00%		-0.40%

The Hanover township forecasts appear next. As one of the larger Western PSA townships, the Hanover annual growth rate from 2020-2024 is slightly lower than the system average growth.

	Hanover Township Peaks							
	Summer		Winter		Summer		Winter	
	Normal		Normal		Extreme		Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	24.3897		19.9375		26.401		20.4465	
2019	24.4794	0.37%	19.9621	0.12%	26.4937	0.35%	20.472	0.12%
2020	24.5554	0.31%	19.9706	0.04%	26.5731	0.30%	20.4816	0.05%
2021	24.6251	0.28%	19.9786	0.04%	26.646	0.27%	20.4907	0.04%
2022	24.6984	0.30%	19.9935	0.07%	26.7225	0.29%	20.5065	0.08%
2023	24.7754	0.31%	20.0103	0.08%	26.8027	0.30%	20.524	0.09%
2024	24.851	0.31%	20.0229	0.06%	26.8813	0.29%	20.5374	0.07%
2025	24.9253	0.30%	20.0361	0.07%	26.9587	0.29%	20.5514	0.07%
2026	25.0003	0.30%	20.0504	0.07%	27.037	0.29%	20.5665	0.07%
2027	25.0767	0.31%	20.0658	0.08%	27.1163	0.29%	20.5825	0.08%
2028	25.1543	0.31%	20.0829	0.09%	27.197	0.30%	20.6002	0.09%
2029	25.2333	0.31%	20.1013	0.09%	27.279	0.30%	20.6192	0.09%
2030	25.3138	0.32%	20.1212	0.10%	27.3624	0.31%	20.6396	0.10%
2031	25.3955	0.32%	20.1421	0.10%	27.447	0.31%	20.6611	0.10%
2032	25.478	0.32%	20.1637	0.11%	27.5324	0.31%	20.683	0.11%
2033	25.5612	0.33%	20.1863	0.11%	27.6186	0.31%	20.706	0.11%
2034	25.6454	0.33%	20.2098	0.12%	27.7057	0.32%	20.7299	0.12%
2020-2024 Avg		0.30%		0.06%		0.29%		0.06%

Lebanon township seasonal peak forecasts are listed next. As the largest Western PSA township, Lebanon peak growth from 2020-2024 is somewhat higher than the overall system growth.

Lebanon Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	49.4416		40.4163		54.9438		42.5517	
2019	49.7017	0.53%	40.53	0.28%	55.2134	0.49%	42.664	0.26%
2020	49.9308	0.46%	40.608	0.19%	55.4519	0.43%	42.7403	0.18%
2021	50.1438	0.43%	40.6822	0.18%	55.674	0.40%	42.813	0.17%
2022	50.3613	0.43%	40.7679	0.21%	55.9007	0.41%	42.8976	0.20%
2023	50.5842	0.44%	40.8552	0.21%	56.1328	0.42%	42.9834	0.20%
2024	50.8016	0.43%	40.9318	0.19%	56.3593	0.40%	43.0588	0.18%
2025	51.0141	0.42%	41.0076	0.19%	56.5811	0.39%	43.1334	0.17%
2026	51.2263	0.42%	41.0839	0.19%	56.8028	0.39%	43.2086	0.17%
2027	51.4393	0.42%	41.1607	0.19%	57.0247	0.39%	43.2844	0.18%
2028	51.6531	0.42%	41.2393	0.19%	57.248	0.39%	43.3621	0.18%
2029	51.8683	0.42%	41.3192	0.19%	57.4725	0.39%	43.4412	0.18%
2030	52.085	0.42%	41.4009	0.20%	57.6982	0.39%	43.5221	0.19%
2031	52.3027	0.42%	41.4832	0.20%	57.9253	0.39%	43.604	0.19%
2032	52.5208	0.42%	41.5659	0.20%	58.1526	0.39%	43.6857	0.19%
2033	52.7391	0.42%	41.6494	0.20%	58.3806	0.39%	43.7686	0.19%
2034	52.9584	0.42%	41.7339	0.20%	58.6093	0.39%	43.8526	0.19%
2020-2024 Avg		0.44%		0.20%		0.42%		0.19%

Marlow township forecast values are shown next. The Marlow growth is much lower than the system average during the 2020-2024 years.

Marlow Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.0073		0.0059		0.0079		0.0061	
2019	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2020	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2021	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2022	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2023	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2024	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.006	-1.64%
2025	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.006	0.00%
2026	0.0074	1.37%	0.0059	0.00%	0.0079	0.00%	0.006	0.00%
2027	0.0074	0.00%	0.0059	0.00%	0.008	1.27%	0.006	0.00%
2028	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2029	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2030	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2031	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2032	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2033	0.0075	1.35%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2034	0.0075	0.00%	0.0059	0.00%	0.0081	1.25%	0.006	0.00%
2020-2024 Avg		0.00%		0.00%		0.00%		-0.33%

Monroe township peak forecasts are shown below. The annual growth in Monroe Township is smaller than the system average during the 2020-2024 years.

Monroe Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.331		0.2706		0.3529		0.2733	
2019	0.3307	-0.09%	0.2697	-0.33%	0.3526	-0.09%	0.2724	-0.33%
2020	0.3303	-0.12%	0.2686	-0.41%	0.3521	-0.14%	0.2714	-0.37%
2021	0.3299	-0.12%	0.2676	-0.37%	0.3516	-0.14%	0.2704	-0.37%
2022	0.3295	-0.12%	0.2667	-0.34%	0.3512	-0.11%	0.2695	-0.33%
2023	0.3293	-0.06%	0.2659	-0.30%	0.3509	-0.09%	0.2687	-0.30%
2024	0.329	-0.09%	0.2651	-0.30%	0.3507	-0.06%	0.2679	-0.30%
2025	0.3289	-0.03%	0.2643	-0.30%	0.3505	-0.06%	0.2672	-0.26%
2026	0.3287	-0.06%	0.2636	-0.26%	0.3503	-0.06%	0.2665	-0.26%
2027	0.3286	-0.03%	0.2629	-0.27%	0.3502	-0.03%	0.2658	-0.26%
2028	0.3286	0.00%	0.2623	-0.23%	0.3501	-0.03%	0.2652	-0.23%
2029	0.3286	0.00%	0.2617	-0.23%	0.3501	0.00%	0.2646	-0.23%
2030	0.3286	0.00%	0.2612	-0.19%	0.3501	0.00%	0.2641	-0.19%
2031	0.3287	0.03%	0.2607	-0.19%	0.3502	0.03%	0.2636	-0.19%
2032	0.3288	0.03%	0.2603	-0.15%	0.3503	0.03%	0.2631	-0.19%
2033	0.329	0.06%	0.2598	-0.19%	0.3504	0.03%	0.2627	-0.15%
2034	0.3292	0.06%	0.2594	-0.15%	0.3506	0.06%	0.2623	-0.15%
2020-2024 Avg		-0.10%		-0.34%		-0.11%		-0.33%

Plainfield township forecasts appear next. The Plainfield growth rate is peak from 2020-2024 is much lower than the system average over this time frame.

Plainfield Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	1.2609		1.0307		1.3727		1.0631	
2019	1.2626	0.13%	1.0296	-0.11%	1.3744	0.12%	1.062	-0.10%
2020	1.2637	0.09%	1.0278	-0.17%	1.3755	0.08%	1.0602	-0.17%
2021	1.2646	0.07%	1.026	-0.18%	1.3764	0.07%	1.0584	-0.17%
2022	1.2658	0.09%	1.0247	-0.13%	1.3776	0.09%	1.0571	-0.12%
2023	1.2673	0.12%	1.0236	-0.11%	1.3791	0.11%	1.056	-0.10%
2024	1.2688	0.12%	1.0223	-0.13%	1.3806	0.11%	1.0548	-0.11%
2025	1.2704	0.13%	1.0212	-0.11%	1.3821	0.11%	1.0536	-0.11%
2026	1.272	0.13%	1.0201	-0.11%	1.3837	0.12%	1.0526	-0.09%
2027	1.2738	0.14%	1.0192	-0.09%	1.3855	0.13%	1.0517	-0.09%
2028	1.2757	0.15%	1.0185	-0.07%	1.3874	0.14%	1.0509	-0.08%
2029	1.2777	0.16%	1.0178	-0.07%	1.3895	0.15%	1.0503	-0.06%
2030	1.2799	0.17%	1.0173	-0.05%	1.3917	0.16%	1.0497	-0.06%
2031	1.2821	0.17%	1.0169	-0.04%	1.394	0.17%	1.0493	-0.04%
2032	1.2845	0.19%	1.0166	-0.03%	1.3964	0.17%	1.049	-0.03%
2033	1.2869	0.19%	1.0163	-0.03%	1.3988	0.17%	1.0487	-0.03%
2034	1.2895	0.20%	1.0162	-0.01%	1.4014	0.19%	1.0486	-0.01%
2020-2024 Avg		0.10%		-0.14%		0.09%		-0.14%

Surry Township forecast values are listed next. The annual growth in the Surry peak from 2020-2024 is higher than the system average.

Surry Township Peaks								
year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.0534		0.0436		0.0577		0.0447	
2019	0.0537	0.56%	0.0438	0.46%	0.058	0.52%	0.0448	0.22%
2020	0.0539	0.37%	0.0438	0.00%	0.0582	0.34%	0.0449	0.22%
2021	0.0541	0.37%	0.0439	0.23%	0.0584	0.34%	0.0449	0.00%
2022	0.0544	0.55%	0.044	0.23%	0.0587	0.51%	0.045	0.22%
2023	0.0546	0.37%	0.0441	0.23%	0.0589	0.34%	0.0451	0.22%
2024	0.0548	0.37%	0.0442	0.23%	0.0592	0.51%	0.0452	0.22%
2025	0.0551	0.55%	0.0443	0.23%	0.0594	0.34%	0.0453	0.22%
2026	0.0553	0.36%	0.0443	0.00%	0.0597	0.51%	0.0454	0.22%
2027	0.0555	0.36%	0.0444	0.23%	0.0599	0.34%	0.0455	0.22%
2028	0.0557	0.36%	0.0445	0.23%	0.0601	0.33%	0.0455	0.00%
2029	0.056	0.54%	0.0446	0.22%	0.0604	0.50%	0.0456	0.22%
2030	0.0562	0.36%	0.0447	0.22%	0.0606	0.33%	0.0457	0.22%
2031	0.0564	0.36%	0.0448	0.22%	0.0609	0.50%	0.0458	0.22%
2032	0.0567	0.53%	0.0448	0.00%	0.0611	0.33%	0.0459	0.22%
2033	0.0569	0.35%	0.0449	0.22%	0.0613	0.33%	0.046	0.22%
2034	0.0571	0.35%	0.045	0.22%	0.0616	0.49%	0.0461	0.22%
2020-2024 Avg		0.41%		0.18%		0.41%		0.18%

The final township, Walpole forecasts of peak appear below. The Walpole average annual growth is less than the system average for the 2020-2024 years.

Walpole Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	4.9462		4.0433		5.3208		4.1208	
2019	4.9486	0.05%	4.0354	-0.20%	5.3228	0.04%	4.113	-0.19%
2020	4.9489	0.01%	4.0249	-0.26%	5.3229	0.00%	4.1027	-0.25%
2021	4.9485	-0.01%	4.0148	-0.25%	5.3222	-0.01%	4.0928	-0.24%
2022	4.9494	0.02%	4.0066	-0.20%	5.3229	0.01%	4.0847	-0.20%
2023	4.9516	0.04%	3.9993	-0.18%	5.3249	0.04%	4.0775	-0.18%
2024	4.954	0.05%	3.9915	-0.20%	5.327	0.04%	4.0699	-0.19%
2025	4.9565	0.05%	3.9843	-0.18%	5.3294	0.05%	4.0628	-0.17%
2026	4.9596	0.06%	3.9776	-0.17%	5.3324	0.06%	4.0562	-0.16%
2027	4.9633	0.07%	3.9716	-0.15%	5.336	0.07%	4.0503	-0.15%
2028	4.9677	0.09%	3.9661	-0.14%	5.3402	0.08%	4.0449	-0.13%
2029	4.9726	0.10%	3.9613	-0.12%	5.345	0.09%	4.0401	-0.12%
2030	4.9781	0.11%	3.957	-0.11%	5.3504	0.10%	4.0359	-0.10%
2031	4.9841	0.12%	3.9531	-0.10%	5.3564	0.11%	4.0321	-0.09%
2032	4.9906	0.13%	3.9496	-0.09%	5.3628	0.12%	4.0287	-0.08%
2033	4.9974	0.14%	3.9466	-0.08%	5.3696	0.13%	4.0256	-0.08%
2034	5.0047	0.15%	3.944	-0.07%	5.3768	0.13%	4.023	-0.06%
2020-2024 Avg		0.02%		-0.22%		0.02%		-0.21%

APPENDIX A

	LUNH Historic Peak Day Values

year	month	day	hour	Mw
2000	10	30	18	120.587
2000	11	21	18	132.537
2000	12	14	18	133.21
2001	1	10	18	130.276
2001	2	22	19	131.967
2001	3	1	19	117.486
2001	4	24	14	125.857
2001	5	11	16	134.29
2001	6	27	16	159.728
2001	7	24	15	168.319
2001	8	6	14	173.866
2001	9	10	15	142.882
2001	10	4	14	121.58
2001	11	29	18	126.458
2001	12	17	18	137.219
2004	1	14	19	150.948
2004	2	17	19	138.039
2004	3	16	19	135.111
2004	4	30	15	126.933
2004	5	12	16	137.766
2004	6	9	15	166.476
2004	7	22	14	172.492
2004	8	3	15	169.516
2004	9	17	14	141.094
2004	10	8	15	124.583
2004	11	17	18	140.077
2004	12	21	19	151.159
2005	1	18	19	148.961
2005	2	21	19	137.439
2005	3	9	19	141.04
2005	4	20	13	125.3
2005	5	11	15	127.421
2005	6	27	15	184.603
2005	7	19	14	191.871
2005	8	10	16	179.92
2005	9	14	16	158.878
2005	10	25	19	145.312
2005	11	23	18	135.463
2005	12	13	18	161.546
2006	1	23	19	149.003
2006	2	8	19	139.41
2006	3	1	19	134.011
2006	4	4	20	123.651
2006	5	31	17	147.724
2006	6	19	13	181.58
2006	7	18	16	191.959
2006	8	2	15	195.419

2006	9	18	16	138.005
2006	10	4	20	126.699
2006	11	30	18	132.703
2006	12	4	18	146.719
2007	1	26	18	141.539
2007	2	5	19	146.216
2007	3	6	19	144.084
2007	4	4	19	130.327
2007	5	25	16	148.856
2007	6	27	14	187.416
2007	7	27	14	178.707
2007	8	3	15	187.522
2007	9	7	16	165.591
2007	10	22	19	150.267
2007	11	26	18	139.867
2007	12	5	18	152.389
2008	1	3	18	144.175
2008	2	1	18	139.664
2008	3	5	19	132.501
2008	4	23	16	127.896
2008	5	27	14	135.302
2008	6	10	15	195.262
2008	7	8	15	186.04
2008	8	18	16	159.613
2008	9	5	15	163.176
2008	10	9	20	127.515
2008	11	5	18	133.241
2008	12	8	18	146.578
2009	1	14	18	147.427
2009	2	5	19	142.883
2009	3	2	19	138.703
2009	4	28	15	140.767
2009	5	21	16	145.009
2009	6	26	13	145.615
2009	7	29	15	176.68
2009	8	18	14	190.698
2009	9	3	16	139.939
2009	10	28	19	131.489
2009	11	30	18	136.288
2009	12	17	18	154.02
2010	1	12	18	143.943
2010	2	4	19	140.447
2010	3	3	19	131.958
2010	4	7	20	124.039
2010	5	26	16	174.742
2010	6	28	14	171.967
2010	7	7	16	196.543
2010	8	31	17	187.363

2010	9	1	16	186.389
2010	10	1	10	139.359
2010	11	29	18	138.456
2010	12	15	18	149.16
2011	1	24	19	150.041
2011	2	2	18	155.316
2011	3	21	20	144.149
2011	4	28	12	140.458
2011	5	31	16	162.456
2011	6	9	15	183.139
2011	7	22	15	205.939
2011	8	1	15	186.77
2011	9	14	14	157.534
2011	10	10	16	139.923
2011	11	28	18	138.63
2011	12	19	18	146.848
2012	1	16	18	150.194
2012	2	29	19	139.924
2012	3	1	19	140.808
2012	4	16	18	142.882
2012	5	31	14	149.487
2012	6	21	16	192.762
2012	7	17	17	191.846
2012	8	3	16	188.008
2012	9	7	16	165.842
2012	10	15	19	137.546
2012	11	7	18	141.017
2012	12	16	18	149.861
2013	1	24	18	154.659
2013	2	5	19	146.904
2013	3	7	19	139.796
2013	4	12	14	130.322
2013	5	31	16	182.108
2013	6	24	12	191.469
2013	7	19	13	203.761
2013	8	21	17	181.325
2013	9	11	16	191.313
2013	10	2	15	140.756
2013	11	25	18	145.9
2013	12	17	19	159.28
2014	1	2	18	161.33
2014	2	11	19	145.35
2014	3	3	19	144.09
2014	4	15	14	122.63
2014	5	12	16	133.566
2014	6	30	17	172.905
2014	7	23	16	193.21
2014	8	27	16	175.731

2014	9	2	15	177.966
2014	10	16	12	134.995
2014	11	18	18	135.778
2014	12	8	18	143.234
2015	1	8	18	148.541
2015	2	16	19	144.885
2015	3	5	19	137.502
2015	4	2	11	123.717
2015	5	27	16	159.605
2015	6	23	17	149.229
2015	7	30	14	184.893
2015	8	18	14	186.141
2015	9	9	16	187.326
2015	10	13	19	153.086
2015	11	30	18	131.008
2015	12	29	18	133.603
2016	1	9	18	142.592
2016	2	15	18	142.576
2016	3	3	19	129.165
2016	4	4	12	125.539
2016	5	31	16	152.579
2016	6	20	16	167.76
2016	7	28	15	185.985
2016	8	12	16	193.151
2016	9	9	16	176.143
2016	10	17	19	125.149
2016	11	21	18	128.994
2016	12	19	18	143.2
2017	1	9	18	143.485
2017	2	7	19	134.572
2017	3	4	19	127.668
2017	4	11	16	124.478
2017	5	18	16	162.931
2017	6	12	17	181.34
2017	7	20	15	179.727
2017	8	22	17	179.089
2017	9	25	16	172.378

2017	10	9	19	136
2017	11	28	18	129.146
2017	12	28	18	150.426
2018	1	2	18	154.265
2018	2	7	18	135.615
2018	3	7	18	127.866
2018	4	16	12	121.766
2018	5	31	18	145.275
2018	6	18	16	170.718
2018	7	3	14	194.416
2018	8	29	15	197.82
2018	9	5	16	185.689
2018	10	10	16	141.038

Appendix B

Rockingham and Grafton Economic Variabls

Year	Employment	Households	Ratio Employment	Ratio Households	EMP_HH
2000	187.909556	136.67992	0.883437547	0.868487589	0.878499
2001	190.210754	138.994921	0.894256394	0.883197501	0.890603
2002	188.792392	141.139531	0.88758811	0.89682472	0.890639
2003	188.11389	142.7048	0.884398203	0.906770707	0.891788
2004	192.798123	144.091146	0.906420645	0.915579786	0.909446
2005	195.972244	145.783314	0.92134345	0.926332111	0.922991
2006	198.973063	147.631915	0.935451493	0.938078438	0.936319
2007	200.824353	148.693788	0.944155144	0.944825761	0.944377
2008	200.732851	150.063565	0.943724956	0.953529558	0.946964
2009	194.529293	150.820776	0.914559563	0.958341006	0.929022
2010	195.290864	151.627674	0.918140011	0.963468174	0.933113
2011	196.932633	151.990988	0.92585862	0.965776733	0.939045
2012	199.207744	153.358134	0.936554822	0.974463813	0.949077
2013	201.188058	154.136489	0.945865066	0.979409614	0.956946
2014	203.497594	153.967144	0.956723113	0.978333567	0.963862
2015	206.784935	154.604545	0.97217821	0.982383722	0.975549
2016	209.789856	155.970247	0.986305539	0.991061626	0.987877
2017	212.702705	157.376941	1	1	1
2018	216.594529	159.020301	1.018297012	1.010442191	1.015702
2019	219.530696	160.178698	1.032101101	1.017802843	1.027378
2020	220.939724	161.212455	1.038725502	1.024371512	1.033984
2021	222.306633	162.130018	1.045151885	1.030201864	1.040214
2022	224.20116	163.196886	1.054058809	1.036980926	1.048418
2023	226.155081	164.359214	1.063244969	1.044366557	1.057009
2024	227.736127	165.42675	1.070678095	1.051149863	1.064227
2025	229.310686	166.501942	1.078080723	1.057981817	1.071442
2026	230.937906	167.622535	1.085730931	1.065102257	1.078917
2027	232.615046	168.783076	1.093615833	1.072476533	1.086633
2028	234.367337	169.997032	1.10185405	1.080190217	1.094698
2029	236.235999	171.209275	1.110639373	1.087893016	1.103126
2030	238.188653	172.464594	1.119819576	1.095869528	1.111908
2031	240.21632	173.724622	1.129352445	1.103875961	1.120937
2032	242.281408	174.98734	1.139061245	1.111899487	1.130089
2033	244.416009	176.245366	1.149096853	1.1198932	1.13945
2034	246.633113	177.497101	1.159520341	1.127846938	1.149058

Appendix C

year	month	day	hour	system mw	psa total	mw_e	mw_w	Eastern %	Western %
2014	3	3	19	144.09	144.0875	66.7299	77.3576	46.31%	53.69%
2014	4	15	14	122.63	122.6254	50.2352	72.3902	40.96%	59.04%
2014	5	12	16	133.566	133.5654	57.9524	75.613	43.39%	56.61%
2014	6	30	17	172.905	156.8357	69.5198	87.3159	40.21%	59.79%
2014	7	23	16	193.213	193.2128	96.326	96.8868	49.85%	50.15%
2014	8	27	16	175.731	175.7307	87.134	88.5967	49.58%	50.42%
2014	9	2	15	177.966	177.966	87.896	90.07	49.39%	50.61%
2014	10	16	12	134.995	134.9956	54.57	80.4256	40.42%	59.58%
2014	11	18	18	135.892	135.8918	62.217	73.6748	45.78%	54.22%
2014	12	8	18	143.321	143.3214	68.071	75.2504	47.50%	52.50%
2015	1	8	18	148.451	148.4504	69.655	78.7954	46.92%	53.08%
2015	2	16	19	144.833	144.8328	68.698	76.1348	47.43%	52.57%
2015	3	5	19	137.502	137.5021	63.046	74.4561	45.85%	54.15%
2015	4	2	11	123.717	123.7167	53.196	70.5207	43.00%	57.00%
2015	5	27	16	173.241	173.2414	80.931	92.3104	46.72%	53.28%
2015	6	23	17	163.897	163.8974	76.974	86.9234	46.96%	53.04%
2015	7	30	14	185.508	185.5081	88.65	96.8581	47.79%	52.21%
2015	8	18	14	186.141	186.141	90.612	95.529	48.68%	51.32%
2015	9	9	16	187.326	187.3256	90.746	96.5796	48.44%	51.56%
2015	10	13	19	126.066	126.0657	54.757	71.3087	43.44%	56.56%
2015	11	30	18	131.179	131.1792	61.125	70.0542	46.60%	53.40%
2015	12	29	18	135.02	135.0195	64.717	70.3025	47.93%	52.07%
2016	1	19	18	142.656	142.6563	66.52	76.1363	46.63%	53.37%
2016	2	15	18	142.576	142.576	66.849	75.727	46.89%	53.11%
2016	3	3	19	129.165	129.1652	58.534	70.6312	45.32%	54.68%
2016	4	4	12	125.627	125.6264	55.789	69.8374	44.41%	55.59%
2016	5	31	16	152.932	152.9326	72.016	80.9166	47.09%	52.91%
2016	6	20	16	168.23	168.2302	80.188	88.0422	47.67%	52.33%

2016	7	28	15	187.268	187.268	92.677	94.591	49.49%	50.51%
2016	8	12	16	193.773	193.7728	101.455	92.3178	52.36%	47.64%
2016	9	9	16	176.143	176.1425	88.094	88.0485	50.01%	49.99%
2016	10	17	19	125.149	125.1491	54.943	70.2061	43.90%	56.10%
2016	11	21	18	128.994	128.9941	59.783	69.2111	46.35%	53.65%
2016	12	19	18	143.2	143.2006	68.277	74.9236	47.68%	52.32%
2017	1	9	18	143.485	143.4859	67	76.4859	46.69%	53.31%
2017	2	7	19	134.572	134.5725	62.075	72.4975	46.13%	53.87%
2017	3	4	19	127.668	127.6675	59.331	68.3365	46.47%	53.53%
2017	4	11	16	124.478	124.4777	53.157	71.3207	42.70%	57.30%
2017	5	18	16	162.931	162.9316	80.043	82.8886	49.13%	50.87%
2017	6	12	17	181.34	181.3401	93.591	87.7491	51.61%	48.39%
2017	7	20	15	179.727	179.7268	89.606	90.1208	49.86%	50.14%
2017	8	22	17	179.089	179.0891	88.946	90.1431	49.67%	50.33%
2017	9	25	16	172.378	172.378	80.833	91.545	46.89%	53.11%
2017	10	9	19	136	136.0002	59.58	76.4202	43.81%	56.19%
2017	11	28	18	129.146	129.1464	60.506	68.6404	46.85%	53.15%
2017	12	28	18	150.426	150.4257	73.259	77.1667	48.70%	51.30%
2018	1	2	18	154.265	154.265	73.013	81.252	47.33%	52.67%
2018	2	7	18	135.615	135.6153	62.193	73.4223	45.86%	54.14%
2018	3	7	18	127.866	127.8662	58.701	69.1652	45.91%	54.09%
2018	4	16	12	121.766	121.7653	54.945	66.8203	45.12%	54.88%
2018	5	31	18	145.275	145.2743	67.507	77.7673	46.47%	53.53%
2018	6	18	16	170.718	170.718	83.684	87.034	49.02%	50.98%
2018	7	3	14	194.416	194.4155	95.599	98.8165	49.17%	50.83%
2018	8	29	15	197.82	197.8195	100.733	97.0865	50.92%	49.08%
2018	9	5	16	185.689	185.6899	90.481	95.2089	48.73%	51.27%
2018	10	10	16	141.038	141.0376	62.74	78.2976	44.48%	55.52%

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

OCA Data Requests - Set 4

Date Request Received: 7/24/19
Request No. OCA 4-6

Date of Response: 8/7/19
Respondent: Joel Rivera

REQUEST:

Provide any documents in the utility's possession describing any internal processes or software systems the utility uses to manage risk, including:

a. How the utility identifies potential risks;
b. How the utility estimates the probable incidence of each potential risk;
c. How the utility estimates the likely consequences of each incident;
d. How the utility estimates the financial impact associated with an incident;
e. How the utility employs these risk identification and estimation processes in distribution investment decisions.

RESPONSE:

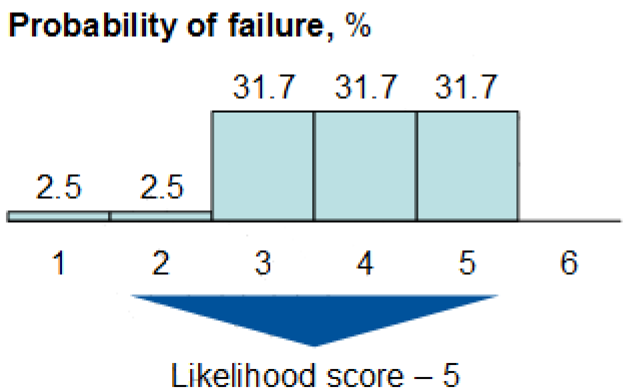
a. Please refer to Section 4 and Section 5 of the Company's LCIRP (https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-097/INITIAL%20FILING%20-%20PETITION/16-097_2016-01-15_GSEC_DBA_LIBERTY_LCIRP.PDF) for how the Company identifies potential risks. Please refer to the response to OCA 4-4 for information on systems that the utility uses to manage certain risks.

   Refer to Attachment OCA 4-6 for the risk scoring matrix the Company utilizes for distribution investments. This matrix provides a relative risk ranking for investments and is used as a decision support tool in measuring and prioritizing risks. It is not a decision making tool.

   Risks are evaluated and prioritized based on two criteria: (1) the impact or consequence of the risk, taking into account factors such as financial risk, the number and outage duration of customers impacted, load at risk, loading, voltage performance, and pocket frequency; and (2) the likelihood that such impacts will occur, ranging up to 1 in over 100 years. Once both the consequence and likelihood of occurrence of a risk are determined, the risk score is determined by scrolling across the table to where both scores intersect. It is possible that a system deficiency may have more than one risk. For example, a distribution feeder could be projected to exceed its normal loading rating in 5 years but could also be in current violation of the MWhr criteria. In this case, the highest risk is chosen.

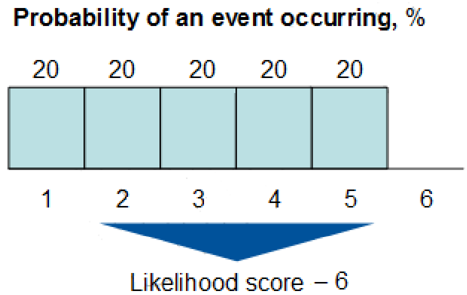
b. The probable incidence of each potential risk is estimated using the following approaches:

- Time to failure approach (results in likelihood scores after considering time to failure).
    - o The earliest and latest time to failure for an asset is established.
    - o The resulting likelihood score is derived by scrolling across the table. For example, if an asset is not expected to fail in the next two years, but is expected to fail in three to five years, the likelihood score is 5.



Time to failure (in years)	Likelihood level
<1 years	7
1 to 3 years	6
3 to 5 years	5
5 to 10 years	4
10 to 20 years	3
20 to 100 years	2
>100 years	1

- Time to certain event approach (results in likelihood scores after considering the time to a certain impact or the probability of an impact happening the following year (assuming uniform distribution)).
    - o The time to a certain impact or the probability of a certain impact happening the following year is established.
    - o The resulting likelihood score is derived by scrolling across the table. For example, if an event will happen in the next five years, such as a forecasted overload, (or the probability of the event happening the following year is 20%), the likelihood score is 6.



Years to certain impact	Likelihood level	Probability of certain impact happening next year
1	7	100%
2	7	50%
3	6	33%
5	6	20%
6	5	17%
10	5	10%
20	4	5%
100	4	1%
200	3	0.5%
500	2	0.2%
1000	2	0.1%
2000	1	0.05%

c. The consequence for each incident is estimated using the table provided in Attachment OCA 4-6. Consequences are of varying impact from Very Low to Very High are based on the magnitude of the identified deficiency needing to be addressed.

d. The levels of financial impact are provided in Attachment OCA 4-6, column labeled "$." Financial impact can be estimated for some risks. For example, financial impact to equipment failure can be determined from historical financial data from the replacement of similar equipment or from established investment grade estimates.

e. Please refer to Section 4 and Section 5 of the Company's LCIRP on how the Company employs risk identification and prioritization in distribution investment decisions.

Each year, the Company develops an Annual Five-Year Investment Plan designed to achieve its overriding performance objective of providing safe, reliable service at reasonable cost to our customers. At the outset, the Investment Plan represents a compilation of proposed spending for programs and individual capital projects. Programs and projects are categorized by spending priority, i.e., Safety, Growth, Mandated, Regulatory Programs, and Discretionary. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects as well as initial estimates for newly proposed projects.

All mandatory programs and projects known at this point are included in the plan. Examples of mandatory programs and projects include public requirements, which necessitate the relocation of our facilities, response to damage/failure and storms, and third party attachments. Once the mandatory budget level has been established, programs and projects in the other categories (i.e., growth, regulatory programs, and discretionary) are reviewed for inclusion in the investment plan.

Plan inclusion/exclusion for any given project is based on several factors including, but not limited to: project new or in-progress status, risk/benefit, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed to optimize the total cost and outage planning. The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project.

The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. From an overall perspective, the Company's objective is to arrive at a capital plan that is the optimal balance in terms of making the investments necessary to maintain and improve the performance of the system for customers, while also ensuring a cost-effective use of the Company's available resources.

Risk Calculation Matrix

Impact / Consequence		Matrix Risk Score	$	Asset Replacement only CUSTOMERS SERVED	Impact Level	CI per event	CMI per event	MW at risk	MWh at risk	Normal Loading (%)	Voltage (pu)	Pocket Frequency
1	Very Low	1	≤5k	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
2	Low	2	>5-≤10k	100 < 500	Recl or Fuse Tap	≤500	≤30k	≤1.5	≤16	Not Used	Not Used	2
3	Moderately Low	3	>10-≤50k	500 < 1500	≤0.5 Feeder	>500≤1500	>30k≤90k	>1.5≤2.5	>16≤20	>75≤100	Not Used	3
4	Moderate	4	>50k-≤100k	1500 < 2000	>0.5≤1 Feeder	>1500≤2000	>90k≤120k	>2.5≤5	>20≤24	>100≤105	<0.95≥0.94	3-5
5	Moderately High	5	>100k-≤500k	2000 < 5000	>1≤3 Feeders	>2000≤5000	>120k≤300k	>5≤10	>24≤30	>105≤110	<0.94≥0.92	5-8
6	High	6	>500k-≤1M	5000 < 10000	>3≤5 Feeders	>5000≤10000	>300k≤600k	>10≤20	>30≤40	>110≤120	<0.92≥0.90	8-10
7	Very High	7	>1M	>10000	>5 Feeders	>10000	>600k	>20	>40	>120%	<0.90	>10
50	Mandatory											

Risk Score Matrix									
Impact / Consequence		Risk Value							
Very High	7	25	32	38	43	47	48	49	
High	6	20	29	33	40	44	45	46	
Moderately High	5	15	22	26	35	39	41	42	
Moderate	4	9	17	19	28	34	36	37	
Moderately Low	3	5	10	14	21	27	30	31	
Low	2	3	6	8	16	18	23	24	
Very Low	1	1	2	4	7	11	12	13	
		1	2	3	4	5	6	7	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	

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 1

Date Request Received: 10/18/19
Request No. Staff TS 1-30

Date of Response: 11/1/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Response to Staff 6-23 (d). Does the contingency analysis for Spicket River also include any feeder ties with National Grid located on Liberty Street in Salem and Route 97 in Salem?

a. If the response is no, please provide any documentation from National Grid indicating that the feeder tie is not available for contingency situations.

b. Please provide the N-1 contingency analysis of the loss of the 23kV line to Spicket River utilizing 2019 loading data and indicate if the loading analysis includes National Grid as stated above.

RESPONSE:

a. Liberty's contingency analysis does not include ties with neighboring utilities as these are not guaranteed. The ties between National Grid and Spicket River are only with the 13L3 feeder and are used when outages are planned for maintenance needs. During the Quinn storm event in March 2018, these ties were not available as it was difficult to communicate with National Grid given their large service territory and other pending emergencies. These ties are located in National Grid's service territory and are not operated by Liberty personnel. There is no documentation provided by National Grid indicating that any feeder tie with Liberty Utilities is available at any given point as these are not guaranteed.

b. The loss of the 23 kV source for an outage on the 5.2 mile section would require the Spicket River circuits to be backed up by existing distribution circuit ties. Based on 2019 loading, the total Spicket River load is 24.2 MVA.

   The table below represents the available capacity on the 13.2 kV tie circuits as well as load at risk by circuit using 2019 actual loads, without considering the National Grid ties.

2019 Actual Loads				
Distribution Circuit	Ties	Available Capacity	Load at Risk (Amps)	Load at Risk (MVA)
13L1	13L2, 13L3	0	326	7.45
13L2	9L1, 9L3	279	11	0.25
13L3	10L2, 9L1, 18L2	261	182	4.16

Loss of the 23 kV sub-transmission supply circuit to the Spicket River No.13 Station would result in approximately 11.9 MVA of load at risk, after restorative switching occurs. This is an increase from 7.6 MVA of load at risk in 2016.

Liberty Utilities relies on the transmission provider to expedite repairs should an outage related problem occur anywhere along the 4.2 miles of transmission-owned 2376 sub-transmission line downstream of the 2376/2353 tie. This could cause Liberty Utilities to have up to 160 MWHrs of load at risk, after restorative switching has occurred, for an assumed repair time of 12 hours. This amount of load at risk violates Liberty's planning criteria.

The 9L1 has ties with both the 13L2 and the 13L3 feeder, which could pose difficulties in supporting both Spicket River feeders.

The former planning criteria by National Grid is not appropriate for a system the size of Liberty Utilities. According to the National Grid criteria, the transmission provider is required to return the failed sub-transmission line to service within 12 hours and is allowed 240 MWHrs of load at risk. A more conservative approach should be taken in this case because the 23 kV supply line feeding Spicket River Station is a sole source circuit without any contingency sub-transmission backup within Liberty Utilities' operating territory, and because of difficulties communicating with National Grid during emergencies as evidenced by Storm Quinn. The more conservative approach will eliminate reliance on the Transmission provider and allow Liberty Utilities to significantly reduce load at risk.

The table below represents the available capacity on the 13.2 kV tie circuits as well as load at risk by circuit using 2022 forecasted loads. This does not include ties with National Grid.

2022 Forecasted Loads (Extreme Weather Scenario)				
Distribution Circuit	Ties	Available Capacity	Load at Risk (Amps)	Load at Risk (MVA)
13L1	13L2, 13L3	0	379	8.66
13L2	9L1, 9L3	107	230	5.26
13L3	10L2, 9L1, 18L2	153	362	8.28

Loss of the 23 kV sub-transmission supply circuit to the Spicket River No.13 Station would result in approximately 22.2 MVA of load at risk, after restorative switching occurs. This could cause Liberty Utilities to have up to 269 MWHrs of load at risk, for an assumed repair time of 12 hours, after restorative switching has occurred. This violates Liberty's planning criteria.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 1

Date Request Received: 10/18/19
Request No. Staff TS 1-31

Date of Response: 11/1/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Response to Staff 6-23 (e).

a. Please provide the contingency analysis for the loss of the Goldenrock #1 transformer utilizing National Grid's capacity on the 23kV lines (2353 and 2376?) lines utilizing 2019 load data.

b. If the above analysis does not address the following questions, please provide the following:

   i. Does the "out of service" load stated in the response a post-switching load?
   ii. Does the load include future load that was not present in 2019 loading data?

c. Provide the size and type, normal, and emergency rating of the 23kV conductor from Goldenrock to Old Trolley riser structures on South Broadway.

d. The response also states that the 10MW and 240 MWhrs is above both Liberty and National Grid Planning criteria. Liberty Utilities LCIRP submitted in 2019 states a 60MWhr risk of load following post switching as a criterion. According to Attachment Staff 8-63.1, Bates Page 0034, in docket DE 16-383, National Grid Planning criteria in 2011 was 10MW and 240 MWhrs. Please provide the National Grid criteria that supports the above statement if different from the criteria provided in Staff 8-63.1 in docket 16-383.

e. In Liberty's 2019 LCIRP, Bates Page 0156, A substation N-1 contingency is stated as " If more than 60MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts and the cost to mitigate."

   i. Did the Company analyze the cost to mitigate in respect to the guideline of the risk being "evaluated and prioritized?" If so, please provide the documentation that illustrates that "evaluation and prioritization."
   ii. Did the Company weigh the contingency of loss of non-company asset (115kV-23kV National Grid transformer at Goldenrock) during a limited load period

where the load creates this contingency that ultimately results in an excludable reliability event in IEEE and PUC defined terms?

iii. Please provide the historical outage data for a loss of the #1 Transformer, if that is the equipment used in the analysis, at Goldenrock for 2009-2019.

f. Liberty states, "Simply replacing discrete pieces or groupings of equipment would not be feasible due to the multiple equipment deficiencies at the substations. Maintaining, repairing, or replacing the assets in their existing location and configuration, while possible, would be costly and would not be expected to yield a significant improvement in the overall reliability or operability of the substation. Due to the design and overall condition of the steel, foundations, bus, switches, and control houses, both substations would require significant rebuild in situ. Prior experience retrofitting vintage modular or box structure substations supports the notion that retrofit costs can quickly escalate."

i. Does the Company have a detailed estimate and breakdown of a detailed replacement/refurbishment proposal for addressing the asset issues at Salem Depot and Barron Avenue by qualified substation vendors?

1. If yes, please provide the documentation.
2. If no, please explain why not?
3. Are the vendors' estimates based on the Company's maintenance records and standards documents? If so, please indicate the applicable documents.
4. Is the asset replacement/restoration estimate part of the 2017 Area Engineering study or business justification/project justification for the Rockingham substation and Goldenrock 13kV installation?

RESPONSE:

a. Under the contingency of losing the existing transformer at Golden Rock and using 2019 peak loads, the contingency load on the 2353 line would result in being loaded above its emergency rating by 5.1 MVA. The 2353 supply would likely trip at the source given this overload. Using 2019 peak loads, the contingency load on the 2376 line would result in being loaded under its emergency rating and would not trip. However, if the transfer schemes at the individual substations are not blocked, the resulting load transfers could result in the 2376 being loaded above its emergency rating and thus trip as well. Ultimately it is anticipated that the 5.1 MVA of load above emergency rating can be mitigated by transferring additional load to Spicket River and thus not result in a criteria violation.

This 2019 contingency analysis for Golden Rock is skewed by the fact that Liberty extended the Pelham 14L4 feeder into the Town of Salem to allow transferring load from Golden Rock to Pelham. In 2019 these transfers started taking place, which resulted in approximately 300A or 6.9 MVA of Golden Rock load transferred to Pelham. Additional transfers from Golden Rock to Pelham are planned for 2020 to create additional capacity for Tuscan Village. The Company installed the 14L4 feeder to reduce the load at risk from Golden Rock and to provide temporary capacity for Tuscan Village until the Rockingham Substation can be built.

Under the contingency of losing the existing transformer at Golden Rock and using 2022 forecasted peak loads, the contingency load on the 2353 and 2376 lines would result in being loaded above their emergency rating by 15.7 MVA and 12.8 MVA respectively, even with the transfers to Pelham 14L4. Given the limited capacity in the area to transfer load to Pelham or Spicket River, the resulting MWhr at risk on the 2353 and 2376 lines could result in the range of 306 for each line.

There are several other criteria violations that would result for the 2022 forecasted year.

See Attachment Staff TS 1-31.a.xls for further details. This summary is provided using 2019 peak loads for the Salem planning study area and account for transfers to Pelham 14L4.

b. See the response to Staff TS 1-30.

   i. Yes
   ii. Results are provided for both 2019 actual loads and forecasted 2022 loads.

c. See Confidential Attachment Staff 1-3.b.(a).1.xls submitted in Docket No. DE 19-120.

d. Liberty is unaware of any planning criteria changes by National Grid since what was provided in Docket DE 16-383.

e. As follows:

   i. The Golden Rock load at risk was evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate. Using 2018 load data, in 2022 the risk score was categorized as 47, which is among the highest for Liberty. See Attachment Staff 1-3.b.(a).5.xls submitted in Docket No. DE 19-120, which contains a summary of identified deficiencies and risk scores forecasted for 2022 using 2018 load data. This summary was updated using 2019 load and provided in Attachment Staff TS 1-31.a.xls. Other projects related to the Company's responsibility to serve new customers in its service territory are categorized as 50 – Mandatory. Examples of this are blanket projects, public requirements, Golden Rock Substation, Golden Rock 19L8, Golden Rock 19L6, Golden Rock 23kV relocation, Rockingham Substation, Rockingham Substation Transmission Supply, and Rockingham Distribution feeders required to serve new customer growth.

   ii. A loss of supply from another utility or transmission outage does result in a PUC excludable event, however Liberty's customers are still impacted and the risk is major to Liberty Utilities. When reporting to the PUC, some year-end numbers provided annually are: No Exclusions, Excludes only PUC Major Events, Excludes only Loss of Supply by other Utility or Transmission Outage, and All Exclusions using PUC criteria. Please refer to the Company's annual reconciliation report for REP/VMP for detailed metrics reported to the PUC.

   A loss of supply from another utility or transmission outage is reported using IEEE criteria; thus, still posing a reliability impact and risk to Liberty. Typical values reported under the IEEE criteria are: SAIDI with MED, SAIFI with MED, CAIDI with MED, SAIDI without MED, SAIFI without MED, CAIDI without MED, SAIDI with MED minus LOS, SAIFI with MED minus LOS, and CAIDI with MED minus LOS. Please refer to US Energy Information Administration's annual survey.

iii. There are no reported instances of transformer failures at the Golden Rock substation.

f. As follows:

i. The Company does not have detailed estimates or breakdowns by qualified substation vendors. The Salem Area Study identified a risk where two Salem Depot Substation transformers would require replacement due to asset condition if the new Rockingham Substation were to be significantly delayed. Refer to Table 17 of the Salem Area Study. This replacement aims to mitigate asset condition at the Salem Depot substation and is not intended to provide capacity to supply the Tuscan loads.

1. Not applicable.
2. The 23kV system does not contain the necessary capacity to supply the future loads in the Salem Area. This, coupled with the existing asset condition issues at Salem Depot and Baron Ave, and the load at risk at Spicket River, prompted the Company to implement a strategy to move away from the 23kV system and into a more robust 115kV system. See the response to Staff 6-39 for further details on the Company's strategy to move to an 115kV based system.
3. Not applicable.
4. The asset condition of Salem Depot and Baron Ave substations and the load at risk that result from the area's projected loads are considered in the Salem Area Study.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 1

Date Request Received: 10/18/19
Request No. Staff TS 1-33

Date of Response: 11/14/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Responses to 6-24 and 6-36.

a. Please provide an updated development project similar to what is shown in 6-24 b.1 and b.2 with the buildings depicted on the drawing that have permanent electric service as of 8-31-19.
b. Please provide the narrative on the above buildings listed in 8a. above as it relates to the schedule legend on the drawings.
c. The loading on the park as depicted in 6-36 attachment (excel spreadsheet) does not align with the Company's earlier response of 2.094 MW, please explain the discrepancy.

RESPONSE:

a. Please reference Attachment TS 1-33.a. Please note the following comments regarding the attachment:
    - The buildings identified in Box 1 are located on the Southern Parcel. They are currently under construction with an expected Spring 2020 Completion Date.
    - The building identified in Box 2 is located on the Southern Parcel. This building is also under construction with an expected Fall 2020 Completion Date.
    - The building identified in Box 3 is located on the Southern Parcel. This building is also under construction with an expected Winter 2020 Completion Date.
    - The building identified in Box 4 is located on the North Parcel and is known as Salem Ford. This building was energized on 3/28/2018.
    - The buildings identified in Box 5 are located on the North Parcel and are known as the Dolben Property. There are five buildings located on this parcel. Each building was energized at different times in accordance with the Developer's Construction Schedule. Energization dates are as follows: 3/1/2018; 8/31/2018;

10/09/2018; 11/29/2018; and 1/25/2019. It should be noted that these buildings are not yet fully occupied with residents.

- The building identified in Box 6 is located on the North Parcel and consists of five Commercial Units. Two of these units are currently occupied while the remaining three are empty. The first commercial unit is occupied by Market Basket. Construction power for Market Basket was energized on 12/10/2018, but Market Basket did not open until 7/1/2019. The second unit is occupied by HomeSense. Construction power was energized on 5/20/2019, but HomeSense did not open until 7/1/2019.
- The buildings identified in Box 7 are located on the North Parcel and are known as Black Brook Properties. There are twelve buildings located on this parcel. Nine buildings have been constructed and three buildings are still under construction. There are various energization dates associated with this parcel between 5/22/2018 and 9/12/2019.
- The buildings identified in Box 8 have not yet been constructed. The Developer has not indicated when construction will begin.
- The buildings identified in Box 9 are not built. The Developer has indicated this portion of North Parcel is currently being redesigned.

b. Please see the response to part a.

c. The Company's earlier response of 2.094 MW was based on an estimate that relied on the anticipated annual kWh sales using industry load estimates. The Excel spreadsheet provided as Attachment Staff 6-36.xlsx gives actual load readings from two of the Company's pole mounted reclosers that supply the Tuscan development. Due to construction delays as a result of the developer's redesigning portions of the North parcel, the northern portion of the Tuscan development has yet to reach its maximum demand. The Company will continue to monitor this peak load.

TUSCAN VILLAGE

170 ACRE TUSCAN VILLAGE MASTERPLAN

PARKING (50 acres):	PROGRAM 50 Acres	SF.
1,700 Cars	*Retail*	160,700 sf
	Car Dealer	38,500 sf
	Multi-Family	256 units (260,000 sf) (+6,000 sf Clubhouse)
	Townhomes	96 units (300,000 sf)
	Total	**765,200 sf**

PARKING (120 acres):	PROGRAM 120 Acres	SF.
6,251 Cars	*Retail*	562,250 sf
	Tuscan Retail	12,000 sf
	Tuscan Hotel	+/- 160 rooms (134,000 sf)**
	Medical Office (Outparcel)	200,000 sf
	Office (Village)	100,000 sf
	Office (Outparcel)	475,000 sf
	Residential (Outparcel)	281 units (295,500 sf) 8,500 sf Amenity & Pool
	Residential (Village)	75 units (64,000 sf)
	Assisted Living	165 units (180,000 sf)
	55+ Duplex Development	30,000 sf
	Maintenance Garage	18,000 sf
	Total	**2,079,250 sf**

****Hotel SF & Program Breakdown**
Basement (mechanical): 12,500
Floor 1 (amenities, retail, banquet): 34,500 sf
Floors 2-4 (rooms) : 87,000 sf
Total SF: 134,000 sf

0 100 200 400

PRELLWITZ CHILINSKI ASSOCIATES

TUSCAN VILLAGE - MASTERPLAN
SALEM, NEW HAMPSHIRE
07/31/2018

3

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 2

Date Request Received: 10/22/19
Request No. Staff TS 2-9

Date of Response: 11/5/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Re: Staff 9-3; Project 8830-C42921 Install Splices – 6L2 & 6L4. Please provide the following information for this project:

a. An itemized breakout of burdens, AFUDC, and other costs leading to the variance of -$91,743.

b. Why was the original cost estimate set at $75,000 (Staff 9-3.2 at 27) and not $111,552?

c. Why was the potential for costs involving contractors, corrosion inside manholes, traffic control, pumping and cleaning manholes, not taken into consideration during the preliminary engineering and budgeting for this project?

d. Why was the Over Expenditure Form (See OCA Data Request 2-14.d.2 at 97) approved and signed in February 2018 instead of during the project year in 2017?

e. Work Orders/spreadsheets including #'s 8830-18002089, 8830-18002322, and 8830-18002089.

f. Please indicate if splices are a minor plant?
   1. If so, why is the labor costs capitalized?
   2. Please provide documentation that indicates the change from expense to capital and the associated company policy that is utilized for that determination.

RESPONSE:

a. Please see Attachment Staff 2-9.a.xlsx.

b. At the time of the estimate, this is what the Company projected the cost to be.

c. As noted during the technical session, the manholes were inspected prior to construction and found no issues. Once construction started, the manholes needed pumping and cleaning and thus the Company needed to complete this work prior to starting construction. Once the cables were moved during construction, corrosion was seen and needed to be remedied. Also, discussed at the tech session was the need for police detail when originally the town allowed for the use of flaggers during construction, but due to the location and the equipment encroaching on the road, police detail was later required by the town.

d. Over expenditure forms are completed on an annual basis and would be completed during the year and signed after the year ends.

e. Please see the response to part a.

f. When a splice extends the life of the cable, it can be capitalized. The Company relies on Attachment Staff TS 2-9.f.1 to provide guidance on this issue. The following Attachments are provided for this project:

- Attachment Staff TS 2-9.f.1: Plant Investment Procedure 613 for plant account 367.26.06 Disconnecting Device - URD/UCD – The reasoning behind this was replacement of the failing H disconnectable joints will extend the actual useful life of the 6L2/6L4 underground distribution system installed in 2010.
- Attachment Staff TS 2-9.f.2: Manhole records of the work completed.
- Attachment Staff TS 2-9.f.3: Drawing providing where the failing H joints were replaced.

NEW ENGLAND POWER SERVICE COMPANY
PLANT INVESTMENT PROCEDURE - 613
ELECTRIC PLANT UNITS

Account: UNDERGROUND CONDUCTORS AND DEVICES
DISTRIBUTION PLANT 367.01

NUMBER	TITLE	DESCRIPTION	UNIT MEASURE
367.24.01	CUTOUT	Oil Filled	Each
367.25.01	CUTOUT	Explusion Type	Each
367.26.01	OIL SWITCH		Each
367.26.03	SWITCH	Automatic Throwover Type	Each
367.26.04	SWITCH, DISCONNECT		Each
367.26.05	LOAD BREAK SWITCH OR VACUUM SWITCH		Each
367.26.06	DISCONNECTING DEVICE - URD/UCD ✓		Each
367.27.01	RELAY		Each
367.27.02	LINE FAULT INDICATOR, SUBMERSIBLE - URD		Each
367.27.03	LINE FAULT INDICATOR	(Consisting of: Control Cable, Sensors and Cabinet)	System
367.28.01	INSTRUMENT TRANSFORMER		Each
367.29.01	GROUND		Each
367.30.01	BUS SUPPORTING STRUCTURE		Each
367.31.01	ENCLOSED SWITCHING CENTER	Group 1, 0-1,000 C.F. - Include, Pad-mounted metal-clad Switchgear Assembly Units	Assembly
367.31.02	ENCLOSED SWITCHING CENTER	Group 2, 1001 - 2000 C.F.	Assembly
367.31.03	TRANSCLOSURE	For Housing Only	Each
367.32.01	FOUNDATION	Equipment	Each
367.33.01	TERMINAL JUNCTION BOX		Each
367.34.01	INSTRUMENT CABINET		Each

Appendix D - Distribution Planning Criteria Summary

1.0 Introduction

This document summarizes the Distribution Planning Criteria and Strategy that will be used by the Engineering Department of Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company") to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA").

2.0 Equipment Ratings

Thermal limits are recognized for all system elements in conducting planning studies. The current in equipment and lines are limited so that voltage drops are held to reasonable values; so that conductors will not be severely annealed or damaged; so that switches, connectors, etc. will not be overloaded and that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures, 2) load cycles, 3) wind velocities, and 4) potential loss of life of equipment.

Liberty's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

Figure D-1 summarizes the Equipment Rating criteria:

Figure D-1. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**
Normal	Continuous	• The maximum value for normal peak loads on all new and rebuilt feeders • Temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, & covered conductors	Continuous	• Maximum loading that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle • Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	• Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or • The Top Oil Temperature exceeds 110 °C, or • The Hot Spot Copper temperature exceeds 180 °C
LTE	24 Hours	• The absolute maximum ampacity allowed for a given conductor and should not be exceeded at any time. • Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, & covered conductors	100 - 300 Hours	• Maximum loading that does not cause the conductor temperature to exceed its design value over several consecutive 24-hour load cycles. • Emergency cable ampacities are based on 130° insulation operating temperature.	1 - 300 Hours	• Level for the peak hour with the emergency load added in the 24-hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer life, or • the Top Oil Temperature exceeds 130 °C, or • the Hot Spot Copper temperature exceeds 180 °C
STE	As Needed	• Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	• Maximum loading that does not cause the conductor temperature to exceed its allowable emergency value at any time during a 24-hour load cycle. • Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	• The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer Life, or • a hot spot copper temperature exceeding 180°C. • Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

3.0 Planning Criteria

For normal loading conditions on distribution feeders and transformers, the planning criteria is based on facilities to remain within 75% of normal ratings at all times. For sub-transmission lines, facilities are to remain within 90% of normal ratings.

For N-1 contingency situations, the planning criteria is based on interrupted load returning to service within a reasonable time via system reconfiguration through switching, installation of temporary equipment, such as mobile transformers or generators, and/or by repair of a failed device. Where practical, switching flexibility is integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Figure D-2 shall guide loading and contingency planning on the distribution system:

Figure D-2. Distribution System Planning Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

Application of these criteria will result in somewhat less load at risk than previous criteria which generally limited load at risk to between 4 and 20 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the new criteria for both normal and N-1 contingency conditions are shown in Figure D-3:

planned, measured, and operated with the objective of providing electric service to customers under system intact conditions (i.e., "normal") and first contingency conditions ("N-1").

1.2 New Planning Criteria

Since the purchase of the New Hampshire electric assets from National Grid in 2012, Liberty Utilities has refined the distribution planning criteria to better fit Liberty's strategy and scale of facilities.[1] These refinements, such as reducing the normal operating ratings limit from 100% to 75% on feeders and transformers and from 100% to 90% on supply lines, 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.

Table 2 shows an estimate of additional facilities that may be required as a result of new planning criteria for the entire system over the next 15 years, based on the results of a sample of areas.

Table 2. Additional Facilities as a Result of New Criteria

Asset	Additional Quantity Required
Transformers (at existing or new substations)	0
Sub-Transmission Lines	0
Distribution Feeders	7

The new criteria will be scaled in over a 15-year period, and initially, will be applied to new installations and/or significant rebuilds initially. The criteria shall be reviewed and refined further, as needed, to reflect any major changes in standards or operating criteria.

2.0 PLANNING CRITERIA SUMMARY

The planning criteria are used to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA"). The planning criteria are a critical input to identifying system deficiencies in Liberty's distribution planning process. See Figure 1 for the planning process. The planning criteria described

[1] Attachment B provides a summary of the changes to Liberty's new criteria from the previous criteria under National Grid.

in this document provides the framework to identify normal and emergency conditions, the acceptable equipment ratings under these conditions, and the corrective action required when the criteria is exceeded. For normal loading conditions, the planning criteria are based on feeders and transformers to remain within 75% of normal ratings at all times and supply lines to remain within 90% of normal ratings at all times.

For N-1 contingency situations, the planning criteria is based on interrupted load returning to service via system reconfiguration through switching, installation of temporary equipment, such as mobile transformers or generators, and/or by repair of a failed device. Where practical, at least three feeder ties are planned for each feeder for switching flexibility and are integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Table 3 shall guide planning on the distribution system:

Table 3. Distribution System Design Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

3.0 DESCRIPTION OF THE DISTRIBUTION SYSTEM

Liberty's distribution system consists of lines and equipment operated at a voltage at or below 23 kilovolts ("kV"). The components of the distribution system include: distribution substations, sub-transmission lines, and distribution circuits or feeders.

3.1 Distribution Substations

The distribution substations within Liberty Utilities are a mixture of stations with one, two or three or more transformers. A typical substation consists of 23/13 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders. Some distribution substations are supplied by the 115 kV circuits and are jointly owned by Liberty Utilities and National Grid. Liberty Utilities and National Grid maintain approximately 16 distribution substations containing approximately 26 power transformers in the Liberty

Utilities' service territory. Liberty Utilities anticipates that the distribution planning criteria will, in general, be applied to both Liberty and New England Power assets serving Liberty customers, however all 115kV transformers serving Liberty customers are owned and maintained by National Grid. System Non-Wires and Wires solution alternatives will be developed along the lines of these criteria recognizing, however, the unique nature of transmission supply contingencies on the distribution system.

3.2 Sub-Transmission System

The sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are considered neither bulk transmission nor distribution. The voltages for Liberty's sub transmission system include 23 and 13.8 kV. The voltages for National Grid sub transmission system include 46 kV. The sub-transmission system is designed in an open loop or "radial" system and generally provides a redundant supply for distribution substations. The sub-transmission system is presently designed with conductors ranging from 336.4 ACSR to 1113 thousand circular mils ("kcmil") overhead conductors and from 500 to parallel 1000 kcmil copper underground conductor. There are eight sub-transmission lines that are maintained by Liberty Utilities.

3.3 Distribution Feeders

The distribution feeders from each substation are in a "radial" configuration with provisions for manual or automatic transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductors. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline and fuses and trip savers on the branch circuits. The Liberty Utilities distribution system is comprised of approximately 41 feeders ranging from 2.4kV to 13.2kV.

4.0 EQUIPMENT RATINGS

Thermal limits are recognized for all system elements in conducting planning studies. Current in equipment and lines are limited so that voltage drops are held to reasonable values; so that conductors will not be severely annealed or damaged; so that switches, connectors, etc. will not be overloaded and that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures, 2) load cycles, 3) wind velocities, and 4) potential loss of life of equipment.

Liberty's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

4.1 Overhead Conductors

The current carrying capacity (also known as, "ampacity") of an overhead conductor may be limited either by conductor clearances or maximum allowable operating temperature under a predefined set of reasonably severe summer or winter ambient conditions. The Company's Overhead Construction Standards book lists maximum ratings not to be exceeded for each conductor for normal and emergency operation.

As part of system operation, standard conductor sizes for overhead distribution construction of #2 AAAC, 1/0 AAAC and 477 AAAC or equivalent tree wire have been selected by Liberty Utilities.

The following general guidelines were developed for 13.2 kV overhead distribution lines:

- New single-phase overhead distribution lines should be constructed with #1/0 AAAC and new single-phase underground distribution lines should be constructed with #1/0 AL for loads less than 500kW.
- The single-phase lines should be reconductored to three-phase wherever needed based on operating conditions, phase imbalance and voltage drop.
- New three-phase overhead distribution lines and/or future distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:
    - For loads less than 3,000 kW: 1/0 AAAC
    - For loads greater than 3,000 kW: 477 AAAC
- The single-phase and three phase lines should be reconductored with covered tree conductor or spacer cable wherever needed based on operating conditions in tree prone areas.

The maximum ampacity of an overhead conductor is estimated for Normal (continuous) and Long-Time Emergency (LTE) operations for summer and winter conditions.

4.1.1 Normal Capability

The Normal rating shall be interpreted as the maximum value for normal peak loads on all new and rebuilt feeders. This is done to accommodate emergency conditions where ampacity may be increased for a period of time no greater than 24 hours. The temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, and covered conductors.

4.1.2 Long-Time Emergency Capabilities (24 hours)

The LTE rating shall be interpreted as the absolute maximum ampacity allowed for a given conductor. This ampacity should not be exceeded at any time unless an appropriate engineering review has been conducted. The temperature limit for LTE for 100% ampacity for operating conductor at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, and covered conductors.

4.1.3 **Short-Time Emergency Capability (As needed)**

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are typically less than 15 minutes in duration.

4.2 Underground Cables

Underground distribution line ratings were derived from the October 1957 AIEE paper entitled "The Calculation of the Temperature Rise and Load Capability of Cable System" by J.H. Neher and M.H. McGrath. These calculations integrate all aspects of the cable system design such as conductor material, conductor size, insulation, properties, insulation thickness, cable type, shield connections, load characteristics, installation conditions and environment. Cable ampacities are based on normal and emergency operating conditions. Normal cable ampacities are based on a 90° insulation operating temperature while emergency cable ampacities are based on 130° insulation operating temperature. The Company's underground construction standards book provides estimates of cable ampacity for common sizes and configuration of main line cables. Given the many different aspects of a cable system, specific cable ratings are typically derived using computer software such as Synergee Electric or PC Amp.

New three-phase underground distribution lines or future three-phase underground distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:

- For loads less than 1000 kW: #1/0 AL
- For loads greater than 1000 kW: 500 MCM CU
- For feeder cable getaways: 1000 MCM CU

Ampacities are defined for underground cables as follows:

4.2.1 **Normal Ampacity (Continuous)**

This is the maximum loading on the cable that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle.

4.2.2 **100-300 Hour Ampacity (LTE)**

This is the maximum emergency loading on the cable that does not cause the conductor temperature to exceed its applicable emergency value over a period of several consecutive 24-hour load cycles. At the end of the emergency time period, the load on the cable must be reduced to a value within its normal ampacity.

4.2.3 **One-Hour to 24-Hour Emergency Ampacities (STE)**

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are the maximum emergency loadings on the cable that do not cause the conductor temperature to exceed its allowable emergency value at any time during the period. At the end of the emergency time period, the load on the cable must be reduced so that the peak load in the next load cycle does not exceed the LTE ampacity (defined above).

4.3 Transformers

Distribution substation transformers are rated for loading according to the American National Standards Institute ("ANSI") standards for maximum internal hot spot and top oil temperatures. This is detailed in the Institute of Electrical and Electronics Engineers ("IEEE") Guide for Loading Mineral-Oil-Immersed Power Transformers up to and including 100 MVA with 55°C, or 65°C, winding temperature rise (ANSI/IEEE C57.91 latest version). The manufacturer's factory test data and the experienced 24-hour loading curve data are used in an iterative computer program that calculates allowable loading levels.

The transformer's "ratings" for the Normal ("N"), Long Term Emergency ("LTE"), and Short Term Emergency ("STE") load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer's life caused by its operation at the criteria temperatures for a specified duration, and on a defined load curve. Three categories of transformer capabilities are defined below:

4.3.1 Normal Capability

Winter normal and summer normal capabilities are based on a normal daily load cycle and on the maximum 24-hour average ambient temperature for the period involved. The maximum load for Normal operation of the transformer is determined and set when the operation of the transformer at that level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or the Top Oil Temperature exceeds 110 °C, or the Hot Spot Copper temperature exceeds 180 °C. Conditions above any of these limitations will result in a shortening of the transformer service life beyond prescribed design levels and/or physical damage to the equipment.

4.3.2 Long-Time Emergency Capabilities (1 hour to 300 hours)

These capabilities are based on a normal daily load cycle, with the emergency load increment added. The maximum 24-hour average ambient temperature is used for the appropriate season. The LTE rating of a substation transformer is determined and set when the 24 hour operation of the transformer, with that additional load in each of the hours in the 24 hour load cycle curve, causes a cumulative (24 hour) 3.0% loss of transformer life or the Top Oil temperature to exceed 130 °C, or the hot spot copper temperature to exceed 180 °C.

4.3.3 Short-Time Emergency Capability (15 minutes or less)

The STE rating of a transformer is determined and set when the one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (i.e., 24 hour) 3.0% Loss of

Transformer Life or a hot spot copper temperature exceeding 180°C. However, the maximum STE rating is limited to a value equal to twice the transformer's "nameplate" rating (i.e., 200%).

4.4 Other Equipment

In addition to the items above, normal and emergency capabilities are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers. Emergency capabilities usually involve elevated temperatures with some potential loss of equipment life. However, any circuit rating may be limited by other circuit equipment such as circuit breakers, disconnects, regulators, et cetera. These ratings are generally based on the allowable maximum temperature of the equipment. The facility (feeder, sub transmission line, and/or transformer) rating is determined by identifying the "limiting device" and applying the rating criteria for that device or equipment.

4.4.1 **Distribution Overhead Transformers**

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
145%	180%	160%	200%

4.4.2 **Distribution Single Phase Padmount Transformers**

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
140%	160%	140%	160%

4.4.3 **Distribution Three Phase Padmount**

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
110%	110%	110%	110%

4.4.4 Distribution Step-Down Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
110%	110%	110%	110%

4.4.5 **Circuit Breakers**

The following generic ratings in % of nameplate are used: NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
107%	123%	115%	130%

4.4.6 **Voltage Regulators**

The following generic regulator ratings in % of nameplate for 10% regulation are used:

55ºC INSULATION SYSTEM				**65ºC INSULATION SYSTEM**			
NORMAL		EMERGENCY		NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
125%	148%	125%	148%	141%	160%	141%	160%

4.4.7 **Disconnect Switches**

The following generic air switches ratings in % of nameplate:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
113%	134%	139%	147%

4.5 Equipment Rating Criteria Summary

The major equipment ratings to be used by planning engineers relate to transformers, overhead lines and underground cables. The normal and LTE rating limits for feeders, sub transmission lines and transformers may be applied for the time associated with each rating. Table 4 summarizes the durations for emergency loading that system operators must be aware of including the limiting factor involved in any contingency. There is also a short time emergency (STE) rating that is mainly used for transformers and must not exceed

200% of nameplate rating. Table 5 summarizes the Equipment Rating criteria, as described in more detail above.

Table 4. Facility Rating Durations

Equipment	Normal	LTE	STE
Feeders	Continuous	24 Hours	As Needed
Sub Transmission lines	Continuous	24 Hours	As Needed
Transformer	Continuous	1 - 300 Hours	15 Minutes

Table 5. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**
Normal	Continuous	• The maximum value for normal peak loads on all new and rebuilt feeders • Temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, & covered conductors	Continuous	• Maximum loading that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle • Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	• Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or • The Top Oil Temperature exceeds 110 °C, or • The Hot Spot Copper temperature exceeds 180 °C
LTE	24 Hours	• The absolute maximum ampacity allowed for a given conductor and should not be exceeded at any time. • Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, & covered conductors	100 - 300 Hours	• Maximum loading that does not cause the conductor temperature to exceed its design value over several consecutive 24-hour load cycles. • Emergency cable ampacities are based on 130° insulation operating temperature.	1 - 300 Hours	• Level for the peak hour with the emergency load added in the 24-hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer life, or • the Top Oil Temperature exceeds 130 °C, or • the Hot Spot Copper temperature exceeds 180 °C
STE	As Needed	• Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	• Maximum loading that does not cause the conductor temperature to exceed its allowable emergency value at any time during a 24-hour load cycle. • Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	• The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer Life, or • a hot spot copper temperature exceeding 180°C. • Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

5.0 DISTRIBUTION SUBSTATION TRANSFORMER LOADING CRITERIA

The ratings of transformers are calculated from their thermal heat transfer characteristics and the expected electric loading experience over a 24-hour cycle. All distribution substation transformer bank ratings are evaluated seasonally for their summer and winter values.

5.1 Normal Operation Design Criteria

Normal operation is the condition under which all-electric infrastructure equipment is fully functional. A substation transformer will not be loaded above 75% of its Normal rating during non-contingency operating periods.

5.2 First Contingency Emergency Design Criteria

First contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. For first contingency emergency conditions involving the loss of one distribution substation transformer in an existing two-bank or more configuration, the following system design criteria applies:

- In cases where a first contingency situation causes the LTE rating of the remaining transformer to be exceeded, all load above the LTE rating of the remaining transformers must be transferred to neighboring facilities or shed 15 minutes without exceeding the LTE rating of the substation transformers or distribution circuits receiving the load.
- In cases where a first contingency situation will cause the STE rating of a remaining transformer to be exceeded, load must be immediately reduced (dropped/shed) to a level within the STE. All load between the LTE and STE ratings, and any load that was initially shed to get the remaining transformer below its STE rating, must be transferred to peripheral facilities without exceeding the LTE rating of the substation transformers or the distribution circuits receiving the load.
- Repairs or the installation of mobile equipment are expected to require at least a 24 hour implementation.
- For a typical Liberty owned substation consisting of 9.375 MVA transformers, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5 MW. If more than 60MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts and the cost to mitigate.

5.3 Automatic Transfer of Load

Locations with two or more transformers at a substation utilize automatic bus transfers. Based on the loading limitations on Section 5.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during a first contingency. Cases where automatic restoration is disabled will be communicated with Electric Control as part of an annual summer preparedness review. Disabling of automatic bus transfer schemes will not be considered as a permanent solution to a criteria violation.

6.0 DISTRIBUTION CIRCUIT LOADING CRITERIA

6.1 Normal Operation Design Criteria

A feeder circuit should be loaded to no more than 75% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions and/or provides capacity to serve new business or commercial applications in a timely manner.

After 75% loading is reached, unacceptable voltage levels are often experienced on tap lines and at the end of the feeder.

6.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a distribution circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. For the loss of a distribution feeder, the following criterion applies:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies. In general, and whenever practical, each feeder should have three feeder ties to neighboring feeders.
- Distribution feeders should be limited to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or 2,000kVA of load between disconnecting devices.
- After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. All adjoining tie feeders can be loaded to their maximum LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- If more than 16 MWh of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- For a typical Liberty owned 10 MW feeder, approximately 8 MW would need to be restored via switching within one hour. The remaining 2 MW would be restored after

repairs within 4 hours. Where longer repair times are needed such as for a cable getaway fault, the load out of service should be reduced to 1 MW.

6.3 Automatic transfer on feeders

In some cases it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers or due to automatic reclosing loop schemes in the distribution lines.

6.4 Primary Circuit Voltage Criteria

The normal and emergency voltage to all customers shall be in line with limits specified by the state of NH and within the limits of ANSI C84.1-2006.

These upper and lower voltage ANSI limits, as measured at the customer's meter, are listed below in Table 6:

Table 6. Voltage Requirements for LU

For 120 V – 600 V Systems				
Nominal Voltage (V)	**Service Voltage (V)**			
	Range A		**Range B**	
	Max	Min	Max	Min
120	126	114	127	110
240	252	228	254	220
480	504	456	508	440

Source: ANSI

Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or pad mounted line regulators.

Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 7 above are maintained. The ultimate goal is to keep all customers' service voltages within accepted limits. From a supply point of view, the acceptability of voltage regulation is determined at the distribution substation buses. At substations with feeder or bus regulating equipment, the regulation (the extreme range of voltages expressed as a percentage of normal peak load voltage) should be no greater than 10 percent for normal and 15 percent for emergency conditions on the source side of the regulating equipment. Most

I. PURPOSE

To establish a procedure for calculating the seasonal **Peak Load Forecast** for each of the **loadflow** areas and the PSNH system.

II. AREAS/PERSONS AFFECTED

This procedure applies to or affects:

- PSNH System Planning and Strategy

III. POLICY

It is the policy of PSNH to develop a peak load forecast each year after the summer and winter annual **Peak Load** is achieved. It is intended that this procedure be followed to provide a consistent practice of developing a **Peak Load Forecast** using historical data, known **block load** changes and engineering judgment.

IV. DEFINITIONS

A. **Adjusted Growth Rate (AGR) –** The Compound Growth Rate (CGR) adjusted with input from Field Engineering.

B. **Area Peak Load Tables -** Excel spreadsheets containing historical area **Peak Loads** and Summer and Winter **Peak Load Forecasts** for the next ten years.

C. **Block Loads** – Load changes which may add to or subtract from the forecasted load level for the study area. Additive **Block Loads** are known large industrial customers, blocks of commercial growth, and support of **Rate B customers**. Subtractive **Block Loads** include industrial customer closings.

D. **Compound Growth Rate (CGR)** – The calculation of the peak load growth rate, on average, over a 10 year period based on historical peaks.

E. **Degree Days** - A degree day compares the outdoor mean daily temperature to a standard of 65 degrees Fahrenheit (F).

F. **ESCC** – Electric System Control Center.

G. **Heat wave** – Multiple contiguous days during the summer with cooling **Degree Days** of 17 or higher.

H. **Load Forecast Folder** – K drive folder set up for each study done. This is located at “K:\Deptdata\Energy Delivery\System Plan&Strategy\Load Forecasts” and designated with the year of the forecast calculation.

I. **Loadflow** – The PSS/E computer model of the PSNH electric distribution system.

J. **Loadflow Area** – The 12 different geographical areas modeled in the **Loadflow**.

K. **Peak Load Forecast** – The highest hourly summer and winter load level that is projected to occur in future years.

L. **Peak Load** – The annual highest historical hourly load level achieved during the previous years for summer and winter.

M. **Projected Growth Rate (PGR)** – The annual growth rate that is projected to occur in the future years.

N. **PSNH System** – PSNH defined zones in the **Loadflow**. The **Loadflow** defines the 34.5kV and below system as zones 2 – 8 and 10 - 12. (Zones 9 & 13 are Unitil.)

O. **PI System** – Database of historical operating data which connects the user to the **ESCC** historical load database using Microsoft Excel. This is used for gathering data on distribution loads including 34.5 kV transformers and lines.

P. **Rate B Customer** – A customer with generation that offsets its own load but requires PSNH to have the capability of serving its entire load when generation is out of service.

V. SAFETY MANUAL

No	Should a copy of this procedure be inserted into the functional area's safety and health handbook?

VI. OVERVIEW

The intent of this procedure is to define the steps required to develop 10 year summer and winter **Peak Load Forecasts.**

This process is used to calculate a peak load forecast for each of PSNH's geographical **Loadflow Areas** and the **PSNH System**. Unitil provides forecast information for its **Loadflow Areas** and is included in the **Peak Load Forecast**.

VII. PERIODIC REVIEW OF GUIDELINE

The Procedure Owner is responsible for maintaining this guideline and keeping current with good engineering design practices. The Procedure Owner for this Energy Delivery Procedure is the Manager of System Planning and Strategy.

Annually, the Procedure Owner shall review the design guideline for conformance to standard engineering practices and industry criteria to determine if the guideline shall be revised, rewritten, or cancelled.

As required, the Procedure Owner shall recommend changes to the Director of Energy Delivery. If approved by the Director, the Procedure Owner shall change the Procedure in accordance with AP-2001 Writing and Publishing Procedures.

VIII. PROCEDURE

A. Identify Current Year Area Peaks

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Copy last year's folder and update the name to include the new year. This folder is located in "K:\Deptdata\Energy Delivery\System Plan&Strategy\Load Forecast\". The naming format is 'YYYY Summer Forecast', for the summer forecast and 'YYYY-YY Winter Forecast', for the winter. (The new folder is the folder you will be working with for the rest of this procedure).
System Planning & Strategy	2.	Open "Current Summer System Loading.xls" Shown in (APPENDIX A) for summer loading and "Current Winter System Loading.xls" for winter loading.
System Planning & Strategy	3.	On this loading spreadsheet, update the start and end dates for each month. Only the year should be changed. Note: after the date has been updated 'F9' must be pressed to update the data. (This will download monthly peak load data from PI, for each area)
System Planning & Strategy	4.	Verify the daily data to make sure it corresponds with the rest of the days in the month. (Invalid data can be received; change the invalid data font to red and ignore these values). If you question the value verify it with the ESCC and/or the Circuit Owner.
System Planning & Strategy	5.	Identify the peak load for each area by updating the formula in the 'Monthly Maximum' row to exclude invalid data (Appendix A).
System Planning & Strategy	6.	Verify the configuration of each area at the time of the area's peak with the ESCC and/or the Circuit Owner.
System Planning & Strategy	7.	Adjust the area peak load if necessary by adding or subtracting load that was switched to another area at the time of peak.

System Planning & Strategy	8.	Identify the season's maximum for each area. Winter months are: December, January, February, and March. Summer months are June, July, and August.
System Planning & Strategy	9.	If the **AREA** peak for the current year is a new historical system peak, then this is used to develop the new **Loadflow Area** and **PSNH System** forecasts. Skip Step 10 and continue to Section B.
System Planning & Strategy	10.	If the current year's peak is not a new historical peak, then the 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.

EXCEPTIONS

a. If the 5 year historical peak is prior to the last year with consecutive days of 17 cooling degree days, use the last year with consecutive days of 17 cooling degree days as the 5 year historical peak year.
b. If the 5 year historical peak is after the last year with consecutive days of 17 cooling degree days, use the data from the year that yields the larger forecasted value.

B. Update PSNH System Current Year Loads

RESPONSIBILITY		ACTION
Marketing Support	1.	The Load Research Group in the Marketing Support Department calculates the load in MWH at the time, hour, and day of the current year's peak at "PSNH Delivered Peak Load" report.
System Planning & Strategy	2.	Open the previous years forecast "YYYY-YY Winter Forecast.xls" for winter and "YYYY Summer Forecast.xls" for summer. Save the file using the current year in the 'Y' locations. Notice there are multiple tabs. Press the tab to bring up the sheet titled "Peak_Loads". (Appendix B).

System Planning & Strategy	3.	Insert a line underneath the last year's data and follow the format of the previous year, inputting each area's new peak, calculated in Sections A. (Appendix C).
System Planning & Strategy	4.	From the Marketing Support Department's "PSNH Delivered Peak Load Report", insert the value "PSNH Peak Load Including NHEC, Ashland, New Hampton and Wolfeboro Wholesale Loads Excludes AES OFFLINE SS Excludes CVEC Load" in the **Area Peak Load Table** in the current year PSNH **Peak Load** cell.
System Planning & Strategy	5.	If the year had multiple consecutive 17 cooling **Degree Days**, shade the rows light gray as done in previous years. Cooling **Degree Day** information is located at 'K:\Deptdata\Energy Delivery\System Plan&Strategy\Load ForecastsCDD_ALLYEARS.xls'

C. Incorporate Unitil System Forecast

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Include in **Area Peak Load Tables** the peak load forecast for UES/Capital and UES/Seacoast areas provided by UES. **UES/Capital** – The Unitil Electric region that serves the Concord area. **UES/Seacoast** – The Unitil Electric region on the Seacoast including Hampton, Exeter, Seabrook, Kingston, etc.

D. Update PSNH Area Peak Load Forecasts

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Calculate the percent difference (% Difference). This can be done by copying and pasting the formula in the above cell. (Appendix D). The formula is: $\left(\frac{CurrentYear}{PreviousYear}\right)-1$

System Planning & Strategy	2.	Calculate the Compound Growth Rate (CGR). (Appendix E). The formula is: $$CGR = \left[\left(\frac{5YearHistorPk}{10YrOldPk} \right)^{\frac{1}{x}} - 1 \right]$$ X=PkYr-10YrPkYr Note: If the 10 year old peak is a low point compared to the surrounding peaks, adjust the 10 year 'look back time' to 11 years based on the higher peak and then update formula. (Appendix F).
System Planning & Engineering	3.	Update the Adjusted Growth Rate (AGR). This is done based on the Compound Growth Rate (CGR) and with input from circuit owners and Division Field Engineering Managers.
System Planning & Strategy	4.	Update the Projected Growth Rate (PGR). This is done based on rounding the CGR up to the next 0.25%. (Note: Minimum PGR is 0.5%.)
System Planning & Strategy	5.	Update the next year's peak. (Appendix G). The following equation: $NxtYrPk = (5YearHistorPk)(1 + AGR)^{NxtYr - 5YearHistorPkYr}$ <u>EXCEPTIONS</u> a. If the 5 year historical peak is prior to the last year with consecutive days of 17 cooling degree days, use the last year with consecutive days of 17 cooling degree days as the 5 year historical peak year. b. If the 5 year historical peak is after the last year with consecutive days of 17 cooling degree days, use the data from the year that yields the larger forecasted value.

System Planning & Strategy	7.	Update the forecast for the next 10 years. Adjust the first forecasted year in Column A to reflect the next year (Appendix C), all other years will automatically update. Calculate future peaks for years 2 – 5 (Appendix G) using the equation below: $$FuturePks(2-5) = (PreviousYrPk)(1+AGR)$$ Calculate the future peaks for years 6-10 using the following equation: $$FuturePks(6-10) = (PreviousYrPk)(1+PGR)$$
System Planning & Strategy	8.	Repeat sections D.1-D.7 for all Loadflow Areas & PSNH System.

E. Area Peak Load Graph Adjustment

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Update **AREA** by clicking on its tab. Notice each **AREA** has its own tab at the bottom of the **Area Peak Load Tables**.
System Planning & Engineering	2.	Enter the areas seasonal peak in its sheet. Add any new rows and copy the formulas from any existing rows into the new rows to maintain a 10 year projection. (Appendix H).
System Planning & Strategy	3.	Adjust the Low and High Annual Growth rates and analyze the sensitivity of the previously determined Projected Annual Growth Rate.
System Planning & Strategy	4.	Change the "Adjustable" percentage to ensure that the **PGR** accurately follows the envelope. If a better match is found update the **PGR**.

F. Finalize Peak Load Forecast

RESPONSIBILITY		ACTION
System Planning & Strategy	1.	Add and adjust spreadsheet notes to include pertinent information for the **Peak Load Forecast.**
System Planning & Strategy	2.	Save **Peak Load Forecast** in the **Load Forecast Folder**. Change spreadsheet properties to be a read-only file.
System Planning & Strategy	3.	Revise throughout the year as required, saving each update as a Revision.

IX ED-3029 REVISION HISTORY

Revision Number	Date	Reason
Rev 0	05/04/2007	Original issue
Rev 1	10/24/2007	Minor housekeeping Changes
Rev 2	05/06/2015	Complete Rework

X. APPENDICES

APPENDIX A
ACQUIRE PEAK LOAD INFORMATION

APPENDIX B
FORECAST SPREADSHEET OVERVIEW

APPENDIX C
RECORD PEAK LOAD INFORMATION

APPENDIX D
CALCULATE PERCENT DIFFERENCE

APPENDIX E
CALCULATE NEW COMPOUND GROWTH RATE (10 YEAR)

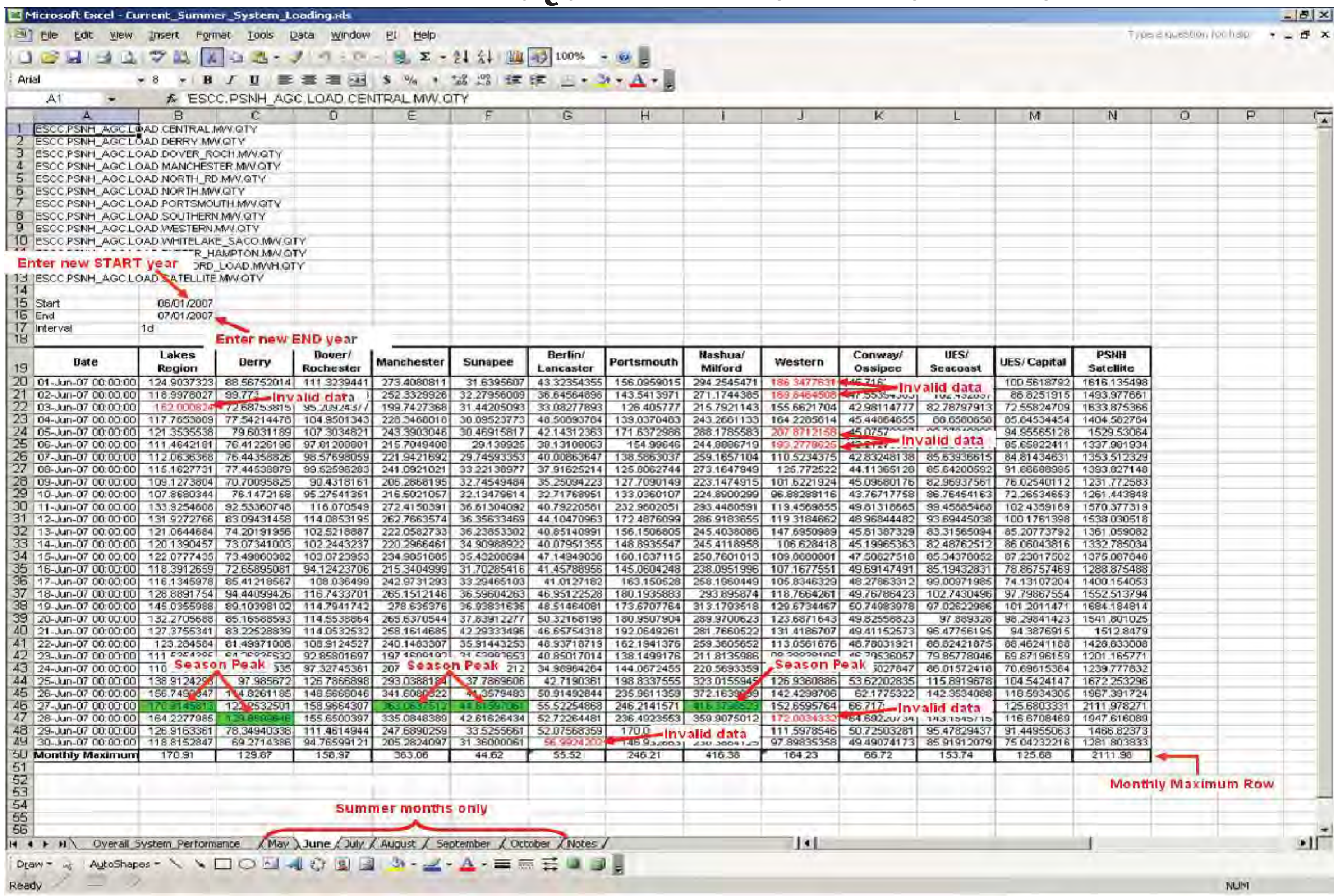
APPENDIX F
CALCULATE NEW COMPOUND GROWTH RATE (OTHER THAN 10 YEARS)

APPENDIX G
CALCULATE PROJECTED GROWTH

APPENDIX H

UPDATE AREA CHARTS AND GRAPHS

APPENDIX A – ACQUIRE PEAK LOAD INFORMATION

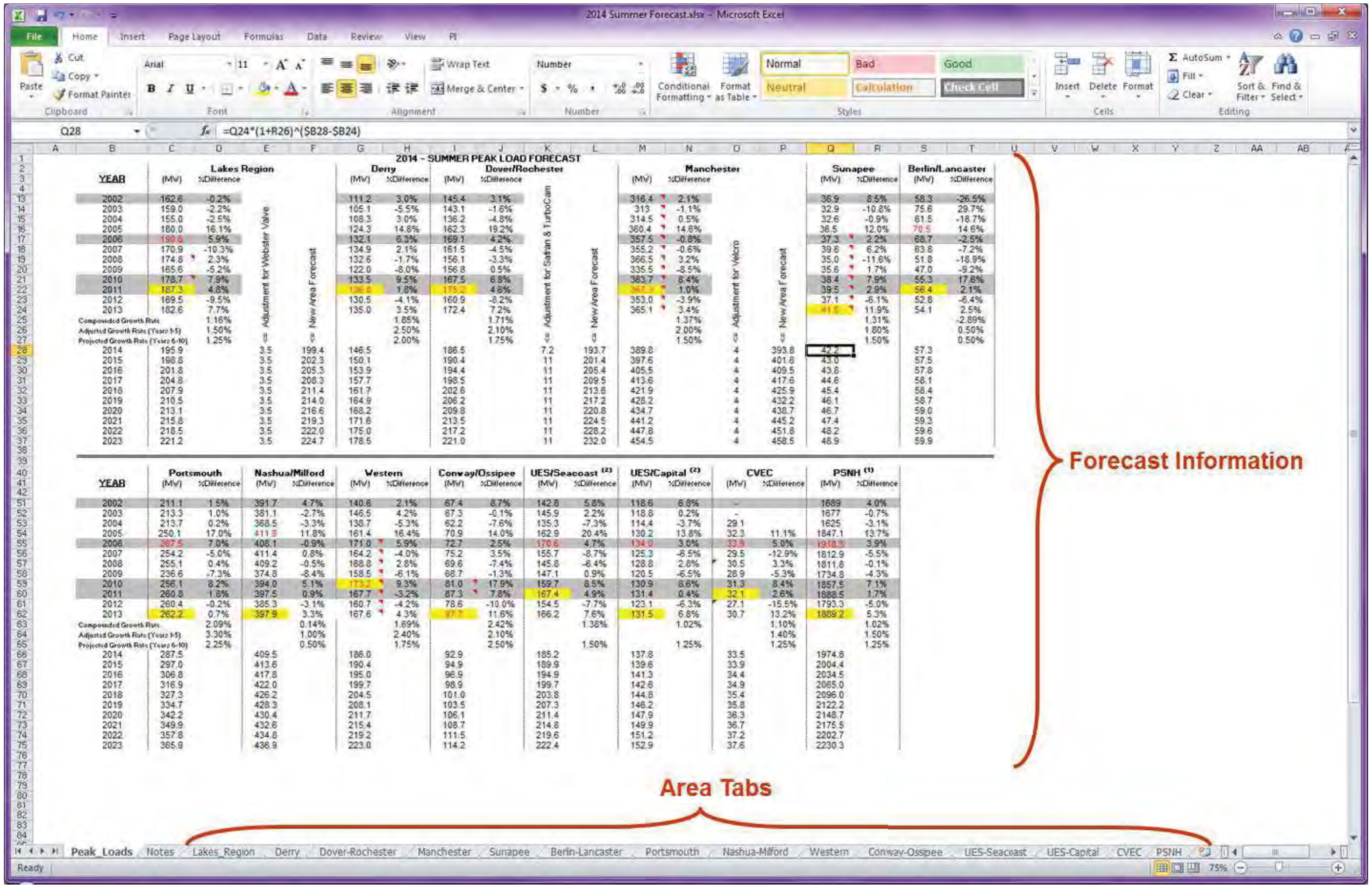


	A	B
1	ESCC.PSNH_AGC.LOAD.CENTRAL.MW.QTY	
2	ESCC.PSNH_AGC.LOAD.DERRY.MW.QTY	
3	ESCC.PSNH_AGC.LOAD.DOVER_ROCH.MW.QTY	
4	ESCC.PSNH_AGC.LOAD.MANCHESTER.MW.QTY	
5	ESCC.PSNH_AGC.LOAD.NORTH_RD.MW.QTY	
6	ESCC.PSNH_AGC.LOAD.NORTH.MW.QTY	
7	ESCC.PSNH_AGC.LOAD.PORTSMOUTH.MW.QTY	
8	ESCC.PSNH_AGC.LOAD.SOUTHERN.MW.QTY	
9	ESCC.PSNH_AGC.LOAD.WESTERN.MW.QTY	
10	ESCC.PSNH_AGC.LOAD.WHITELAKE_SACO.MW.QTY	
11	[illegible]R_HAMPTON.MW.QTY	
12	[illegible]ORD_LOAD.MWH.QTY	
13	ESCC.PSNH_AGC.LOAD.SATELLITE.MW.QTY	
14		
15	Start	06/01/2007
16	End	07/01/2007
17	Interval	1d
18		

	Date	Lakes Region	Derry	Dover/ Rochester	Manchester	Sunapee	Berlin/ Lancaster
20	01-Jun-07 00:00:00	124.9037323	88.56752014	111.3239441	273.4080811	31.6395607	43.32354355
21	02-Jun-07 00:00:00	118.9978027	99.773[illegible]	[illegible]	252.3329926	32.27956009	36.64564896
22	03-Jun-07 00:00:00	162.000824	72.68753815	95.209243[illegible]	199.7427368	31.44205093	33.08277893
23	04-Jun-07 00:00:00	117.7653809	77.54214478	104.9501343	228.3468018	30.09523773	48.50090764
24	05-Jun-07 00:00:00	121.3535538	79.6031189	107.3034821	243.3903046	30.46915817	42.14312363
25	06-Jun-07 00:00:00	111.4642181	76.41226196	97.61200801	215.7049408	29.139925	38.13108063
26	07-Jun-07 00:00:00	112.0636368	76.44358826	98.57698059	221.9421692	29.74593353	40.00863647
27	08-Jun-07 00:00:00	115.1627731	77.44538879	99.62596283	241.0921021	33.22138977	37.91625214
28	09-Jun-07 00:00:00	109.1273804	70.70095825	90.4318161	205.2868195	32.74549484	35.25094223
29	10-Jun-07 00:00:00	107.8680344	76.1472168	95.27541351	216.5021057	32.13479614	32.71768951
30	11-Jun-07 00:00:00	133.3254608	92.53360748	116.070549	272.4150391	36.61304092	40.79220581
31	12-Jun-07 00:00:00	131.9272766	83.09431458	114.0853195	262.7663574	36.35633469	44.10470963
32	13-Jun-07 00:00:00	121.0644684	74.20191956	102.5218887	222.0582733	36.23853302	40.65140991
33	14-Jun-07 00:00:00	120.1390457	73.07341003	102.2443237	220.2966461	34.90988922	40.07951355
34	15-Jun-07 00:00:00	122.0777435	73.49860382	103.0723953	234.9851685	35.43208694	47.14949036
35	16-Jun-07 00:00:00	118.3912659	72.65895081	94.12423706	215.3404999	31.70285416	41.45788956
36	17-Jun-07 00:00:00	116.1346978	85.41218567	108.036499	242.9731293	33.29465103	41.0127182
37	18-Jun-07 00:00:00	128.8891754	94.44099426	116.7433701	265.1512146	36.59604263	46.95122528
38	19-Jun-07 00:00:00	145.0355988	89.10398102	114.7941742	278.635376	36.93831635	48.51464081
39	20-Jun-07 00:00:00	132.2705688	85.16568593	114.5538864	265.6370544	37.63912277	50.32168198
40	21-Jun-07 00:00:00	127.3755341	83.22528839	114.0532532	258.1614685	42.29333496	46.65754318
41	22-Jun-07 00:00:00	123.284584	81.49971008	108.9124527	240.1483307	35.91443253	48.93718719
42	23-Jun-07 00:00:00	[illegible]	[illegible]	92.85801697	[illegible]	[illegible]	40.85017014
43	24-Jun-07 00:00:00	[illegible]	[illegible]	97.32745361	[illegible]	[illegible]	34.96964264
44	25-Jun-07 00:00:00	[illegible]	97.985672	126.7866898	[illegible]	37.7869606	42.7190361
45	26-Jun-07 00:00:00	[illegible]	[illegible]	148.5666046	[illegible]	[illegible]	50.91492844
46	27-Jun-07 00:00:00	[illegible]	[illegible]	158.9664307	[illegible]	[illegible]	55.52254868
47	28-Jun-07 00:00:00	164.2277985	[illegible]	155.6500397	335.0848389	42.61626434	52.72264481
48	29-Jun-07 00:00:00	126.9163361	78.34940338	111.4614944	247.6890259	33.5255661	52.07568359
49	30-Jun-07 00:00:00	118.8152847	69.2714386	94.76599121	205.2824097	31.36000061	56.9924202
50	Monthly Maximum	170.91	129.67	158.97	363.06	44.62	55.52

	Portsmouth	Nashua/ Milford	Western	Conway/ Ossipee	UES/ Seacoast	UES/ Capital	PSNH Satellite
20	156.0959015	294.2545471	186.3477631	[illegible]	[illegible]	100.5618792	1616.135498
21	143.5413971	271.1744385	169.8464508	[illegible]	[illegible]	86.8251915	1493.977661
22	126.405777	215.7921143	155.6621704	42.98114777	82.78797913	72.55824709	1633.875366
23	139.0370483	243.2661133	164.2285614	45.44664655	88.6560656	85.64534454	1404.582764
24	171.6372986	288.1785583	207.8712158	[illegible]	[illegible]	94.95565128	1529.53064
25	154.99646	244.8886719	193.2779625	[illegible]	[illegible]	85.65822411	1337.981934
26	138.5863037	259.1657104	110.5234375	42.83248138	85.63936615	84.81434631	1353.512329
27	125.8062744	273.1647949	125.772522	44.11365128	85.64200592	91.86688995	1393.827148
28	127.7090149	223.1474915	101.6221924	45.09680176	82.96937561	76.02540112	1231.772583
29	133.0360107	224.8900299	96.88288116	43.76717758	86.76454163	72.26534653	1261.443848
30	232.9602051	293.4480591	119.4569855	49.61318665	99.45685468	102.4359169	1570.377319
31	172.4876099	286.9183655	119.3184662	48.96844482	93.69445038	100.1761398	1538.030518
32	156.1506805	245.4038086	147.6950989	45.61387329	83.31565094	85.20773792	1361.059082
33	148.8935547	245.4118958	106.628418	45.19965363	82.48762512	86.06043816	1332.785034
34	160.1637115	250.7601013	109.8680801	47.50627518	85.34378052	87.23017502	1375.087646
35	145.0604248	238.0951996	107.1677551	49.69147491	85.19432831	78.86757469	1288.875488
36	163.150528	258.1960449	105.8346329	48.27863312	99.00971985	74.13107204	1400.154053
37	180.1935883	293.895874	118.7664261	49.76786423	102.7430496	97.79867554	1552.513794
38	173.6707764	313.1793518	129.6734467	50.74983978	97.02622986	101.2011471	1684.184814
39	180.9507904	289.9700623	123.6871643	49.82556823	97.889326	98.29841423	1541.801025
40	192.0649261	281.7660522	131.4186707	49.41152573	95.47756195	94.3876915	1512.8479
41	162.1941376	259.3605652	113.0561676	46.78031921	88.82421875	88.46241188	1428.833008
42	138.1499176	211.8135986	[illegible]	[illegible]	79.85778046	69.87196159	1201.165771
43	144.0672455	220.5693359	[illegible]	[illegible]	86.01572418	70.69615364	1239.777832
44	198.8337555	[illegible]	126.9360886	53.62202835	115.8919678	104.5424147	1672.253296
45	235.9611359	[illegible]	142.4298706	62.1775322	142.3534088	118.5934305	1967.391724
46	246.2141571	[illegible]	152.6595764	[illegible]	[illegible]	125.6803331	2111.978271
47	236.4923553	359.9075012	172.0034332	[illegible]	[illegible]	116.6708469	1947.616089
48	[illegible]	[illegible]	111.5978546	50.72503281	95.47829437	91.44955063	1466.82373
49	[illegible]	[illegible]	97.89835358	49.49074173	85.91912079	75.04232216	1281.803833
50	246.21	416.38	164.23	66.72	153.74	125.68	2111.98

APPENDIX B – FORECAST SPREADSHEET OVERVIEW



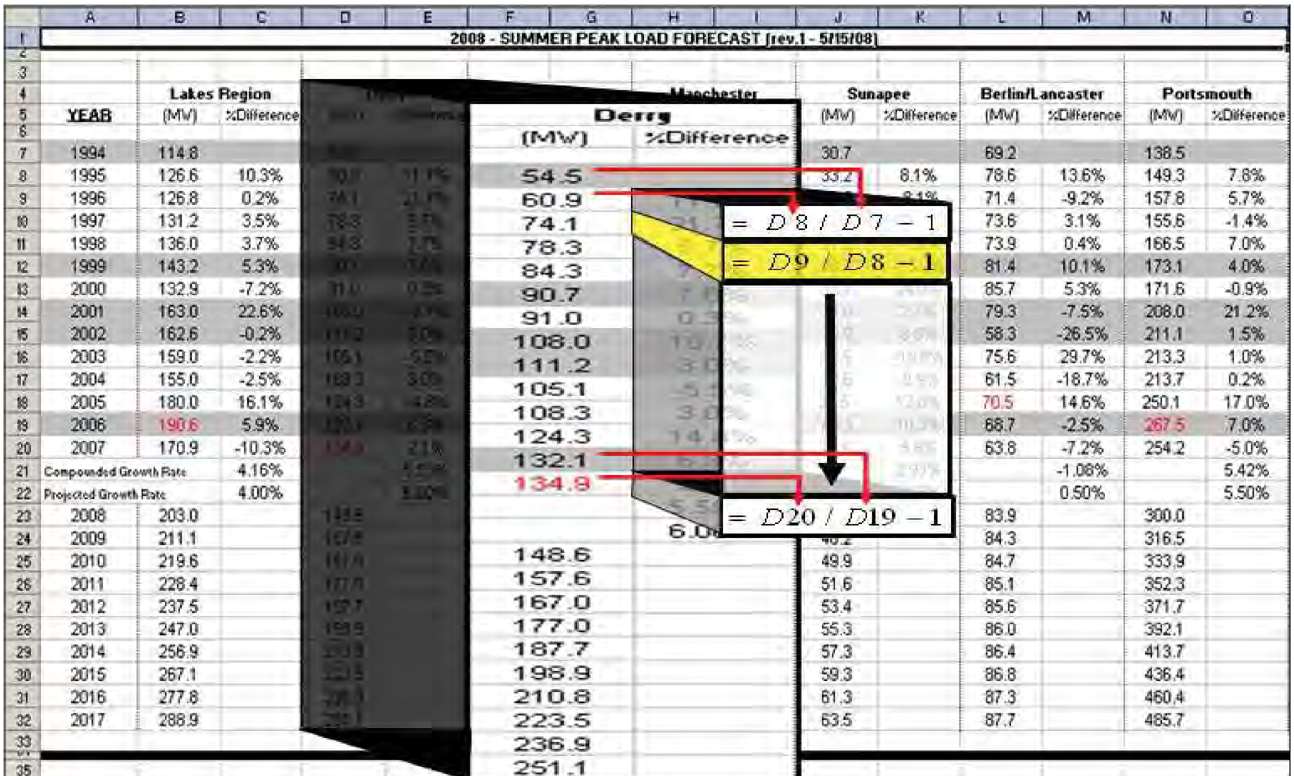
APPENDIX C – RECORD PEAK LOAD INFORMATION

2008 - SUMMER PEAK LOAD FORECAST (rev.1 - 5/15/08)

YEAR	Lakes Region (MW)	Lakes Region %Difference	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	Manchester (MW)	Manchester %Difference	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference	Portsmouth (MW)	Portsmouth %Difference
1994	114.8		54.5		116.3		237.7		30.7		69.2		138.5	
1995	126.6	10.3%	60.9	11.7%	116.1	-0.2%	244.6	2.9%	33.2	8.1%	78.6	13.6%	149.3	7.8%
1996	126.8	0.2%	74.1	21.7%	112.0	-3.5%	223.3	-8.7%	30.5	-8.1%	71.4	-9.2%	157.8	5.7%
1997	131.2	3.5%	78.3	5.7%	116.1	3.7%	246.7	10.5%	31.9	4.6%	73.6	3.1%	155.6	-1.4%
1998	136.0	3.7%	84.3	7.7%	113.7	-2.1%	262.9	6.6%	31.5	-1.3%	73.9	0.4%	166.5	7.0%
1999	143.2	5.3%	90.7	7.8%	118.7	4.4%	288.0	9.5%	26.7	-15.2%	81.4	10.1%	173.1	4.0%
2000	132.9	-7.2%	91.0	0.3%	119.5	0.7%	265.0	-8.0%	33.1	24.0%	85.7	5.3%	171.6	-0.9%
2001	163.0	22.6%	108.0	18.7%	141.0	18.0%	310.0	17.0%	34.0	2.7%	79.3	-7.5%	208.0	21.2%
2002	162.6	-0.2%	111.2	3.0%	145.4	3.1%	323.3	4.3%	36.9	8.5%	58.3	-26.5%	211.1	1.5%
2003	159.0	-2.2%	105.1	-5.5%	143.1	-1.6%	318.5	-1.5%	32.9	-10.8%	75.6	29.7%	213.3	1.0%
Added new line	5.0	-2.5%	108.3	3.0%	136.2	-4.8%	319.7	0.4%	32.6	-0.9%	61.5	-18.7%	213.7	0.2%
2005	180.0	16.1%	124.3	14.8%	162.3	19.2%	365.9	14.5%	36.5	12.0%	70.5	14.6%	250.1	17.0%
2006	190.6	5.9%	132.1	6.3%	169.1	4.2%	363.2	-0.7%	40.3	10.3%	68.7	-2.5%	267.5	7.0%
2007	170.9	-10.3%	134.9	2.1%	161.5	-4.5%	363.1	0.0%	42.6	5.8%	63.8	-7.2%	254.2	-5.0%
Compounded Growth Rate		4.16%		5.59%		3.48%		4.11%		2.93%		-1.08%		5.42%
Projected Growth Rate		4.00%		6.00%		3.00%		4.00%		3.50%		0.50%		5.50%
2008	203.0		148.6		170.5		407.3		46.6		83.9		300.0	
2009	211.1		157.6		175.6		423.6		48.2		84.3		316.5	
2010	219.6	Update year	167.0		180.9		440.5		49.9		84.7		333.9	
2011	228.4		177.0		186.3		458.1		51.6		85.1		352.3	
2012	237.5		187.7		191.9		476.5		53.4		85.6		371.7	
2013	247.0		198.9		197.7		495.5		55.3		86.0		392.1	
2014	256.9		210.8		203.6		515.3		57.3		86.4		413.7	
2015	267.1		223.5		209.7		535.9		59.3		86.8		436.4	
2016	277.8		236.9		216.0		557.4		61.3		87.3		460.4	
2017	288.9		251.1		222.5		579.7		63.5		87.7		485.7	

YEAR	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	Conway/Ossipee (MW)	Conway/Ossipee %Difference	UES/Seacoast (MW)	UES/Seacoast %Difference	UES/Capital (MW)	UES/Capital %Difference	CVEC (MW)	CVEC %Difference	PSNH [1] (MW)	PSNH [1] %Difference
1994	309.3		108.5		49.0		101.7		91.3				1291	
1995	307.2	-0.7%	109.0	0.5%	50.8	3.7%	106.2	4.4%	93.8	2.7%			1309	1.4%
1996	294.0	-4.3%	106.2	-2.6%	49.8	-2.0%	109.6	3.2%	95.8	2.1%			1266	-3.3%
1997	320.0	8.8%	117.7	10.8%	51.0	2.4%	111.6	1.8%	97.2	1.5%			1323	4.5%
1998	332.9	4.0%	125.8	6.9%	53.8	5.5%	115.2	3.2%	101.5	4.4%			1406	6.3%
1999	352.9	6.0%	128.9	2.5%	58.2	8.2%	118.8	3.1%	102.0	0.5%			1479	5.2%
2000	340.0	-3.7%	125.5	-2.7%	53.7	-7.7%	114.7	-3.5%	100.2	-1.8%			1447	-2.2%
2001	374.0	10.0%	137.7	9.7%	62.0	15.5%	135.0	17.7%	111.0	10.8%			1624	12.2%
2002	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%			1689	4.0%
2003	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%			1677	-0.7%
Added new line	8.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
2005	411.6	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
2006	408.1	-0.9%	168.0	4.1%	72.7	2.5%	164.32	0.9%	134.6	3.4%	33.9	5.0%	1918.3	3.9%
2007	411.4	0.8%	161.2	-4.1%	75.2	3.5%	155.30	-5.5%	126.1	-6.3%	29.5	-12.9%	1812.9	-5.5%
Compounded Growth Rate		2.64%		4.01%		3.96%		4.05%		3.34%		7.98%		3.54%
Projected Growth Rate		2.50%		3.70%		3.70%		4.00%		3.50%		3.50%		3.40%
2008	423.5		174.8		76.1		184.5		142.7		33.4		2021.7	
2009	434.1		181.3		78.9		191.1		146.3		34.5		2090.4	
2010		Update year	188.0		81.8		197.7		150.0		35.8		2161.5	
2011	456.0		194.9		84.8		204.3		153.6		37.0		2235.0	
2012	467.4		202.1		88.0		211.0		157.2		38.3		2310.9	
2013	479.1		209.6		91.2		217.7		160.9		39.6		2389.5	
2014	491.1		217.4		94.6		224.3		164.5		41.0		2470.8	
2015	503.4		225.4		98.1		231.0		168.2		42.5		2554.8	
2016	516.0		233.8		101.7		237.6		171.8		43.9		2641.6	
2017	526.9		242.4		105.5		244.3		175.5		45.5		2731.4	

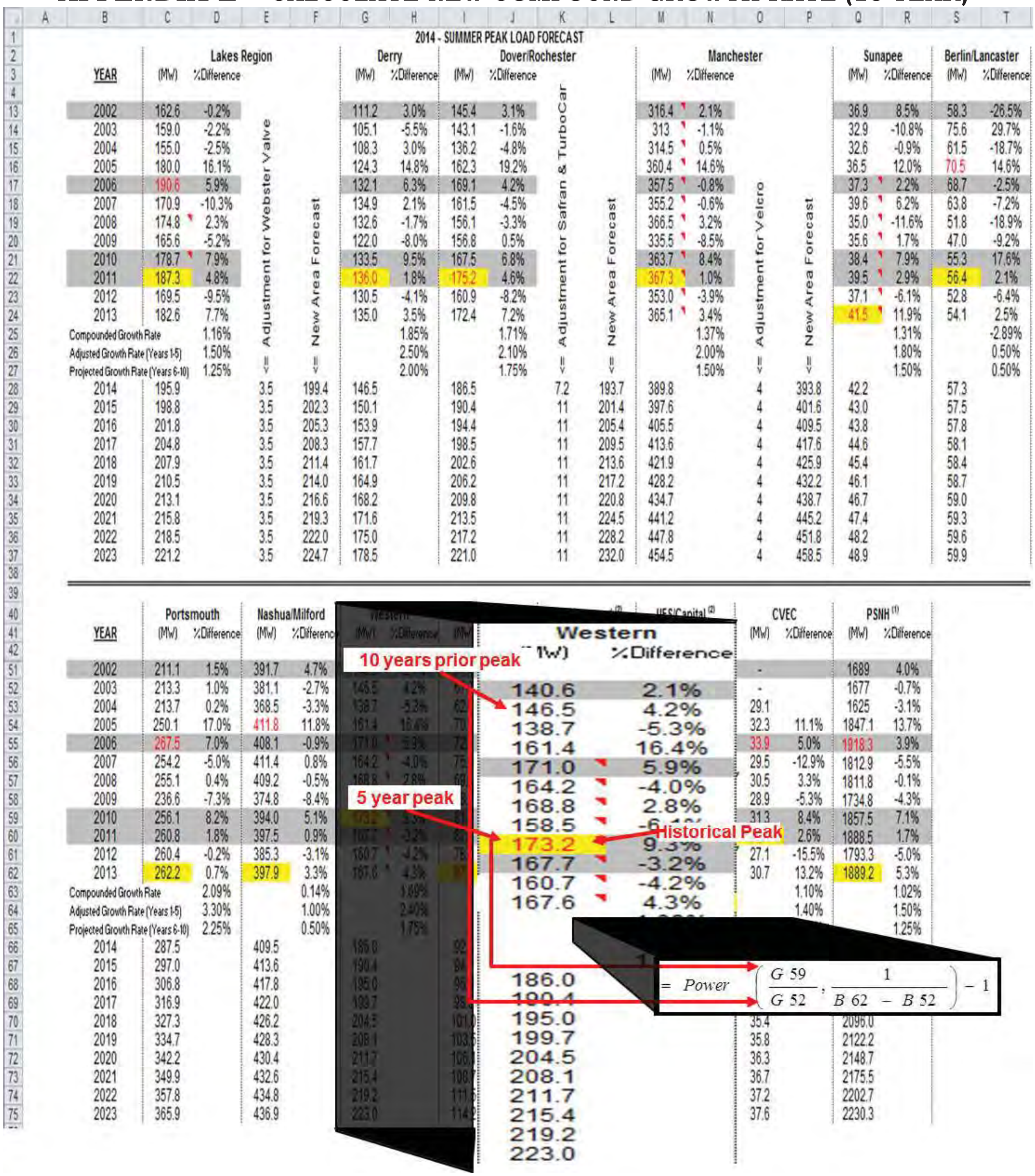
APPENDIX D – CALCULATE PERCENT DIFFERENCE



YEAR	Lakes Region (MW)	%Difference	Sunapee (MW)	%Difference	Berlin/Lancaster (MW)	%Difference	Portsmouth (MW)	%Difference
1994	114.8		30.7		69.2		138.5	
1995	126.6	10.3%	33.2	8.1%	78.6	13.6%	149.3	7.8%
1996	126.8	0.2%	[illegible]	[illegible]	71.4	-9.2%	157.8	5.7%
1997	131.2	3.5%	[illegible]	[illegible]	73.6	3.1%	155.6	-1.4%
1998	136.0	3.7%	[illegible]	[illegible]	73.9	0.4%	166.5	7.0%
1999	143.2	5.3%	[illegible]	[illegible]	81.4	10.1%	173.1	4.0%
2000	132.9	-7.2%	[illegible]	[illegible]	85.7	5.3%	171.6	-0.9%
2001	163.0	22.6%	[illegible]	[illegible]	79.3	-7.5%	208.0	21.2%
2002	162.6	-0.2%	[illegible]	[illegible]	58.3	-26.5%	211.1	1.5%
2003	159.0	-2.2%	[illegible]	[illegible]	75.6	29.7%	213.3	1.0%
2004	155.0	-2.5%	[illegible]	[illegible]	61.5	-18.7%	213.7	0.2%
2005	180.0	16.1%	[illegible]	[illegible]	70.5	14.6%	250.1	17.0%
2006	190.6	5.9%	[illegible]	[illegible]	68.7	-2.5%	267.5	7.0%
2007	170.9	-10.3%	[illegible]	[illegible]	63.8	-7.2%	254.2	-5.0%
Compounded Growth Rate		4.16%		[illegible]		-1.08%		5.42%
Projected Growth Rate		4.00%				0.50%		5.50%
2008	203.0		[illegible]		83.9		300.0	
2009	211.1		[illegible]		84.3		316.5	
2010	219.6		49.9		84.7		333.9	
2011	228.4		51.6		85.1		352.3	
2012	237.5		53.4		85.6		371.7	
2013	247.0		55.3		86.0		392.1	
2014	256.9		57.3		86.4		413.7	
2015	267.1		59.3		86.8		436.4	
2016	277.8		61.3		87.3		460.4	
2017	288.9		63.5		87.7		485.7	

YEAR	Nashua/Milford (MW)	%Difference	Western (MW)	%Difference	Conway/Ossipee (MW)	%Difference	UES/Seacoast (MW)	%Difference	UES/Capital (MW)	%Difference	CVEC (MW)	%Difference	PSNH [1] (MW)	%Difference
1994	309.3		108.5		49.0		101.7		91.3				1291	
1995	307.2	-0.7%	109.0	0.5%	50.8	3.7%	106.2	4.4%	93.8	2.7%			1309	1.4%
1996	294.0	-4.3%	106.2	-2.6%	49.8	-2.0%	109.6	3.2%	95.8	2.1%			1266	-3.3%
1997	320.0	8.8%	117.7	10.8%	51.0	2.4%	111.6	1.8%	97.2	1.5%			1323	4.5%
1998	332.9	4.0%	125.8	6.9%	53.8	5.5%	115.2	3.2%	101.5	4.4%			1406	6.3%
1999	352.9	6.0%	128.9	2.5%	58.2	8.2%	118.8	3.1%	102.0	0.5%			1479	5.2%
2000	340.0	-3.7%	125.5	-2.7%	53.7	-7.7%	114.7	-3.5%	100.2	-1.8%			1447	-2.2%
2001	374.0	10.0%	137.7	9.7%	62.0	15.5%	135.0	17.7%	111.0	10.8%			1624	12.2%
2002	391.7	4.7%	140.6	2.1%	67.4	8.7%	142.8	5.8%	118.6	6.8%			1689	4.0%
2003	381.1	-2.7%	146.5	4.2%	67.3	-0.1%	145.9	2.2%	118.8	0.2%			1677	-0.7%
2004	368.5	-3.3%	138.7	-5.3%	62.2	-7.6%	135.3	-7.3%	114.4	-3.7%	29.1		1625	-3.1%
2005	411.8	11.8%	161.4	16.4%	70.9	14.0%	162.9	20.4%	130.2	13.8%	32.3	11.1%	1847.1	13.7%
2006	408.1	-0.9%	168.0	4.1%	72.7	2.5%	164.32	0.9%	134.6	3.4%	33.9	5.0%	1918.3	3.9%
2007	411.4	0.8%	161.2	-4.1%	75.2	3.5%	155.30	-5.5%	126.1	-6.3%	29.5	-12.9%	1812.9	-5.5%
Compounded Growth Rate		2.64%		4.01%		3.96%		4.05%		3.34%		7.98%		3.54%
Projected Growth Rate		2.50%		3.70%		3.70%		4.00%		3.50%		3.50%		3.40%
2008	423.5		174.8		76.1		184.5		142.7		33.4		2021.7	
2009	434.1		181.3		78.9		191.1		146.3		34.5		2090.4	
2010	444.9		188.0		81.8		197.7		150.0		35.8		2161.5	
2011	456.0		194.9		84.8		204.3		153.6		37.0		2235.0	
2012	467.4		202.1		88.0		211.0		157.2		38.3		2310.9	
2013	479.1		209.6		91.2		217.7		160.9		39.6		2389.5	
2014	491.1		217.4		94.6		224.3		164.5		41.0		2470.8	
2015	503.4		225.4		98.1		231.0		168.2		42.5		2554.8	
2016	516.0		233.8		101.7		237.6		171.8		43.9		2641.8	
2017	528.9		242.4		105.5		244.3		175.5		45.5		2731.4	

APPENDIX E – CALCULATE NEW COMPOUND GROWTH RATE (10 YEAR)



2014 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	<== Adjustment for Webster Valve	<== New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	<== Adjustment for Safran & TurboCar	<== New Area Forecast	Manchester (MW)	Manchester %Difference	<== Adjustment for Velcro	<== New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	Portsmouth %Difference	Nashua/Milford (MW)	Nashua/Milford %Difference	Western (MW)	Western %Difference	CVEC (MW)	CVEC %Difference	PSNH[1] (MW)	PSNH[1] %Difference
2002	211.1	1.5%	391.7	4.7%	140.6	2.1%	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	146.5	4.2%	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	138.7	-5.3%	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	161.4	16.4%	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	171.0	5.9%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	164.2	-4.0%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	168.8	2.8%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	158.5	[illegible]	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	173.2	9.3%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	167.7	-3.2%	[illegible]	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	160.7	-4.2%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	167.6	4.3%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		0.14%		[illegible]		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		1.00%		[illegible]		1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		[illegible]		[illegible]		1.25%
2014	287.5		409.5		186.0		[illegible]		[illegible]	
2015	297.0		413.6		190.4		[illegible]		[illegible]	
2016	306.8		417.8		195.0		[illegible]		[illegible]	
2017	316.9		422.0		199.7		35.4		2096.0	
2018	327.3		426.2		204.5		35.8		2122.2	
2019	334.7		428.3		208.1		36.3		2148.7	
2020	342.2		430.4		211.7		36.7		2175.5	
2021	349.9		432.6		215.4		37.2		2202.7	
2022	357.8		434.8		219.2		37.6		2230.3	
2023	365.9		436.9		223.0					

APPENDIX F - CALCULATE NEW COMPOUND GROWTH RATE (OTHER THAN 10 YEARS)

2014 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	Lakes Region %Difference	Adjustment for Webster Valve	New Area Forecast	Derry (MW)	Derry %Difference	Dover/Rochester (MW)	Dover/Rochester %Difference	Adjustment for Safran & TurboCar	New Area Forecast	Manchester (MW)	Manchester %Difference	Adjustment for Velcro	New Area Forecast	Sunapee (MW)	Sunapee %Difference	Berlin/Lancaster (MW)	Berlin/Lancaster %Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%	<=	<=		2.00%		1.75%	<=	<=		1.50%	<=	<=		1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	Portsmouth %Difference	UES/Capital[2] (MW)	UES/Capital[2] %Difference	CVEC (MW)	CVEC %Difference	PSNH[1] (MW)	PSNH[1] %Difference
2002	211.1	1.5%	118.6	6.8%	-		1689	4.0%
2003	213.3	1.0%	[illegible]	[illegible]	[illegible]	[illegible]	1677	-0.7%
2004	213.7	0.2%	[illegible]	[illegible]	[illegible]	[illegible]	1625	-3.1%
2005	250.1	17.0%	[illegible]	[illegible]	[illegible]	11.1%	1847.1	13.7%
2006	267.5	7.0%	[illegible]	3.0%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	125.3	-6.5%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	128.8	2.8%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	120.5	-6.5%	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	130.9	8.6%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	131.4	0.4%	32.1	2.6%	1888.5	1.7%
2012	260.4	-0.2%	123.1	-6.3%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	131.5	6.8%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		1.02%		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		[illegible]		1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		[illegible]		1.25%		1.25%
2014	287.5		[illegible]		[illegible]		1974.8	
2015	297.0		[illegible]		[illegible]		[illegible]	
2016	306.8		[illegible]		[illegible]		[illegible]	
2017	316.9		[illegible]		[illegible]		[illegible]	
2018	327.3		144.8		35.4		2096.0	
2019	334.7		146.2		35.8		2122.2	
2020	342.2		147.9		36.3		2148.7	
2021	349.9		149.9		36.7		2175.5	
2022	357.8		151.2		37.2		2202.7	
2023	365.9		152.9		37.6		2230.3	

UES/Seacoast[2]

Nashua/Milford	%Difference
391.7	
381.1	
368.5	[illegible]
411.8	[illegible]
408.1	-0.9%
411.4	0.8%
409.2	-0.5%
374.8	-8.4%
394.0	5.1%
397.5	0.9%
385.3	-3.1%
397.9	3.3%
409.5	
413.6	
417.8	
422.0	
426.2	
428.3	
430.4	
432.6	
434.8	
436.9	

11 years prior peak

10 years prior peak

DO NOT USE (Low Point)

Historical Peak

5 year peak

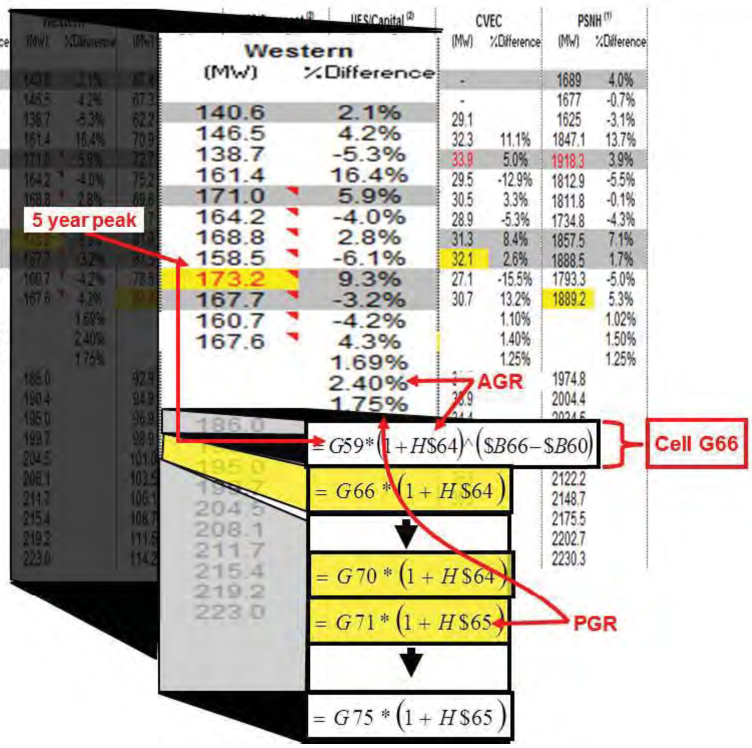
$$= Power\left(\frac{E\ 62}{E\ 51}; \frac{1}{B\ 62 - B\ 51}\right) - 1$$

APPENDIX G - CALCULATE PROJECTED GROWTH

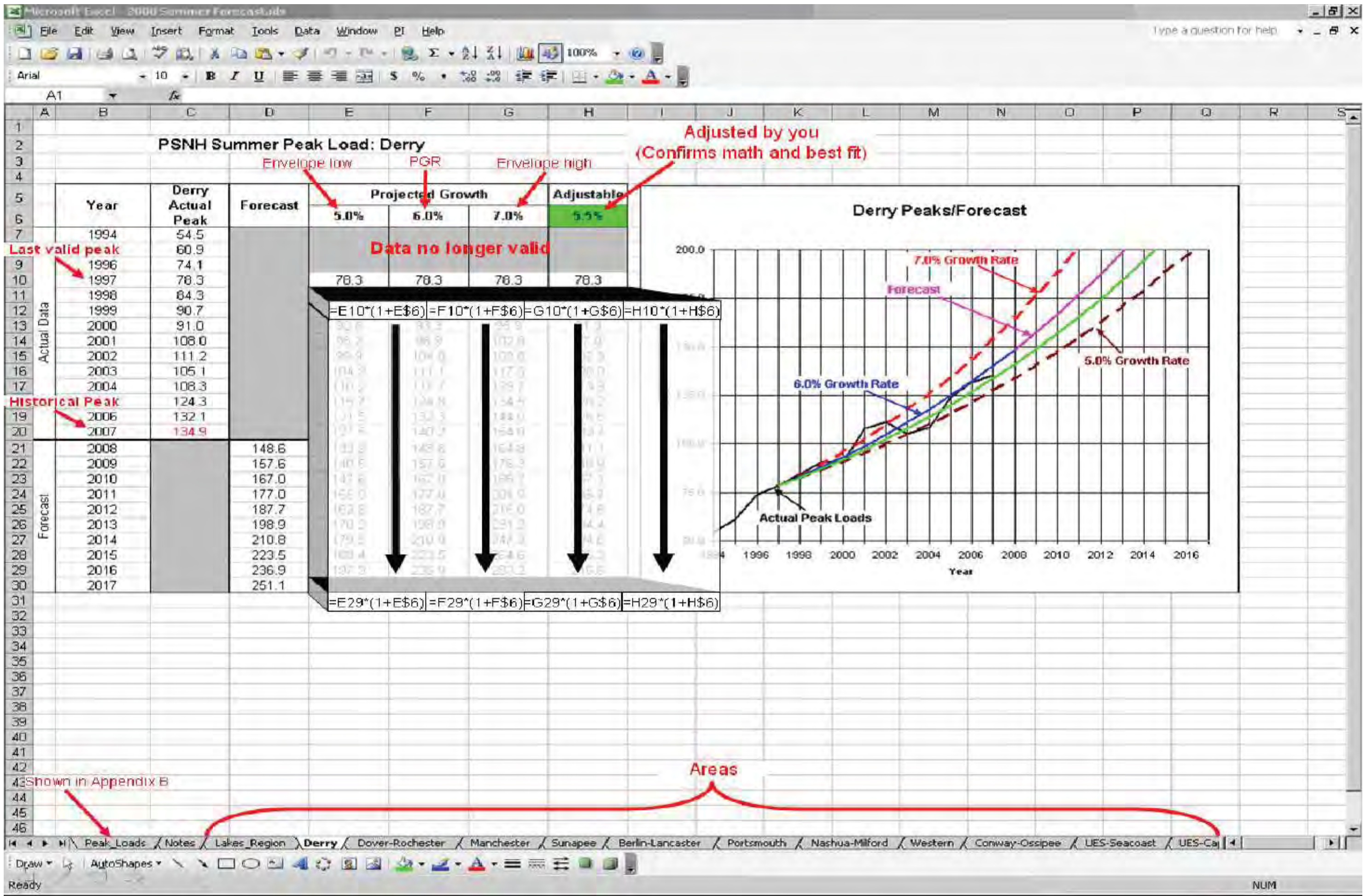
2014 - SUMMER PEAK LOAD FORECAST

YEAR	Lakes Region (MW)	%Difference	<== Adjustment for Webster Valve	<== New Area Forecast	Derry (MW)	%Difference	Dover/Rochester (MW)	%Difference	<== Adjustment for Safran & TurboCar	<== New Area Forecast	Manchester (MW)	%Difference	<== Adjustment for Velcro	<== New Area Forecast	Sunapee (MW)	%Difference	Berlin/Lancaster (MW)	%Difference
2002	162.6	-0.2%			111.2	3.0%	145.4	3.1%			316.4	2.1%			36.9	8.5%	58.3	-26.5%
2003	159.0	-2.2%			105.1	-5.5%	143.1	-1.6%			313	-1.1%			32.9	-10.8%	75.6	29.7%
2004	155.0	-2.5%			108.3	3.0%	136.2	-4.8%			314.5	0.5%			32.6	-0.9%	61.5	-18.7%
2005	180.0	16.1%			124.3	14.8%	162.3	19.2%			360.4	14.6%			36.5	12.0%	70.5	14.6%
2006	190.6	5.9%			132.1	6.3%	169.1	4.2%			357.5	-0.8%			37.3	2.2%	68.7	-2.5%
2007	170.9	-10.3%			134.9	2.1%	161.5	-4.5%			355.2	-0.6%			39.6	6.2%	63.8	-7.2%
2008	174.8	2.3%			132.6	-1.7%	156.1	-3.3%			366.5	3.2%			35.0	-11.6%	51.8	-18.9%
2009	165.6	-5.2%			122.0	-8.0%	156.8	0.5%			335.5	-8.5%			35.6	1.7%	47.0	-9.2%
2010	178.7	7.9%			133.5	9.5%	167.5	6.8%			363.7	8.4%			38.4	7.9%	55.3	17.6%
2011	187.3	4.8%			136.0	1.8%	175.2	4.6%			367.3	1.0%			39.5	2.9%	56.4	2.1%
2012	169.5	-9.5%			130.5	-4.1%	160.9	-8.2%			353.0	-3.9%			37.1	-6.1%	52.8	-6.4%
2013	182.6	7.7%			135.0	3.5%	172.4	7.2%			365.1	3.4%			41.5	11.9%	54.1	2.5%
Compounded Growth Rate		1.16%				1.85%		1.71%				1.37%				1.31%		-2.89%
Adjusted Growth Rate (Years 1-5)		1.50%				2.50%		2.10%				2.00%				1.80%		0.50%
Projected Growth Rate (Years 6-10)		1.25%				2.00%		1.75%				1.50%				1.50%		0.50%
2014	195.9		3.5	199.4	146.5		186.5		7.2	193.7	389.8		4	393.8	42.2		57.3	
2015	198.8		3.5	202.3	150.1		190.4		11	201.4	397.6		4	401.6	43.0		57.5	
2016	201.8		3.5	205.3	153.9		194.4		11	205.4	405.5		4	409.5	43.8		57.8	
2017	204.8		3.5	208.3	157.7		198.5		11	209.5	413.6		4	417.6	44.6		58.1	
2018	207.9		3.5	211.4	161.7		202.6		11	213.6	421.9		4	425.9	45.4		58.4	
2019	210.5		3.5	214.0	164.9		206.2		11	217.2	428.2		4	432.2	46.1		58.7	
2020	213.1		3.5	216.6	168.2		209.8		11	220.8	434.7		4	438.7	46.7		59.0	
2021	215.8		3.5	219.3	171.6		213.5		11	224.5	441.2		4	445.2	47.4		59.3	
2022	218.5		3.5	222.0	175.0		217.2		11	228.2	447.8		4	451.8	48.2		59.6	
2023	221.2		3.5	224.7	178.5		221.0		11	232.0	454.5		4	458.5	48.9		59.9	

YEAR	Portsmouth (MW)	%Difference	Nashua/Milford (MW)	%Difference	CVEC (MW)	%Difference	PSNH (MW)	%Difference
2002	211.1	1.5%	391.7	4.7%	-		1689	4.0%
2003	213.3	1.0%	381.1	-2.7%	-		1677	-0.7%
2004	213.7	0.2%	368.5	-3.3%	29.1		1625	-3.1%
2005	250.1	17.0%	411.8	11.8%	32.3	11.1%	1847.1	13.7%
2006	267.5	7.0%	408.1	-0.9%	33.9	5.0%	1918.3	3.9%
2007	254.2	-5.0%	411.4	0.8%	29.5	-12.9%	1812.9	-5.5%
2008	255.1	0.4%	409.2	-0.5%	30.5	3.3%	1811.8	-0.1%
2009	236.6	-7.3%	374.8	-8.4%	28.9	-5.3%	1734.8	-4.3%
2010	256.1	8.2%	394.0	5.1%	31.3	8.4%	1857.5	7.1%
2011	260.8	1.8%	397.5	0.9%	32.1	2.6%	1888.5	1.7%
2012	260.4	-0.2%	385.3	-3.1%	27.1	-15.5%	1793.3	-5.0%
2013	262.2	0.7%	397.9	3.3%	30.7	13.2%	1889.2	5.3%
Compounded Growth Rate		2.09%		0.14%		1.10%		1.02%
Adjusted Growth Rate (Years 1-5)		3.30%		1.00%		1.40%		1.50%
Projected Growth Rate (Years 6-10)		2.25%		0.50%		1.25%		1.25%
2014	287.5		409.5				1974.8	
2015	297.0		413.6				2004.4	
2016	306.8		417.8					
2017	316.9		422.0					
2018	327.3		426.2					
2019	334.7		428.3				2122.2	
2020	342.2		430.4				2148.7	
2021	349.9		432.6				2175.5	
2022	357.8		434.8				2202.7	
2023	365.9		436.9				2230.3	



APPENDIX H - UPDATE AREA CHARTS AND GRAPHS



ED-3002 Distribution System Planning and Design Criteria Guidelines

I. PURPOSE

To establish guidelines to assist in planning and designing a distribution system that meets customer needs and regulatory requirements.

II. AREAS/PERSONS AFFECTED

This procedure applies to:

- Energy Delivery - system planning and design personnel

III. POLICY

It is the policy of PSNH:

A. To provide a reliable, cost effective, and efficient distribution system to meet customer needs while meeting regulatory requirements.

B. To insure adequate power distribution capacity during all times including normal summer and winter **peak load conditions**.

C. To examine **contingent** outages of substation equipment and circuits to identify areas subject to risk.

D. To insure a consistent approach to the planning for expansion and enhancement of the local area system.

E. To use sound engineering judgment when recommending construction for long term solutions when the design guidelines are exceeded.

F. To design the 34.5 kV distribution system to maximize performance and minimize cost by adhering to design criteria as outlined in this procedure.

IV. DEFINITIONS

Throughout the guideline, defined terms appear in bold and have a specific definition, which can be found in Appendix A.

V. OVERVIEW

This Operating Procedure provides distribution system design and planning guidelines for the 34.5kV and below systems. The 115kV and 345kV transformation to 34.5kV is included.

It is the intent of this guideline to promote the development of long term system solutions based on sound engineering and financial judgment. Short-term solutions **shall** be utilized only when prudent in the long-term planning of the system.

VI. PERIODIC REVIEW OF GUIDELINE

The Procedure Owner is responsible for maintaining this guideline and keeping current with good engineering design practices. The Procedure Owner for this Energy Delivery Procedure is the Manager of System Planning and Strategy or designee.

Annually, the Procedure Owner **shall** review design guideline for conformance to standard engineering practices and industry criteria to determine if the guideline **shall** be revised, rewritten, or cancelled.

As required, the Procedure Owner **shall** recommend changes to the Director of Energy Delivery. If approved by the Director, the Procedure Owner **shall** change the Procedure in accordance with AP-2001 Writing and Publishing Procedures.

VII. GUIDELINES

A. Normal Operation

Normal Operation is how the system is designed to operate during **peak load conditions**. The system **shall** be designed such that during normal operation no switching is required to maintain equipment within its normal thermal ratings.

For design purposes, the system **shall** be capable of serving native PSNH load during **peak load conditions** without relying on the facilities of customers or neighboring utilities unless in accordance with a specific contract.

Areas that may require system enhancements for Normal Operation are identified when **distribution power transformers** are loaded to within 85% of their **TFRAT** (transformer rating). Those areas will be specifically evaluated in order to determine proper budget and construction schedule such that system enhancements are in place the year prior to distribution power transformers exceeding their TFRAT. Refer to ED-3023, Appendix B, for guidance.

No load loss **shall** be permitted under normal Summer or Winter **peak load conditions**.

Each **system generator** will be modeled on and off during **peak load conditions** to assure adequate supply to the area. One generating unit at a time or the largest unit at a facility will be removed from the system model to examine the effect.

Distribution circuits to which **Independent Power Producers (IPP)** are connected will be designed to carry load in accordance with IPP contractual guidelines. IPP will be modeled on, off, and at varying power factors in accordance with the generator capabilities.

The use of **dispatchable peak shaving generation** as defined in Appendix A is acceptable for managing peak load issues in specific locations to manage capital investments on the system.

Known common supply conditions for generation facilities will be considered for impact on the system. This includes the effect of drought on all hydro-electric generation in an area, common fuel/gas supplies for multiple generation units, air emission standard constraints, etc.

B. Contingent Operation

Contingent Operation is the result of the failure of equipment during **peak load conditions**. The following **contingencies shall** be examined for system impact during **peak load conditions**.

1. Loss of 34.5 kV line breaker.
2. Loss of a **distribution power transformer**.
3. Loss of radial transmission lines.
4. Loss of non-radial transmission lines.
5. Loss of **dispatchable peak shaving generation**.

Each **system generator** will be modeled on and off during Contingent Operations. The reliability and ability to utilize the generation during **peak load conditions** will be examined in the event that a specific generating facility supports the system during Contingent Operation.

During Contingent Operation some loss of power to customers (load isolation) will be accepted at the time of **peak load conditions**. The following guidelines **shall** be used to determine the level of severity and need for construction:

1. The load isolation does not exceed 30 MVA and the duration of the outage does not exceed 24 hours.
2. **Load block transfers** on the 34.5kV system are an acceptable means for reducing exposure and typically **shall** not exceed three.

This design criteria recognizes that most PSNH transformers can be backed up by a mobile transformer or faulted circuits can usually be repaired in less than twenty-four hours unless under very adverse conditions.

Appendix A – Design Guideline Summary

Design Condition	Load Level	Generation	Allowable Element Loading Limit[1]	Allowable Element Loading Duration	Allowable Loss of Load Limit	Allowable Loss of Load Duration
Normal Configuration – all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ up to half of internal, non-utility generating units out of service	≤ Normal	Continuous	none	---
outage of generating plant			≤ Normal	Continuous	none	---
Contingency Configuration – loss of non-radial line			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
loss of a Unitil system supply transformer			≤ LTE	Per transformer rating summary	none	---
loss of radial line (no backup tie)			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
*loss of an external system supply transformer			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Extreme Peak – all elements in service	≤ Extreme Peak Load		≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

(S) = Summer load cycle
(W) = Winter load cycle

* Loss of load up to these limits is allowed in cases where Unitil distribution service is supplied by another utility from a site without an on-site back-up transformer. This criteria is intended to facilitate the installation of a mobile transformer in order to restore load.

[1] STE loading is acceptable following a loss-of-element contingency, provided actions are available to relieve the loading within 15 minutes.

nationalgrid

Distribution Planning Guide

Rev. 1

Approved by: ____________ **Date:** 2/15/11

Patrick Hogan, Sr. VP
Distribution Asset Management
National Grid USA Service Company

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document		

Distribution Planning Criteria Strategy
Table of Contents

Strategy Statement

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

For normal loading conditions, all types of facilities are to remain within their normal ratings at all times. For N-1 contingency situations it is expected that load shall be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair of a failed device. Where practical, switching flexibility should be integrated into the system design to minimize the duration of customer outages following an N-1 contingency to meet reliability objectives. The following shall guide contingency planning on the distribution system:

1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.) For the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

3.) For the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

Application of these criteria will result in somewhat less load at risk than previous criteria in either New York or New England which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 1:

Table 1 - Comparison of Capital Costs between Existing and New Criteria

Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in an increase in capital requirements up to $50M/year over the existing criteria for the 15-year period studied.

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities may be required over the next 15years.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long-term strategy and it is expected to take the full 15 year horizon to achieve compliance with existing facilities system-wide.

Performance targets for the adoption of the new planning criteria are:

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.

- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0 1	10/14/2009 2/15/2011	Initial draft Final approved document	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management

Strategy Justification

1.0 Purpose and Scope

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

A map showing National Grid electric service territory within New England and upstate New York is attached in Appendix A.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of National Grid is comprised of all lines and equipment operated at a voltage below 69kV in New England and below 115kV in New York. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within National Grid are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level. In Upstate New York approximately 70% of the substations have either a single source or a single transformer. In New England 40% of the substations have a single source and/or transformer.

A typical substation involves a 115/13 kV, 25-40 MVA rated transformer with either a load tap changer built into the transformer or individual voltage regulators applied to the feeders. In many locations, two or three transformers are within one substation and will interconnect via bus tie breakers. Many of the distribution substations supplied by the 115kV circuits also include one or more capacitor banks for reactive support.

National Grid maintains approximately 680 distribution substations containing approximately 1,530 power transformers. The total number of distribution substations, transformers, circuit miles of overhead and underground within NE and UPNY is listed in Distribution Line Overarching Strategy paper dated July 2008.

2.1.2 Sub-Transmission systems

The sub-transmission system within National Grid is designed to provide adequate capacity between transmission sources and load centers at reasonable cost and with minimal impact on the environment. The National Grid sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are neither bulk transmission nor distribution. The typical voltages for the sub-transmission system include 46, 34, and 23 kilovolts. In New York, the sub-transmission also includes the 69 kV.

Sub-transmission systems may be designed in a closed or open loop system originating from transmission substations, and generally providing a redundant supply for distribution substations. In other cases, a single radial sub-transmission supply line may serve load. The substations served from a sub-transmission line will serve approximately 10-40 MW of load depending on the voltage.

Generally, the sub-transmission system is presently designed with conductors ranging from 336.4 ACSR (UPNY) to 795 kcmil AAC (NE) overhead conductor and from 500 to 2000 kcmil copper underground conductor. However, most of the sub-transmission lines are older designs and built with smaller wire such as 2/0 AWG copper installed along right-of-ways or on public streets.

There are approximately 930 sub-transmission lines in New England and upstate New York within National Grid.

2.1.3 Distribution Feeders

Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductor. Feeders are designed in a radial configuration. The feeder mainline will typically have several normal open tie points to one or more adjacent feeders for backup. Protection for faults on the feeders consists of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits.

The National Grid Primary distribution system in New England and upstate New York is comprised of approximately 3,770 feeders.

2.1.4 Secondary Networks

Low voltage secondary networks have historically been employed in several urban areas to maximize the reliability for the customers in these areas. They typically have a 120/208V class secondary system that is connected as a grid with many downtown customers connected. Most of the secondary networks have from 4-10 supply feeders. The low voltage secondary network supply feeders will typically have 10-30 network transformers connecting into the secondary grid.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, 2-3 supply feeders are used to serve the spot networks.

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for New England and New York will be based on a regional econometric regression model that considers historic loading, weather conditions, various economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years. Separate models are used for NE and UPNY.

2.2.1.2 Equipment Ratings

Distribution Planning maintains equipment ratings for New England and New York. The summer and winter normal and summer and winter long time emergency (LTE) ratings will be used. The major equipment ratings to be used by Distribution Planning relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for these items may be applied for the time associated with each rating. Generally, the durations for emergency loading are as listed below in Table 2. System operators must be aware of the limiting factor involved in any contingency:

Table 2 - Equipment Rating Durations

Equipment		Normal	LTE	STE
Transformer		Continuous	24 hour	15 Min
Overhead Line		Continuous	24 hour	N/A
Underground Cable		Continuous	24 hour	N/A

There is also a short time emergency rating which may be determined for substation transformers, in no instance should this rating exceed 200% of nameplate rating. In addition to the items in the above table, ratings are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers.

2.2.1.3 Planning Study Areas

A planning study area within National Grid is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in NE and UPNY to be used by Distribution Planning are presented in Appendix B.

2.2.1.4 Load Flows

Distribution planning studies will utilize the PSS/e load flow program for the study of the sub-transmission lines and networks. The distribution feeder load flow analyses will be done using the Cymedist feeder analysis software program.

2.2.1.5 Distribution Analysis Alternatives

When performing distribution system analyses, Distribution Planning shall consider both traditional capacity enhancements as well as alternatives for "Non-Wires" customer load management alternatives where appropriate. The factors below could impact capacity planning analysis

a. Distributed Generation
b. Controllable Load Curtailment
c. Energy Storage devices
d. Demand Side Management

e. Distribution Automation
f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods.

2.2.2.2 Contingency N-1 substation transformer planning criteria

For an N-1 contingency condition that would involve the loss of a power transformer or substation bus, the following planning criteria apply:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

Many locations with two or more transformers at a substation utilize automatic bus transfers. In some stations, one bus tie breaker is used, while in other substations a breaker and half design is utilized and there may be several feeder bus tie breakers. Based on the loading limitations in Section 2.2.2.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during an N-1 contingency. Cases where automatic restoration are disabled will be documented and communicated with Regional Control Centers as part of an annual summer preparedness review. Recommendations to add capacity to the area will be evaluated and prioritized based load at risk, reliability and cost with other Load Relief alternatives.

When available, the use of the Energy Management System (EMS) control shall be implemented as needed to block automatic transfer. During an N-1 contingency, the System Operator will be required to maintain the loading on transformers as specified in Section 2.2.2.2.

2.2.2.4 Substation reactive support criteria

Reactive compensation shall be required for substations in the form of station capacitor banks or static VAR compensators. These should be sized to offset the reactive losses of the transformers at full load. Two or three stage capacitor banks may be needed for larger transformers to manage power factor and to limit voltage fluctuations.

2.2.2.5 Impact of planned maintenance

Capacity in all areas should allow the off loading of any distribution substation transformer for planned maintenance during the off peak months without exceeding the normal ratings of the other area equipment. However, in areas of the system with limited feeder ties, it may be more economical to allow the installation of a mobile transformer for maintenance.

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

A sub-transmission supply line will not be loaded above its normal rating during non-contingency operating periods.

2.2.3.2 Contingency N-1 sub-transmission planning criteria

For an N-1 contingency condition that would involve the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Load on the remaining sub-transmission line will need to be reduced to normal levels within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The limit of load at risk for the loss of any sub-transmission line will be 20MW.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.3.3 Automatic line transfer systems

Auto transfer of load on the sub-transmission may be employed, but may not exceed the emergency (LTE) ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

2.2.3.4 Sub-transmission reactive support criteria

Reactive compensation for sub-transmission lines shall be required in the form of station and distribution capacitor banks.

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

A distribution feeder circuit will not be loaded above its normal rating during non-contingency operating periods.

2.2.4.2 Contingency N-1 feeder planning criteria

For an N-1 contingency condition that would involve the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.4.3 Automatic transfers on feeders

In some cases, it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers.

2.2.4.4 Feeder reactive support criteria

Reactive compensation for feeders should be installed to provide additional capacity, improve voltage regulation and meet external power factor standards where applicable. A mixture of fixed and switched capacitor banks may be used as needed. All feeders in a planning area shall have proper reactive compensation prior to any requests for other load relief infrastructure improvements.

2.2.4.5 Feeder load balance criteria

Distribution Planning studies are based on three phase average loading. Load balance between the three phases on any feeder is assumed to be within a reasonable level.

Distribution feeder load balance shall require correction of the load imbalance for either of the following cases:

- Any feeder with the calculated neutral current exceeding 30% of the feeder ground relay pickup setting.

- Any feeder exceeding 100A between the high and low phase amps.

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution standards. The criteria are different for NE and UPNY based on the history of how various networks evolved.

2.2.6 Voltage criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

The normal and emergency voltage to all customers shall be in line with limits specified by state regulators and within the limits of ANSI C84.1

These upper and lower voltage limits for each state in the service territory are listed in Table 3 below:

Table 3 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New Hampshire	126	120	114
New York	123	120	114
Rhode Island	123	120	113

The values in Table 3 are in line with the National Grid Overhead Construction Standards.

Voltage on the sub-transmission and primary feeders is determined by many factors including:

- Primary mainline conductor sizes
- Distance of lines
- Reactive compensation

Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or padmounted line regulators. Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 3 above are maintained.

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

The goal of the new planning criteria is to maintain the performance of the electric distribution system. Generally, after compliance with the new criteria, the residual risk for the worst case will be 10 MW of load out for 24 hours for a substation transformer failure or 20 MW out for 12 hours for an overhead supply line failure.

2.3.2 Methodology to prioritize capital projects

Prioritization of capital projects utilizes scoring system that considers the consequence of not completing the project and the probability that the consequences will be realized. A risk score between 1 and 49 is developed utilizing a 7x7 scoring matrix.

3.0 Risks/Benefits

The principal impacts of the planning criteria are reliability performance, customer service and efficiency. Due to the extended time frame for strategy compliance, the impact of the strategy will not be initially visible at the system level. These benefits will be most apparent in those areas where it has been implemented.

3.1 Safety & Environmental

Safety and environmental factors are not principal drivers of the planning strategy. However, the planning criteria will ensure equipment loading is maintained within accepted ratings reducing the risk of premature equipment failure that could result in environmental and public safety concerns.

3.2 Reliability

The planning criteria will provide operating flexibility to facilitate the restoration of customer outages following an N-1 contingency event. With an expected long implementation schedule, the impact will not be initially visible at the system level but will be significant in the areas where the criteria have been implemented. A long range reliability improvement of 11.4 minutes in SAIDI and 0.073 in SAIFI on a system basis is forecasted if the strategy is implemented over a 15 year planning horizon. Additionally, lower feeder loading will support future distribution automation to further improve reliability.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers.

3.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation and study area loading analysis across NE and UPNY. All studies being conducted under one criterion will create a consistent reference for ranking projects as part of the business planning process.

4.0 Estimated Costs

The estimated costs to adopt the new planning criteria are summarized as follows:

The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 4:

Table 4 - Comparison of Capital Costs between Existing and New Criteria

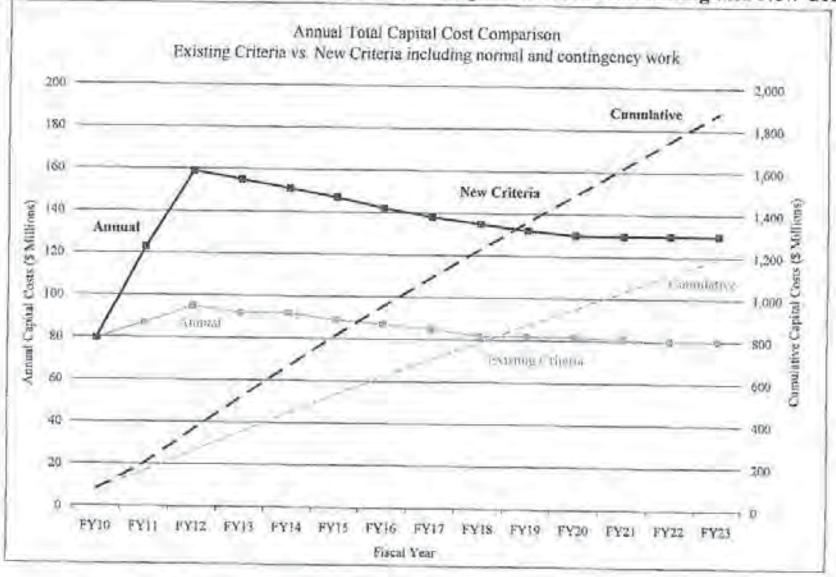
Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in increased in capital costs of $50M/year in the Load Relief budget category compared to previous criteria for the 15-year period studied.

Based on an analysis of normal loading issues, it is projected that capital work associated with normal loading will remain at present levels or slightly higher for several years and then ramp down as contingency projects will tend to drive the load relief spending.

These combined normal and contingency capital costs are shown in Figure 1 below:

Figure 1 - Annual and Cumulative Capital Cost Comparison between Existing and New Criteria



5.0 Implementation

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities are forecasted to be required over the next 15 years in NE and UPNY.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long term strategy and it is expected to take many years to implement system-wide.

6.0 Data Requirements

The data sources required for the proper execution of the planning strategy include:

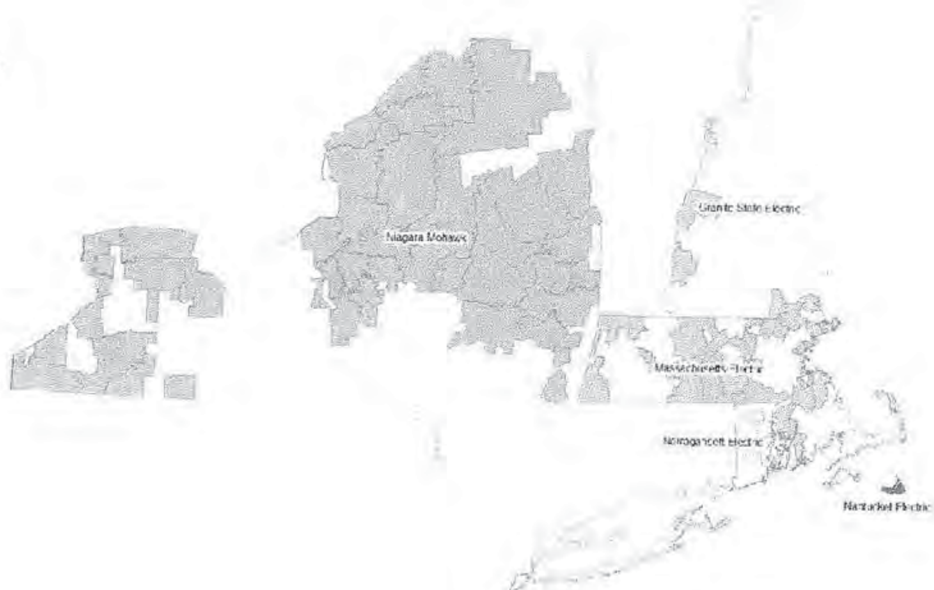
6.1 Planning Tools:

Cymedist (Cyme) – for radial feeder load flow and voltage analysis
Smallworld GIS – to support Cyme analysis
PSS/e – for network load flow analysis
FeedPro - for equipment loading and ratings
EMS and PI or ERS access in NE and UPNY

Appendix A – Service Territory Maps

Maps of Electric Distribution Service Territories for five companies and five divisions:

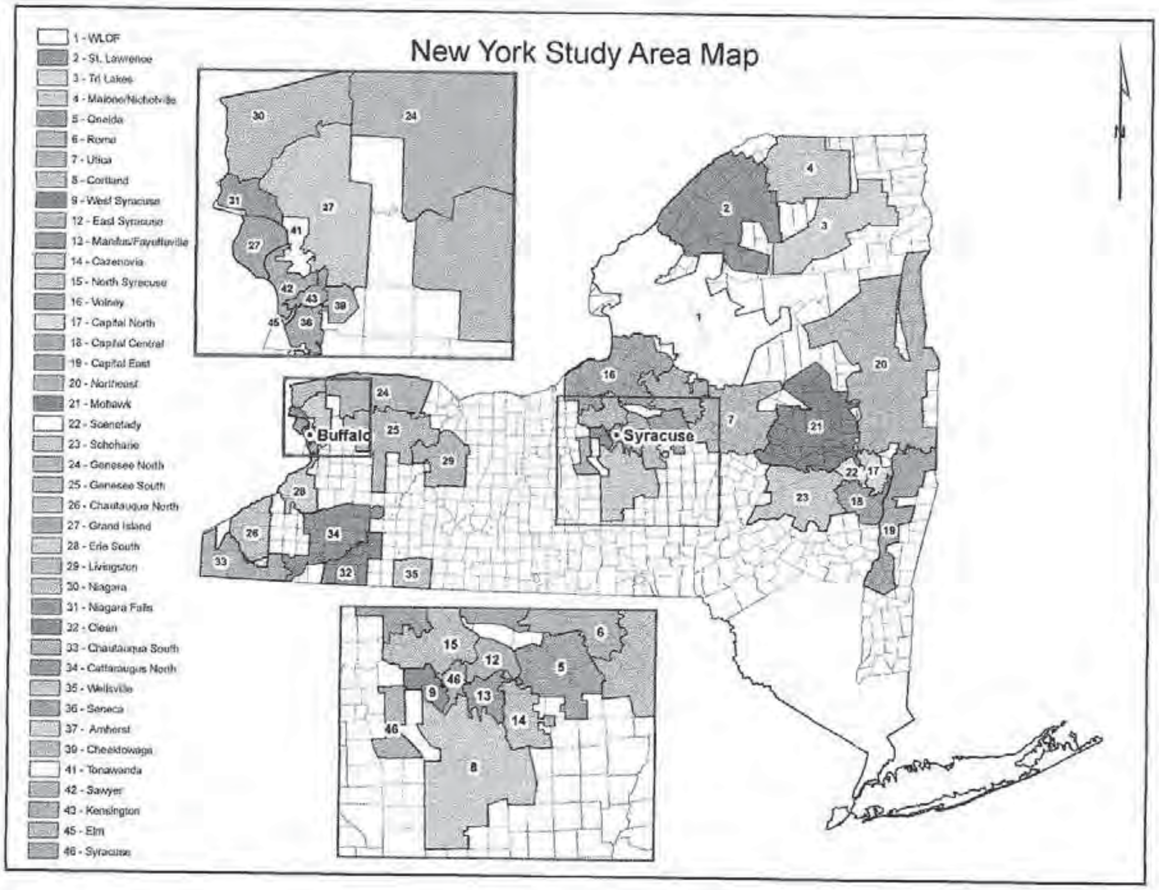
Companies

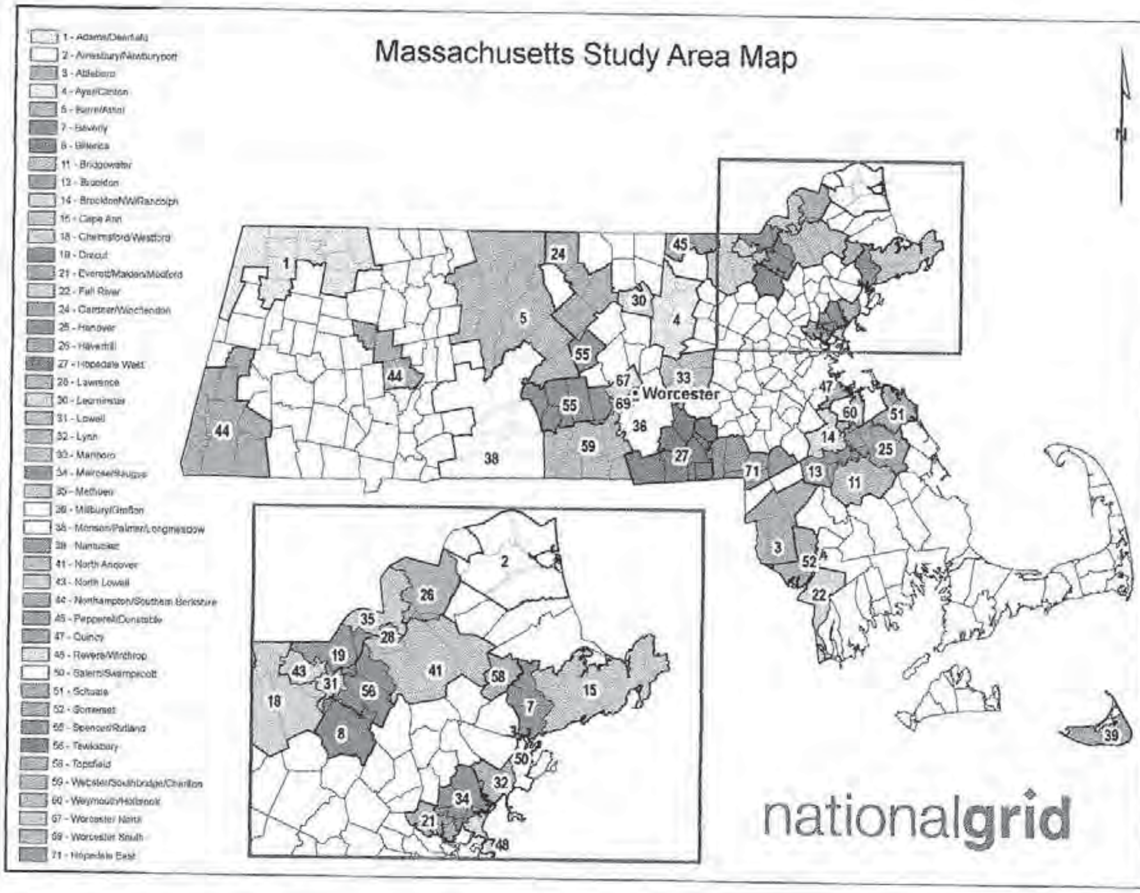


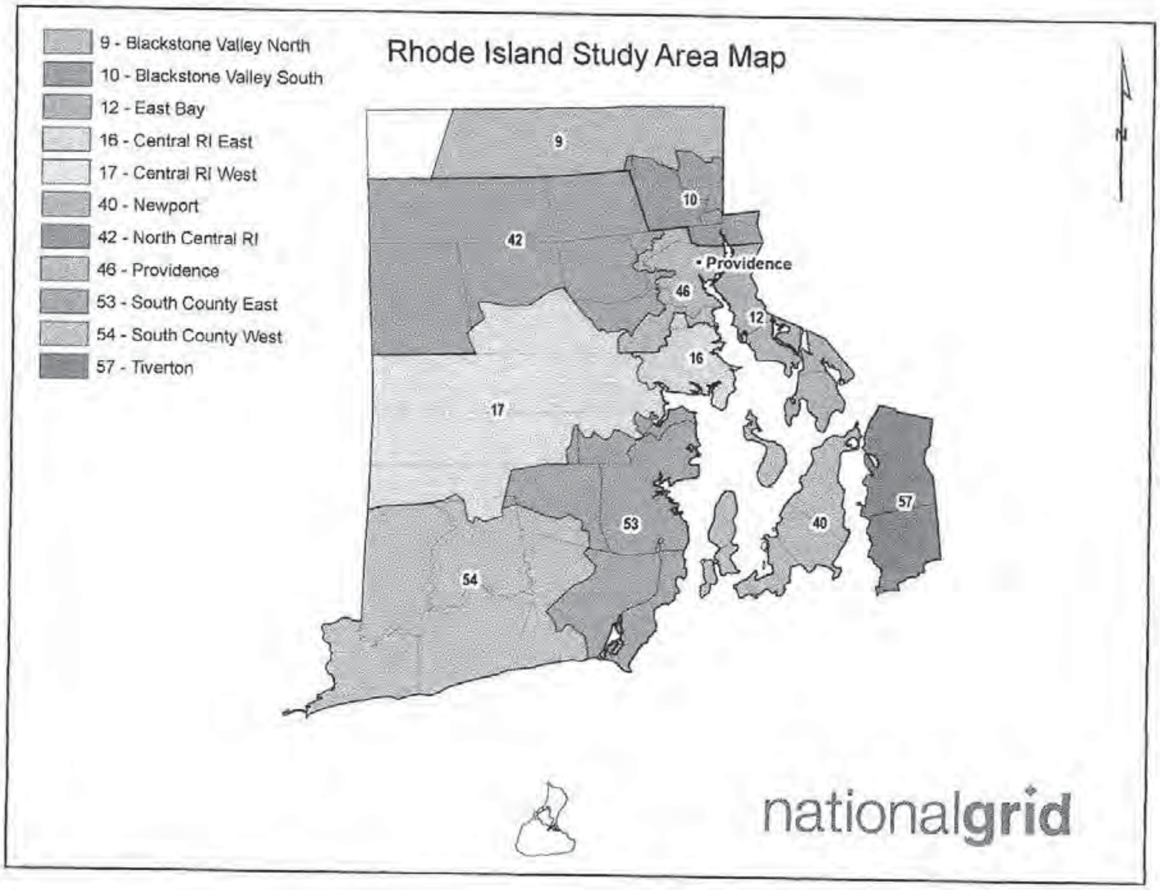
Divisions

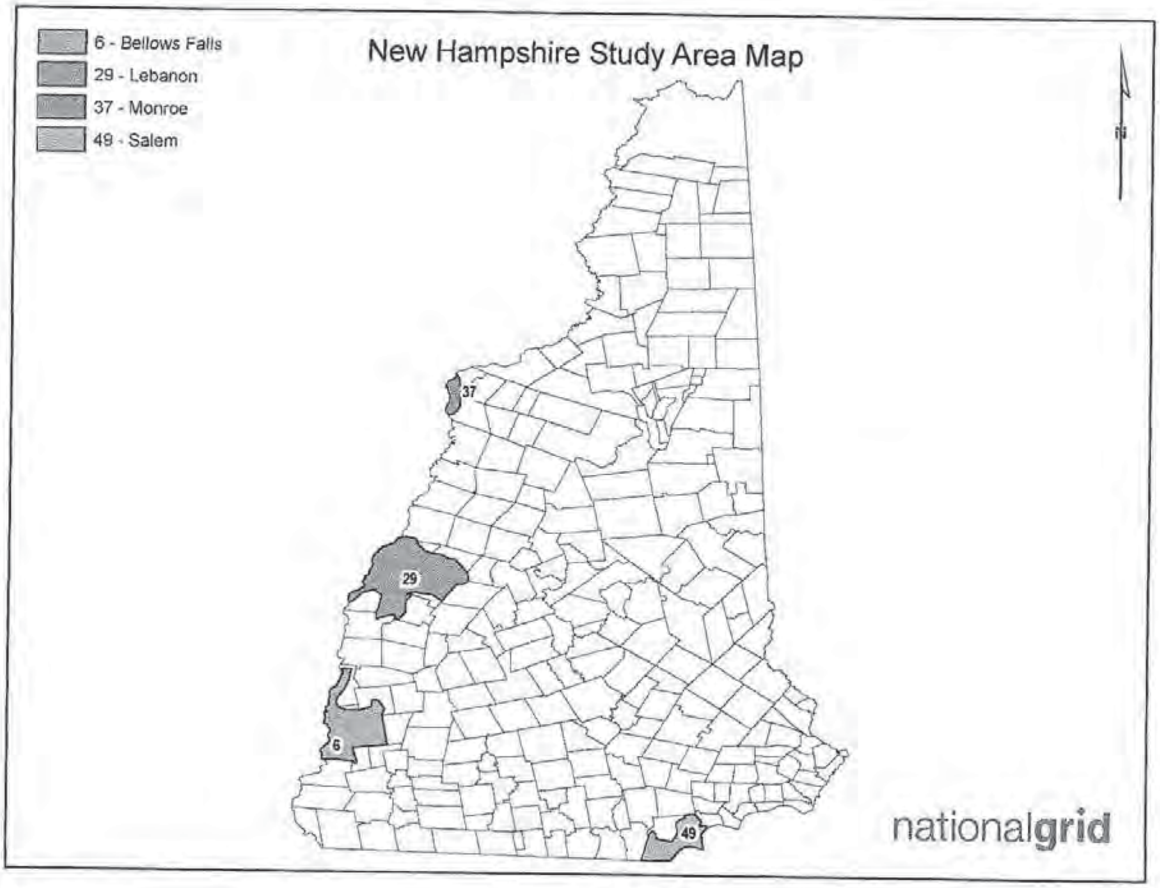
Appendix B - Distribution Planning Study Areas

To foster the annual capacity planning assessment, the distribution system across UNY and NE has been segmented into Planning Study Areas as shown in the following figures.




Massachusetts Study Area Map
2 - Amesbury/Newburyport
3 - Attleboro
11 - Bridgewater
14 - Brockton NW/Randolph
15 - Cape Ann
18 - Chelmsford/Westford
19 - Dracut
21 - Everett/Malden/Medford
22 - Fall River
24 - Gardner/Winchendon
25 - Hanover
26 - Haverhill
27 - Hopedale West
28 - Lawrence
30 - Leominster
31 - Lowell
32 - Lynn
33 - Marlboro
35 - Methuen
36 - Millbury/Grafton
38 - Monson/Palmer/Longmeadow
39 - Nantucket
41 - North Andover
43 - North Lowell
44 - Northampton/Southern Berkshire
45 - Pepperell/Dunstable
47 - Quincy
48 - Revere/Winthrop
50 - Salem/Swampscott
51 - Scituate
52 - Somerset
55 - Spencer/Rutland
56 - Tewksbury
58 - Topsfield
59 - Webster/Southbridge/Charlton
60 - Weymouth/Holbrook
67 - Worcester North
69 - Worcester South
71 - Hopedale East
Worcester
N
nationalgrid


9 - Blackstone Valley North
10 - Blackstone Valley South
12 - East Bay
16 - Central RI East
17 - Central RI West
40 - Newport
42 - North Central RI
46 - Providence
53 - South County East
54 - South County West
57 - Tiverton
Rhode Island Study Area Map
N
9
10
42
Providence
46
12
16
17
53
40
57
54
nationalgrid


6 - Bellows Falls
29 - Lebanon
37 - Monroe
49 - Salem
New Hampshire Study Area Map
N
37
29
6
49
nationalgrid

1 Abstract

Adequate distribution capacity is key to overall system reliability and proper functioning of system facilities. The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The loading of the system has changed over the years to where various components are at or have exceeded certain planning and operating criteria. In addition, sub-transmission facilities in the area are approaching its design limits. The upcoming developments in the area result in an increase of components exceeding planning and operating criteria.

This Area Study is being carried out to study five (5) possible options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. The recommended plan accomplishes all system capacity and asset replacement requirements. The plan will be achieved in three (3) phases. The first phase recommends the installation of a 115/13.2 kV - 33/44/55 MVA transformer and four 13.2kV feeders at the Golden Rock Substation and the retirement of Baron Avenue Substation. The second phase installs a new double-ended 115/13.2kV substation Rockingham #21 and eight 13.2kV feeders in the Rockingham Park Track and retires the Salem Depot Substation. The third phase replaces the existing 115/23kV transformer at Golden Rock with a 115/13.2kV – 33/44/55 MVA transformer and four 13.2kV feeders and converts the Olde Trolley Substation to a switching/regulator station, and retires the 23kV sub-transmission system in the area. This recommendation is based on the engineering analysis to find the most economical alternative to provide for projected load growth, contingency mitigation, and to asses condition issues of the existing equipment.

2 Executive Summary

Control Point Technologies with the assistance of Liberty Utilities has completed the Salem, NH distribution planning study. The Liberty Utilities Distribution Planning Criteria was used to determine any Electric Supply System upgrades required to meet existing and future capacity requirements. The study focused on the distribution requirements needed to supply the proposed business park development in the range of 14MW – 17MW located at the former Rockingham Park Track. The study also focused on the retirement of Baron Ave Substation, Salem Depot Substation and Olde Trolley substation due to issues with asset condition. The retirement of these substations will set the stage for the retirement of the Salem Area 23kV sub-transmission system.

The Distribution System under study included:

- One (1) 115kV/23kV substation Golden Rock No.19.
- Four (4) 23kV sub-transmission (supply) circuits, 2352, 2393, 2353 and 2376.
- Four (4) 23kV/13.2kV substations, Baron Ave No.10, Olde Trolley No.18, Salem Depot No. 9 and Spicket River No 13.
- Thirteen (13), 13.2kV distribution circuits, 10L1, 10L2, 10L4, 18L1, 18L2, 18L3, 18L4, 9L1, 9L2, 9L3, 13L1, 13L2 and 13L3.

2.1 Explanation

The study, focused on current and future capacity needs of the supply lines, substations and distribution system supplying the area along with the asset conditions of the existing electrical infrastructure. Evaluations identified a number of existing and predicted system Distribution Circuit, Supply Line, and Transformer capacity concerns that did not meet the requirements of the Liberty Distribution Planning Criteria.

Existing Criteria violations, based on 2016 peak loading, were identified for both the Normal Loading and the Contingency Loading cases. These are detailed under Section 3.6 and include the following:

1. Conductor Thermal overloads in excess of 100% Summer Normal ratings on the, 18L4 circuit.

2. During Contingency (N-1) cases, the Salem Depot 9L2 Circuit violates the 16 MWH rule with 3.7 MVA of Load at risk.

3. During Contingency (N-1) cases the Spicket River Loss of 23kV Supply violates the 36 MWH rule with 8.9 MVA load at risk.

4. The 13L2 Circuit, which is limited to 515 Amps by 336 Al OH, exceeds 75% of its Summer Normal rating.

5. The 9L2 Circuit's transformer which is limited to 322 Amps exceeds 75% of its Summer Normal rating.

6. During Contingency (N-1) cases, the loss of supply or transformer at Golden Rock results in 12MW of unserved load, which violates the distribution planning criteria.

In addition to the existing distribution evaluation the study also focused on the distribution requirements needed to supply the proposed business park development in the range of 14 MW - 17 MW located at the former Rockingham Park Track.

Existing loading concerns and planning criteria violations amplify with the addition of the proposed business park and other known spot loads in the area. Existing transformer, distribution circuit and supply line capacity in the Salem area will be exceeded, presenting many challenges to the existing 23kV/13.2kV distribution system. These predicted criteria violations were identified by year for both the Normal Loading and the Contingency Loading cases under Section 3.7.

2.2 Recommended Plan

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4.

The study took into consideration existing distribution asset concerns while determining possible recommendations. These asset concerns are detailed in Section 3.3.

The recommended plan for consideration accomplishes all system capacity and asset replacement requirements. The plan will be achieved in three (3) phases. It addresses the existing concerns and the future concerns in the most complete way while moving the system from the legacy 23 kV supplied system to a more reliable and sustainable 115 kV supplied system. It also provides the capacity needed to supply the proposed business park development in the former Rockingham Park Track.

Phase One (New 115/13.2 kV Transformer at Golden Rock Station with Baron Ave Station Elimination & Spicket River Mitigation)

Phase One of the recommended plan consists of a second 115 kV transmission line into Golden Rock Station supplying a new 115kV/13.2 kV substation transformer with three (3) new 13.2 kV circuit positions. The 13.2 kV circuits would be constructed to provide contingency support to Spicket River Station and to eliminate the Baron Ave Station. It would also be used to mitigate forecasted capacity issues after initial Rockingham expansions in the range of 3MW – 5MW take place. The future circuit #4 will be installed during Phase 2 after the new underground conduit system along the right-of-way (ROW) is installed.

This phase would also include the replacement of existing conductor in excess of 100% of Summer Normal ratings, on the 18L4 circuit. The conductor upgrade would be accomplished using 477 Al spacer cable to the first protective device, then 477 Al open wire or 477 tree wire depending upon field conditions.

Phase One of the Recommended Plan also consists of the removal of the existing 23kV stub bus at the Golden Rock substation to make way for new 13.2kV equipment. The 2352 circuit will also be removed from Golden Rock to Baron Ave.

The total cost of the Phase One project is estimated at $5,584,000.

Phase Two (New 115/13.2 KV Transformers at New Rockingham Station with Salem Depot Station Elimination and Criteria Mitigation)

Phase Two of the recommended plan consists of an extension of the 115 kV transmission system from Golden Rock Station to a proposed new double ended 115kV/13.2kV station in the Rockingham Park Track area. Acquisition of land within the Rockingham Park will be required to install the new substation.

Each new 115 kV/ 13.2 kV supply transformer, T1 and T2, would have four (4) circuits, eight (8) total, with secondary breakers and a bus tie breaker. An automatic bus transfer system would be utilized to improve reliability and simplify maintenance.

Three (3) of the T1 supply transformer circuits would be used to supply a reconfigured 13.2 kV distribution system, which will bring the system into compliance with Liberty's Distribution Planning Criteria. The configuration would be targeted to improve reliability and better balance loading on all circuits.

Three (3) of the T2 supply transformer circuits would be used eliminate the Salem Depot Station and provide backup support to the Olde Trolley substation.

The fourth circuit on both the T1 and T2 supply transformers would serve the proposed business park load.

The two (2) 23kv supply circuits 2352 and 2393 will be relocated from OH to UG along the ROW to make way for the two (2) new 115kV transmission supply lines supplying the new Rockingham Substation. This new underground system along the ROW will also be used for future distribution feeders out of Golden Rock Substation (Phase 3) and for the fourth feeder out of Golden Rock T2.

The total cost of the Phase Two project is estimated at $20,648,000.

Phase Three (Install Second 115/13.2 KV Transformer at Golden Rock Station with Olde Trolley Elimination)

Phase three of the recommended plan consists of a second 115kV/13.2kV substation transformer at Golden Rock with four (4) new 13.2kV feeder positions.

The existing 115kV/23kV Golden Rock transformer is to be removed and the substation is to be converted into a 13.2kV with a breaker and a half scheme. The existing 23kV lines will be converted to 13.2kV distribution circuits. The 13.2 kV circuits would be constructed to provide contingency support to Rockingham Station and Spicket River Station. Phase Three of the Recommended Plan will convert the Olde Trolley Station into a regulating/switching station and will eliminate the 23kV supply system out of Golden Rock.

The total cost of the Phase Three project is estimated at $4,684,000.

2.3 Reasons for Recommendation

The recommended plan addresses existing and predicted normal and contingency operational, capacity, and asset challenges associated with the existing 23kV/13.2kV based distribution system. In addition, the plan addresses, capacity loading concerns developed with the addition of the proposed business park at the former Rockingham Park Track and other known spot loads in the area.

Additionally, Spicket River Station is presently supplied by one 23kV circuit fed from the Transmission Service Provider, National Grid. With the loss of this supply, the existing 13.2 kV circuit ties do not have sufficient capacity to pick up the entire station load on peak. The load at risk resulting from this contingency scenario violates the Liberty Distribution Planning Criteria. The added capacity and 13.2 kV circuits would be constructed from Golden Rock to provide contingency support to Spicket River Station and bring the station into compliance with Liberty's Distribution Planning Criteria.

The opportunity to move the system from a 23kV/13.2kV to a more robust 115kV/13.2kV substation transformer based system is presented. The 115kV/13.2kV transformers will allow larger capacity transformers to be utilized in supplying system demand. By utilizing the additional capacity available from the larger capacity transformers; Liberty Utilities can develop a multi-phased plan to eliminate existing 23 kV facilities, including Baron Ave, Salem Depot station and Olde Trolley, with their legacy maintenance and operational concerns. Also, the recommended plan will decrease the reliance on the 23 kV supply line system and its continued dependence on the Transmission Service Provider to allocate 23 kV capacity for Liberty Utilities.

2.4 Recommended One-lines

Refer to section 5.2 Recommended Plan One-lines, for Station and Distribution Systems.

2.5 Recommendation Estimates

The following tables provide estimated costs, by phase, for the Recommended Plan.

Recommended Plan Phase One Estimate	
Required Construction	**Cost - $k**
Baron Ave Station Elimination & Spicket River Mitigation Distribution Circuit Estimate	**$2,400**
Baron Ave Station Elimination & Spicket River Mitigation Sub-Transmission Circuit Estimate	**$184**
New 115/13.2 kV Transformer at Golden Rock Station Estimate	**$3,000**
Phase One Project Total	**$5,584**

Recommended Plan Phase Two Estimate	
Required Construction	**Cost - $k**
Salem Depot Station Elimination Distribution Circuit Estimate and Design Criteria Compliance	**$6,343**
Salem Depot Station Elimination Sub-transmission Circuit Estimate and 23kV Relocation.	**$8,504**
New 115/13.2 KV Transformer, T1, at New Rockingham Station Estimate	**$2,800**
New 115/13.2 KV Transformer, T2, at New Rockingham Station Estimate	**$3,000**
Phase Two Project Total	**$20,648**

Recommended Plan Phase Three Estimate	
Required Construction	**Cost - $k**
Olde Trolley Elimination Distribution Circuit Estimate	**$150**
Olde Trolley Elimination Sub-transmission Circuit Estimate and 23kV Supply Retirement	**$34**
New 115/13.2 kV Transformer at Golden Rock Station Estimate	**$4,500**
Phase Three Project Total	**$4,684**

If the implementation of a new Rockingham Station is significantly delayed, Salem Depot Station upgrades should be pursued due to issues with asset condition.

In addition, if the implementation of a new Rockingham Station is significantly delayed, the temporary installation of a 23/13.2kV 9.375 MVA transformer within the Rockingham Park should be pursued. One transformer from the retired Baron Avenue substation could be reserved for this application. Although this transformer and sub-transmission supply system would not have the full capacity to supply all of the forecasted expansions in the park, it could buy enough time to supply some new developments in the Park as the new Rockingham Station is being implemented.

Recommended Plan Phase Two Delay Estimate	
Required Construction	**Cost - $k**
Salem Depot Station Upgrades Station Estimate	**$1,550**
Phase Two Project Total (Delay)	**$1,550**

3 Introduction

The Salem, NH area distribution Study was completed to determine any Electric Supply System upgrades required to meet existing and future capacity operational and asset requirements. The study also focused on the distribution requirements needed to supply the proposed business park development in the range of 14MW – 17MW located at the former Rockingham Park Track.

3.1 Geographic Scope

This study was performed on the Liberty Utilities Distribution System supplying Salem, New Hampshire. The system is confined to the City of Salem, NH with small excursions into Windham and Derry, NH and Methuen, MA.

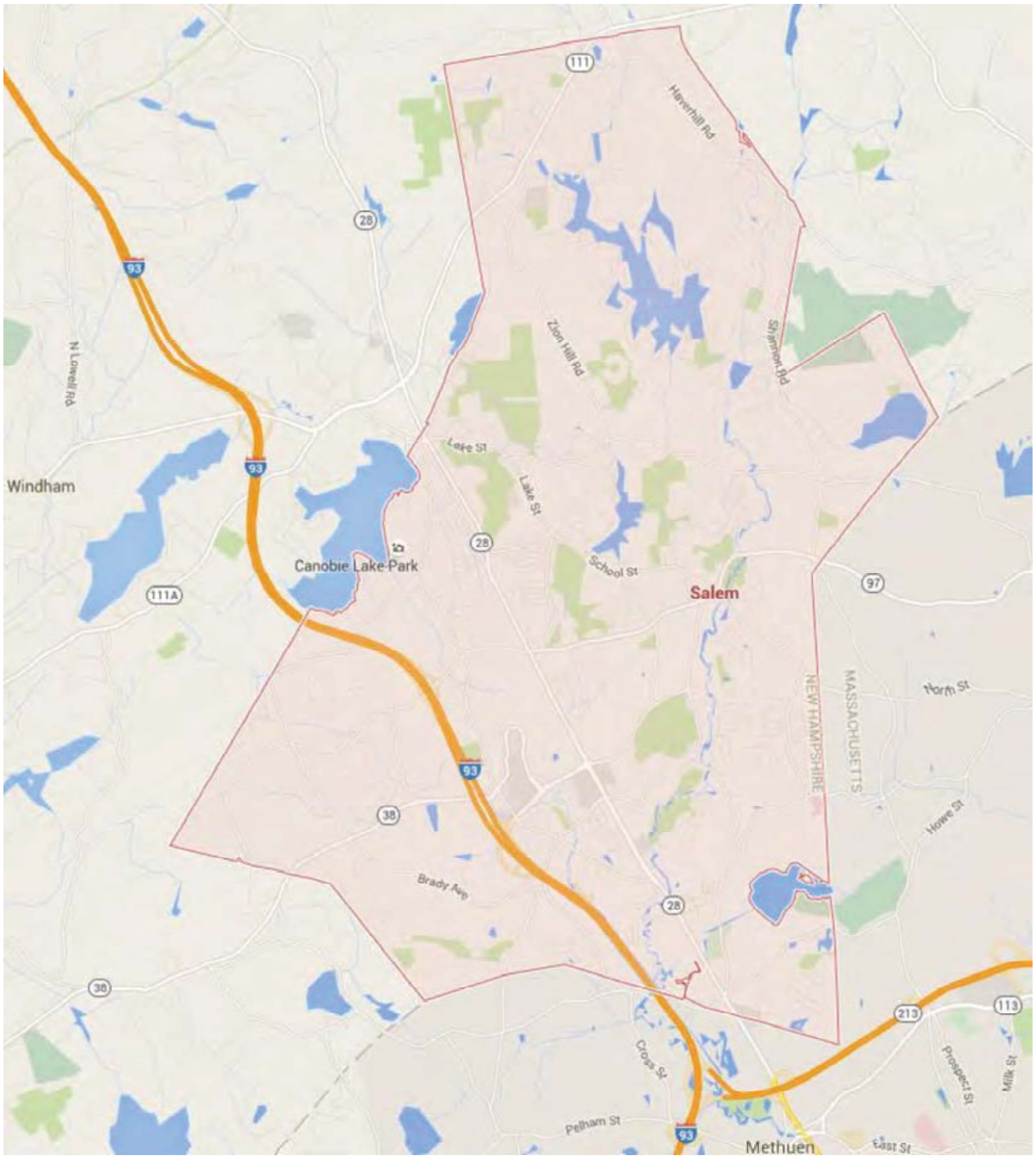


Figure 1 Salem, NH Geographical Map

3.2 Electrical Scope

The Distribution System under study includes the 2352, 2353, 2376, and 2393, 23 kV supply circuits; refer to *Figure 2, Salem Area 23 kV Supply System One-Line*. These circuits supply four (4) 23kV/13.2kV substations: Baron Ave No.10, Olde Trolley No.18, Salem Depot No. 9 and Spicket River No 13 and one 23kV customer station “Jockey Club”.

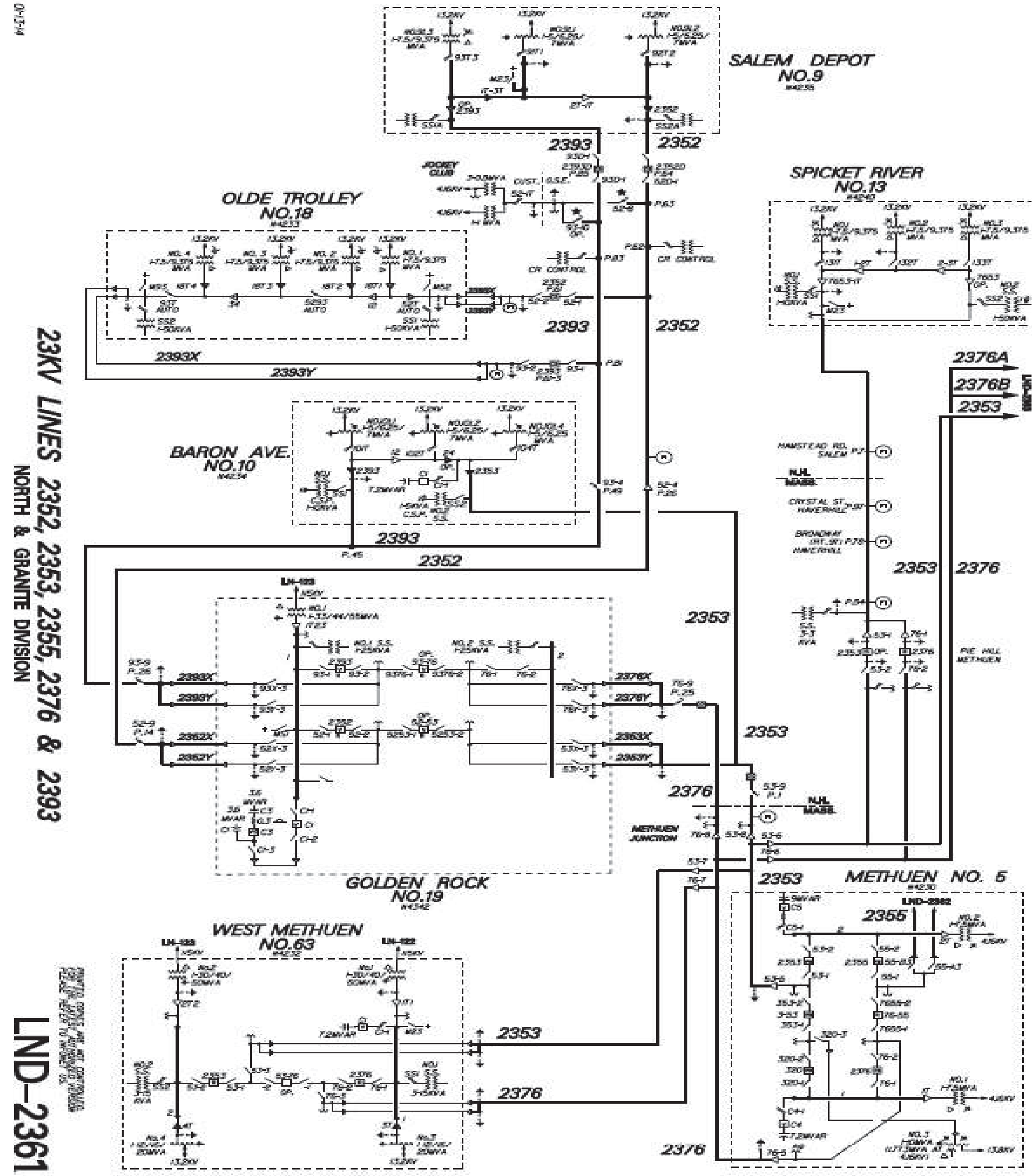


Figure 2 Salem Area 23 kV Supply System One-line

The substations supply thirteen (13) 13.2kV circuits, refer to *Figure 3, Salem Area 13.2kV Supply System One-line*:

1. Baron Ave: 10L1, 10L2, 10L4
2. Olde Trolley: 18L1, 18L2, 18L3, 18L4
3. Salem Depot: 9L1, 9L2, 9L3
4. Spicket River: 13L1, 13L2, 13L3

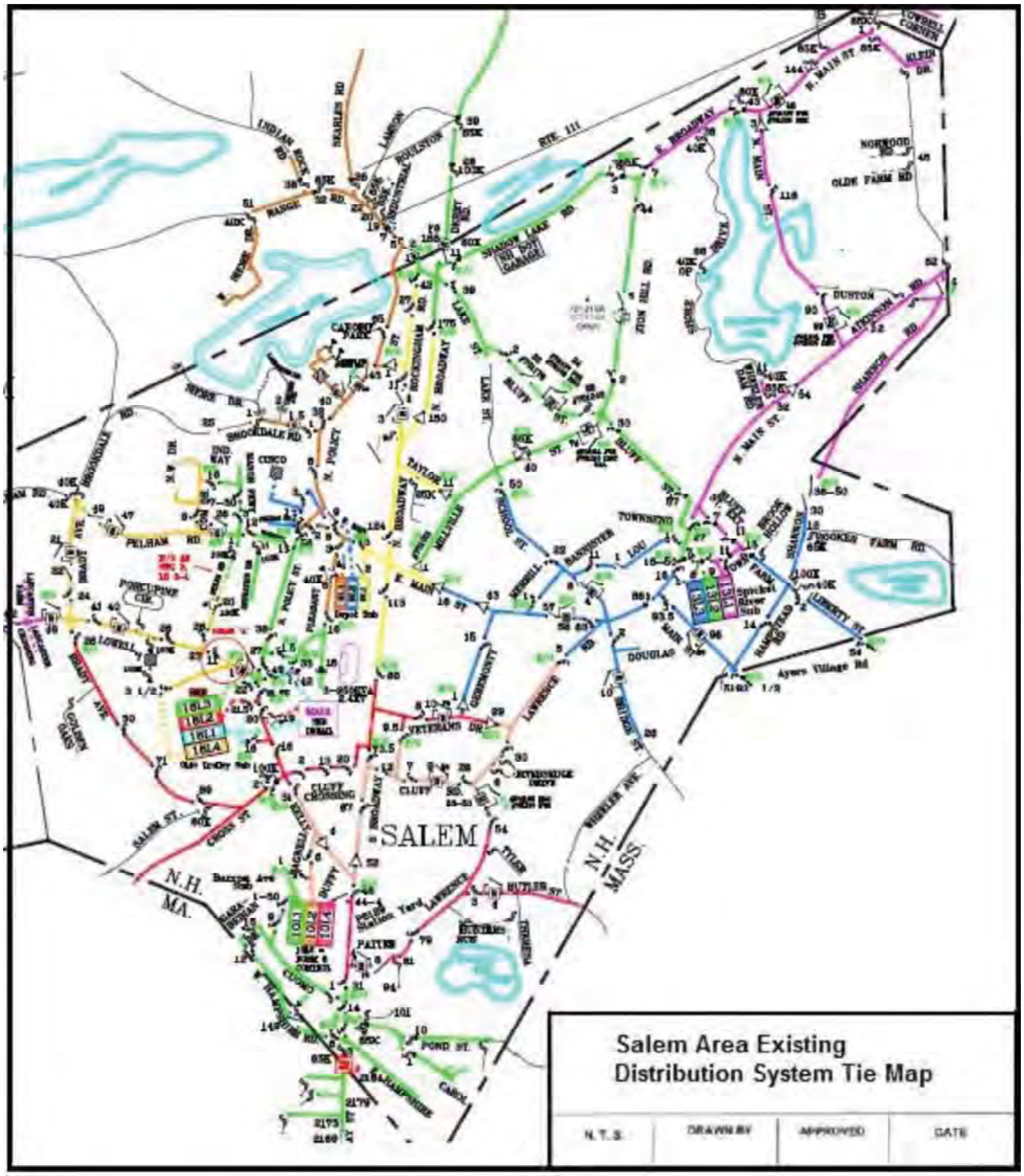


Figure 3 Salem Area 13.2kV Supply System One-line

3.3 Asset Conditions

Existing distribution asset concerns were taken into consideration during this study. The evaluation included the following:

1. Site visits to all Salem area Stations.

2. Review of condition assessment reports provided to Liberty Utilities by National Grid and most recently by United Power Group, INC. See Appendix D for a list of Condition Assessment Reports.

The following is a list of concerns that were documented as part of the Asset Condition evaluation:

1. Barron Ave No. 10 Substation was initially constructed in the early 1960s. It is supplied by the 2393 supply line, which originates from Golden Rock Station, and the National Grid 2353 supply line, which originates from the Methuen No 5 Station. Liberty Utilities has experienced multiple issues with asset concerns at this substation. The 10L1 recloser is 30 years old with an outdated control system (Form 3), the McGraw Edison type VSA has a high failure rate. The 10L4 recloser is 30 years old, this model Kyle recloser is no longer supported with spare parts and the control system has a high failure rate. The regulator contacts are at end of its useful life and the height to live parts inside the substation is below minimum height clearance requirements for a modern substation. It is not considered practical or economic to rebuild the substation in its present location, based upon a benchmark cost of approximately $1 million per feeder position, plus site and supply side construction. Further, capacity is limited to what the Salem 23kV system can provide.

   Additionally, per the 2014 United Power Group, Inc. Asset Condition Report:

   a. The 10L1 – Transformer bushings are showing signs of deterioration; the transformer is over 50 years old.
   b. The 10L2 – 20 Amp Control Circuit Breaker needs replacement.
   c. The 10L4 – Transformer bushings are showing signs of deterioration and are leaking oil around the bottom valve.

2. Salem Depot No. 9 Substation was initially constructed in the 1950's. It is supplied by the 2393 supply line and the 2352 supply line, which originate from Golden Rock Station. The existing 9L1 and 9L2 Breaker Positions and bus are constructed on Wood Pole Structures with limited clearance. This causes reliability and maintenance concerns at the station. It is not considered practical or economic to rebuild the substation in its present

location, based upon a benchmark cost of approximately $1 million per feeder position, plus site and supply side construction. Further, capacity is limited to what the Salem 23kV system can provide.

Additionally, per the 2014 United Power Group, Inc. Asset Condition Report:

a. The 9L3 Transformer 9T3's H3 bushing is showing signs of deterioration.

3. Per the National Grid Asset Condition Report (08/26/2006);
    a. The Olde Trolley 18L2 A and C phase regulator tanks are severely rusted. The regulators will require replacement with 10 years.

3.4 Present Loading and Load Growth

The study was conducted using load data beginning with the recorded 2016 peak load; refer to Table 1 Salem 2016 Peak Load.

Station	*Circuit*	*2016 Peak Load (Amps)*
BARRON AVENUE 10	10L1	197
BARRON AVENUE 10	10L2	312
BARRON AVENUE 10	10L4	229
OLDE TROLLEY 18	18L1	280
OLDE TROLLEY 18	18L2	366
OLDE TROLLEY 18	18L3	321
OLDE TROLLEY 18	18L4	328
SALEM DEPOT 9	9L1	135
SALEM DEPOT 9	9L2	284
SALEM DEPOT 9	9L3	346
SPICKET RIVER 13	13L1	304
SPICKET RIVER 13	13L2	424
SPICKET RIVER 13	13L3	362
Golden Rock	2352	816
Golden Rock	2393	946

Table 1 Salem Area 2016 Peak Load

Anticipated large customer spot loads were also added to the evaluation, refer to Table 2 Spot Loads. The Distribution System was modelled and analyzed using the CYME application to perform the load flow analysis.

Year	*Distribution Circuit*	*Location*	*Load (Amps)*
2017	9L1	Rockingham Park North	104
2017	9L3	Rockingham Park North	32
2018	18L2	Rockingham Park South	13
2018	9L3	Windham Economic Development I	66
2018	9L3	Windham Economic Development II	66
2018	18L3	Rockingham Park South	186
2019	18L2	Rockingham Park South	88
2019	18L3	Rockingham Park South	110
2019	9L1	Rockingham Park South	50
2019	9L2	Rockingham Park South	35

Table 2 Salem Area Spot Loads

The load was escalated through 2031 using the Summer Township Normal – Salem NH load growth data provided by Liberty Utilities; refer to Table 3 Summer Township Normal Load Growth - Salem, NH.

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Summer Township Normal - Salem NH

PSA	Town	Year	MW	% Increase
Eastern Geco	Salem, NH	2016	71.96	
Eastern Geco	Salem, NH	2017	72.46	0.69%
Eastern Geco	Salem, NH	2018	73.04	0.80%
Eastern Geco	Salem, NH	2019	73.58	0.75%
Eastern Geco	Salem, NH	2020	73.95	0.50%
Eastern Geco	Salem, NH	2021	74.23	0.38%
Eastern Geco	Salem, NH	2022	74.54	0.43%
Eastern Geco	Salem, NH	2023	74.91	0.49%
Eastern Geco	Salem, NH	2024	75.25	0.46%
Eastern Geco	Salem, NH	2025	75.57	0.43%
Eastern Geco	Salem, NH	2026	75.90	0.44%
Eastern Geco	Salem, NH	2027	76.24	0.45%
Eastern Geco	Salem, NH	2028	76.60	0.47%
Eastern Geco	Salem, NH	2029	76.97	0.49%
Eastern Geco	Salem, NH	2030	77.36	0.50%
Eastern Geco	Salem, NH	2031	77.76	0.50%

Table 3 Summer Township Normal Load Growth - Salem, NH

Liberty Utilities New Hampshire

Final Seasonal Peak Forecasts 2018-2034

Prepared By

Business Economic Analysis and Research

January 2019

Summary of Results

The weather adjusted actual seasonal peaks appear in Table 1 below for Liberty Utilities New Hampshire (LUNH). Note that the peak load series reflects the historic impacts of both energy efficiency programs and distributed generation activities in the LUNH service territory. Since the forecast is based on normal weather conditions, weather adjusting actual peaks enhances comparisons between historic and forecasted peaks.

Table 1
Historic Weather Adjusted Peaks

year	Summer month	Wthr Adj Peak Mw	Growth	Winter month	Wthr Adj Peak Mw	Growth
2004	7	184.555		12	151.111	
2005	7	193.986	5.11%	12	162.349	7.44%
2006	7	186.673	-3.77%	1	152.805	-5.88%
2007	7	187.153	0.26%	12	152.433	-0.24%
2008	7	194.86	4.12%	12	146.156	-4.12%
2009	7	190.024	-2.48%	12	153.679	5.15%
2010	7	188.816	-0.64%	12	148.528	-3.35%
2011	8	200.696	6.29%	2	151.769	2.18%
2012	8	189.021	-5.82%	1	152.708	0.62%
2013	7	194.125	2.70%	12	155.566	1.87%
2014	7	200.63	3.35%	1	158.976	2.19%
2015	7	184.56	-8.01%	1	148.31	-6.71%
2016	7	187.134	1.39%	1	144.578	-2.52%
2017	8	185.065	-1.11%	12	144.559	-0.01%
2013-2017 Avg			-0.42%			-1.07%

The summer peak has dropped .42% per year over the past five years compared to the winter peak declining 1.07% annually over the same period.

Table 2 displays the LUNH 2018-2034 seasonal peak forecasts under normal peak day weather conditions. The forecasted peak values include the historic impacts from both energy efficiency programs and distributed generation activities in the LUNH service territory. The 2018 growth is based on the 2017 weather adjusted actual shown in Table 1.

Table 2
Forecasted Peaks Normal Weather

	Summer			Winter		
year	month	Peak Mw	Growth	month	Peak Mw	Growth
2018	7	193.324	4.46%	12	149.036	3.10%
2019	7	194.168	0.44%	12	149.322	0.19%
2020	7	194.898	0.38%	12	149.483	0.11%
2021	7	195.572	0.35%	12	149.636	0.10%
2022	7	196.27	0.36%	12	149.836	0.13%
2023	7	196.994	0.37%	12	150.047	0.14%
2024	7	197.702	0.36%	12	150.223	0.12%
2025	7	198.396	0.35%	12	150.4	0.12%
2026	7	199.093	0.35%	12	150.583	0.12%
2027	7	199.797	0.35%	12	150.771	0.12%
2028	7	200.508	0.36%	12	150.969	0.13%
2029	7	201.228	0.36%	12	151.175	0.14%
2030	7	201.957	0.36%	12	151.39	0.14%
2031	7	202.693	0.36%	12	151.61	0.15%
2032	7	203.433	0.37%	12	151.834	0.15%
2033	7	204.177	0.37%	12	152.063	0.15%
2034	7	204.927	0.37%	12	152.298	0.15%
2020-2024 Avg			0.36%			0.12%

The average annual summer growth rate in peak for 2020-2024 is .36% while the winter average annual growth rate is .12% over the same period.

Table 3 provides the LUNH 2018-2034 seasonal peak forecasts under extreme weather. Although the peaks are higher, the annual growth rates for 2020-2024 are just less than the growth rates using normal weather.

Table 3
Forecasted Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	212.317		12	155.069	
2019	7	213.19	0.41%	12	155.355	0.18%
2020	7	213.95	0.36%	12	155.516	0.10%
2021	7	214.653	0.33%	12	155.669	0.10%
2022	7	215.38	0.34%	12	155.87	0.13%
2023	7	216.133	0.35%	12	156.08	0.13%
2024	7	216.87	0.34%	12	156.256	0.11%
2025	7	217.593	0.33%	12	156.433	0.11%
2026	7	218.32	0.33%	12	156.616	0.12%
2027	7	219.052	0.34%	12	156.804	0.12%
2028	7	219.793	0.34%	12	157.002	0.13%
2029	7	220.542	0.34%	12	157.208	0.13%
2030	7	221.299	0.34%	12	157.423	0.14%
2031	7	222.064	0.35%	12	157.644	0.14%
2032	7	222.833	0.35%	12	157.867	0.14%
2033	7	223.607	0.35%	12	158.096	0.15%
2034	7	224.386	0.35%	12	158.331	0.15%
2020-2024 Avg			0.35%			0.12%

In previous peak day studies performed by National Grid, Eastern PSA and Western PSA hourly data was the source of historic peak day analysis and subsequent forecasts. In this study, LUNH system hourly data was the only source of historic peak day analysis. Once the LUNH system seasonal peak day forecasts were developed in this analysis, Eastern PSA and Western PSA forecasts were derived by using the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018. Table 4 below reveals the Eastern PSA seasonal forecasts under normal weather conditions.

Table 4
Eastern PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	97.8993		12	71.0305	
2019	7	98.3267	0.44%	12	71.1669	0.19%
2020	7	98.6964	0.38%	12	71.2435	0.11%
2021	7	99.0377	0.35%	12	71.3165	0.10%
2022	7	99.391	0.36%	12	71.4118	0.13%
2023	7	99.7577	0.37%	12	71.5125	0.14%
2024	7	100.1162	0.36%	12	71.5963	0.12%
2025	7	100.4677	0.35%	12	71.6807	0.12%
2026	7	100.8208	0.35%	12	71.7679	0.12%
2027	7	101.1773	0.35%	12	71.8575	0.12%
2028	7	101.5373	0.36%	12	71.9518	0.13%
2029	7	101.9018	0.36%	12	72.05	0.14%
2030	7	102.271	0.36%	12	72.1524	0.14%
2031	7	102.6437	0.36%	12	72.2574	0.15%
2032	7	103.0185	0.37%	12	72.3641	0.15%
2033	7	103.3952	0.37%	12	72.4733	0.15%
2034	7	103.775	0.37%	12	72.5852	0.15%
2020-2024 Avg			0.36%			0.12%

Table 5 lists the Western PSA seasonal forecasts under normal weather conditions. The Eastern PSA numbers are slightly higher than the Western peak day values in the summer but somewhat lower in the winter months.

Table 5
Western PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	95.4248		12	78.0054	
2019	7	95.8414	0.44%	12	78.1554	0.19%
2020	7	96.2016	0.38%	12	78.2394	0.11%
2021	7	96.5343	0.35%	12	78.3194	0.10%
2022	7	96.8789	0.36%	12	78.4242	0.13%
2023	7	97.2362	0.37%	12	78.5347	0.14%
2024	7	97.5858	0.36%	12	78.6266	0.12%
2025	7	97.9284	0.35%	12	78.7195	0.12%
2026	7	98.2723	0.35%	12	78.8148	0.12%
2027	7	98.6199	0.35%	12	78.9135	0.13%
2028	7	98.9709	0.36%	12	79.0173	0.13%
2029	7	99.3262	0.36%	12	79.1251	0.14%
2030	7	99.6859	0.36%	12	79.2376	0.14%
2031	7	100.0491	0.36%	12	79.3526	0.15%
2032	7	100.4148	0.37%	12	79.4698	0.15%
2033	7	100.7816	0.37%	12	79.5897	0.15%
2034	7	101.1519	0.37%	12	79.7129	0.15%
2020-2024 Avg			0.36%			0.12%

Tables 6 and 7 provide the Eastern PSA and Western PSA seasonal forecasts under extreme weather conditions. As the case with the normal weather forecasts, The Eastern PSA values are higher than the Western PSA numbers in the summer but lower during the winter period.

Table 6
Eastern PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	107.5173		12	73.9059	
2019	7	107.9595	0.41%	12	74.0422	0.18%
2020	7	108.3443	0.36%	12	74.119	0.10%
2021	7	108.7002	0.33%	12	74.1918	0.10%
2022	7	109.0684	0.34%	12	74.2877	0.13%
2023	7	109.4498	0.35%	12	74.3876	0.13%
2024	7	109.823	0.34%	12	74.4716	0.11%
2025	7	110.189	0.33%	12	74.556	0.11%
2026	7	110.5572	0.33%	12	74.6433	0.12%
2027	7	110.9279	0.34%	12	74.7328	0.12%
2028	7	111.3032	0.34%	12	74.8272	0.13%
2029	7	111.6825	0.34%	12	74.9254	0.13%
2030	7	112.0658	0.34%	12	75.0278	0.14%
2031	7	112.4532	0.35%	12	75.1331	0.14%
2032	7	112.8427	0.35%	12	75.2394	0.14%
2033	7	113.2346	0.35%	12	75.3486	0.15%
2034	7	113.629	0.35%	12	75.4606	0.15%
2020-2024 Avg			0.35%			0.12%

Table 7
Western PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	104.7997		12	81.1631	
2019	7	105.2306	0.41%	12	81.3128	0.18%
2020	7	105.6058	0.36%	12	81.3971	0.10%
2021	7	105.9527	0.33%	12	81.4771	0.10%
2022	7	106.3115	0.34%	12	81.5821	0.13%
2023	7	106.6833	0.35%	12	81.6922	0.13%
2024	7	107.047	0.34%	12	81.7843	0.11%
2025	7	107.4041	0.33%	12	81.8771	0.11%
2026	7	107.7628	0.33%	12	81.9728	0.12%
2027	7	108.1243	0.34%	12	82.0713	0.12%
2028	7	108.4899	0.34%	12	82.175	0.13%
2029	7	108.8596	0.34%	12	82.2826	0.13%
2030	7	109.2332	0.34%	12	82.3951	0.14%
2031	7	109.6111	0.35%	12	82.5109	0.14%
2032	7	109.9904	0.35%	12	82.6275	0.14%
2033	7	110.3723	0.35%	12	82.7473	0.14%
2034	7	110.7569	0.35%	12	82.8704	0.15%
2020-2024 Avg			0.35%			0.12%

The report describes the analytical approach employed in developing the seasonal LUNH forecasts and details the data available for the analysis.

Introduction

This report presents the Liberty Utilities New Hampshire (LUNH) seasonal peak forecasts for 2018-2034 under both normal and extreme weather. Regression analysis was used to estimate the LUNH historic monthly peak day model. The historic monthly peaks were net of all energy efficiency and distributed generation load impacts. The monthly peak day model coefficients were then employed to develop seasonal peak forecasts at the LUNH system level. The LUNH system seasonal peak forecasts were then split into Eastern and Western jurisdictions using LUNH township sales information as well the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018.

The remainder of this report is organized as follows. First, the data used in the analysis is described. Second, the regression model specifications are provided. Third, the results from the regression models are discussed. Finally, the 2018-2034 seasonal forecast process is detailed.

Data

There were three data sources employed to perform the historic peak day modeling. These sources include LUNH hourly load and annual township sales, economic drivers for the LUNH service area, and daily weather information.

Hourly system load for LUNH from October 2000 through April 2014 was supplied by National Grid while historic system loads from May 2014 through October 2018 was provided by LUNH staff. LUNH also supplied hourly Eastern and Western PSA loads for March 2014 through October 2018. The historic peak load data includes the impacts of energy efficiency programs as well as distributed generation activities. Also, National Grid supplied annual sales data for 21 townships from 1996 through 2013 and 2014-2017 township volumes came from LUNH. The 2014-2017 township volumes collapsed 2 small townships into larger ones so the 1996 through 2013 data was aggregated as well down to 19 townships.

The system load and annual township sales information was utilized to create the dependent variables for the various regression models estimated. For the monthly peak day analysis, the maximum hourly load for each month from October 2000 through October 2018 was identified as the dependent variable (LUNH staff requested not using 2002-2003 peak day values). A total of 193 months of peaks are used in the peak day analysis. Each of the 19 townships has 22 years of annual sales in the annual usage analysis. Appendix A contains the historic monthly peak values for LUNH.

Annual employment and number of households for Rockingham and Grafton counties from 1970 through 2043 was purchased from Moody's Economy.com to develop an economic variable for the monthly peak model. Employment and household values were summed across the two counties. Each series was then divided by the 2017 employment and household value to create annual ratios. The annual ratios were then combined using a 60% weight for employment and 40% weight for households based on previous work performed by National Grid. The annual ratios were converted to monthly numbers over the historic and forecast period by spreading the annual growth rate into 12 equal parts. Appendix B reveals the annual total employment and total households for Rockingham and Grafton counties from 2000 to 2034 along with the development of the annual employment/household ratio term.

Weather information came from NOAA. Daily high temperature, low temperature, and dew point temperature information from the Concord New Hampshire Airport (WBAN #14745) was obtained for March 1994 through October 2018. Using the above mentioned weather elements, the temperature humidity index (THI) and heating degree days (HDD) were used in the peak day modeling analysis while annual cooling degree days (CDD) was used when modeling annual township sales. The discussion of how each specific weather element is computed resides in the model specification section of this report.

Specification of Models

This section first provides the specification of the peak day model followed by a description of the annual township sales models.

Peak Day Model Specification

The monthly peak day usage was primarily driven by weather conditions. The most important weather term was the temperature humidity index (THI). The daily THI was defined as follows:

THI = .55 * maximum temperature + .2 * average dew point temperature + 17.5

A weighted THI variable (WTHI) was used in the model to account for the heat buildup impact on energy usage. The WTHI equaled:

WTHI = .7 * THI on the peak day + .2 * THI day before + .1 * THI two days before

In addition to the WTHI term, a summer period (June through September) indicator was interacted with the WTHI as follows:

WTHI_SUMMER = WTHI * summer period

To account for the increased saturation of air conditioning in the service territory, the WTHI_SUMMER term defined above was also interacted with a time trend term (the value of the trend started at 1 in year 2000 and increased to 19 in year 2018) as described below:

WTHI_SUMMER_T = WTHI_SUMMER * time trend

The coefficient values of three THI terms defined above are expected to be positive in the regression model based on the assumption that the higher the WTHI value, the higher the peak day value will be. To account for peaks during the winter period, a heating degree day (HDD) term was added based on the maximum daily temperature on the peak day, the day before the peak, and two days prior to the peak (WTMAX). WTMAX equaled:

WTMAX = .7*max temp on peak day + 2*max temp day before +.1*max temp 2 days before

The term HDD was defined as

HDD = (55 – WTMAX), or 0 if the value of WTMAX was greater than or equal to 55

The expected value of the HDD coefficient in the regression equation is greater than zero which suggests the peak day use rises as the temperature becomes colder. The economic variable included in the peak day model was the weighted employment and household (EMP_HH) index variable discussed in the previous section of this report. EMP_HH was defined as

EMP_HH = .6 * employment index + .4 * household index

The index portion of this variable was computed by dividing the actual employment and household count variables by the 2017 values. It is expected that a positive relationship exists between peak day use and the value of the index. The remaining variables included in the peak day model were monthly indicators. These indicators take the value of one for a particular month, zero otherwise. The monthly indicators included are as follows:

FEB = one if month is February, zero otherwise

MAR = one if month is March, zero otherwise

APR = one if month is April, zero otherwise

MAY = one if month is May, zero otherwise

JUN = one if month is June, zero otherwise

JUL = one if month is July, zero otherwise

AUG = one if month is August, zero otherwise

SEP = one if month is September, zero otherwise

OCT = one if month is October, zero otherwise

NOV = one if month is November, zero otherwise

DEC = one if month is December, zero otherwise

The final LUNH peak day model expressed in mathematical terms is as follows:

PeakDay Mw = a + b * WTHI + c * WTHI_SUMMER + d * WTHI_SUMMER_T
+ e * HDD + f * EMP_HH + g * FEB + h * MAR + i * APR + j * MAY
+ k * JUN + l * JUL + m * AUG + n * SEP + o * OCT + p * NOV
+ q * DEC

Values of the estimated coefficients (a, b …, q) will be presented and discussed in the next section of the report.

Annual Township Sales Model Specification

The principal factor that influences annual sales at the township level has been a time trend that takes the value of one in 1996 and increases to twenty two in 2017. In order to flatten the change in township usage over the historic period, the time trend variable was expressed as a log function. The trend term variable was expressed as follows:

TIME = log(time trend value + 1)

The value of TIME is expected to have a positive coefficient value if the township experienced sales growth from 1996 through 2017 and a negative value if township sales declined from 1996 through 2017. The other term included in the annual township sales models was annual cooling degree days (CDD). CDD was based on the average daily temperature (daily maximum temperature plus daily minimum temperature divided by two). Daily cooling degree days was defined as:

CDD = (average temp – 60), or 0 if the average temp was less than or equal to 60.

The daily CDD values were then summed for the entire calendar year for final inclusion into the township models. It was expected that a positive relationship existed between CDD and annual sales. Township regression models that generated a negative coefficient for CDD had that variable removed from the analysis. The final LUNH annual township models expressed in mathematical terms are as follows:

Annual kWh = a + b * TIME + c * CDD

Values of the estimated coefficients (a, b, and c) will be presented and discussed in the next section of the report.

Regression Results

This section provides the overall model statistics as well as estimated coefficient values for the peak day and annual township models. The peak day model adjusted R-Squared value was .8750 which means that almost 88% of the monthly historic peak day variation was explained by the model coefficients. The monthly peak day Mw model coefficients are as follows:

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|
INTERCEPT	64.86846	23.20202	2.8	0.0058
WTHI	0.85693	0.20588	4.16	<.0001
WTHI_SUMMER	3.1535	0.46812	6.74	<.0001
WTHI_SUMMER_T	0.00632	0.00306	2.06	0.0406
HDD	0.96711	0.23931	4.04	<.0001
EMP_HH	24.462	21.59604	1.13	0.2589
FEB	-4.66736	2.84739	-1.64	0.103
MAR	-8.22188	3.20446	-2.57	0.0111
APR	-17.97462	4.53312	-3.97	0.0001
MAY	-2.41446	5.41104	-0.45	0.656
JUN	-239.189	36.00799	-6.64	<.0001
JUL	-234.42314	36.64564	-6.4	<.0001
AUG	-234.567	36.24369	-6.47	<.0001
SEP	-241.3816	35.23254	-6.85	<.0001
OCT	-13.51145	4.82839	-2.8	0.0057
NOV	-5.35602	4.05034	-1.32	0.1878
DEC	2.16819	2.96977	0.73	0.4663

The values of the WTHI terms have the expected positive coefficient signs and significant. The HDD term also has a significant expected positive coefficient sign. Likewise, the EMP_HH term has an insignificant expected positive coefficient sign and the coefficient value is smaller than in previous models. Only the MAY, NOV and DEC monthly terms are not significant at the 80% level. The JUN through SEP indicators have large negative values to offset the impact of the WTHI_SUMMER and WTHI_SUMMER_T terms.

The Eastern area annual kWh models by township appear as follows:

Eastern Township Regression Results

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Derry					R-Square	0.1887
INTERCEPT	-1835369	2055463	-0.89	0.3831		
TIME	693431	390994	1.77	0.0922		
CDD	2451.71302	2090.285	1.17	0.2553		
Town=Pelham					R-Square	0.843
INTERCEPT	23190627	7417272	3.13	0.0056		
TIME	12696638	1410926	9	<.0001		
CDD	16722	7542.929	2.22	0.039		
Town=Salem, NH					R-Square	0.3481
Intercept	260455731	18672477	13.95	<.0001		
TIME	4661243	3489929	1.34	0.1983		
CDD	23524	19167	1.23	0.2355		
YEAR 2005	27801238	10711572	2.6	0.0183		
Town=Windham					R-Square	0.7684
INTERCEPT	8359128	1308965	6.39	<.0001		
TIME	1749608	248994	7.03	<.0001		
CDD	2533.59809	1331.141	1.9	0.0723		

Note that the Salem Township had a year 2005 indicator variable added to capture a spike in annual usage for that year. All the CDD terms were significant at the 75% confidence level which is reasonable for a twenty two year historic series.

Western area annual kWh models by township are displayed below. The Grafton Township had a year 2002 indicator variable to capture a spike in usage for that year and Monroe Township had inserted a year 2015 indicator variable to capture a sharp decline in usage for that year.

Western Township Regression Results #1

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Acworth					R-Square	0.2872
INTERCEPT	1138893	40922	27.83	<.0001		
TIME	51619	16782	3.08	0.006		
Town=Alstead					R-Square	0.2703
INTERCEPT	9911652	279550	35.46	<.0001		
TIME	339631	114640	2.96	0.0077		
Town=Bath					R-Square	0.6263
INTERCEPT	-24230	18148	-1.34	0.1976		
TIME	16396	3452.176	4.75	0.0001		
CDD	34.64262	18.45562	1.88	0.0759		
Town=Canaan					R-Square	0.5829
INTERCEPT	10109160	992313	10.19	<.0001		
TIME	939189	188760	4.98	<.0001		
CDD	626.87929	1009.124	0.62	0.5418		
Town=Charlestown, NH					R-Square	0.662
INTERCEPT	1341700	7090630	0.19	0.8519		
TIME	7708582	1348792	5.72	<.0001		
CDD	7084.15717	7210.754	0.98	0.3382		
Town=Cornish					R-Square	0.2728
INTERCEPT	737101	125034	5.9	<.0001		
TIME	60214	23784	2.53	0.0203		
CDD	106.30368	127.1522	0.84	0.4135		

Western Township Regression Results #2

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Enfield					R-Square	0.696
INTERCEPT	14777186	1182050	12.5	<.0001		
TIME	1424926	224852	6.34	<.0001		
CDD	816.14872	1202.076	0.68	0.5054		
Town=Grafton, NH					R-Square	0.2885
INTERCEPT	58659	6089.404	9.63	<.0001		
TIME	1831.8423	2481.113	0.74	0.4693		
YEAR 2002	25472	7934.861	3.21	0.0046		
Town=Hanover, NH					R-Square	0.7912
INTERCEPT	71690818	10136017	7.07	<.0001		
TIME	15531554	1928091	8.06	<.0001		
CDD	9687.25295	10308	0.94	0.3591		
Town=Lebanon					R-Square	0.8205
INTERCEPT	75964275	26385845	2.88	0.0096		
TIME	41806548	5019161	8.33	<.0001		
CDD	54227	26833	2.02	0.0576		
Town=Marlow					R-Square	0.1333
INTERCEPT	27954	7196.082	3.88	0.001		
TIME	2734.8391	1368.851	2	0.0602		
CDD	2.38771	7.31799	0.33	0.7478		

Western Township Regression Results #3

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Monroe, NH					R-Square	0.0412
INTERCEPT	1749590	49783	35.14	<.0001		
TIME	10203	20693	0.49	0.6276		
YEAR 2015	-112537	66177	-1.7	0.1053		
Town=Plainfield					R-Square	0.4926
INTERCEPT	4730329	569497	8.31	<.0001		
TIME	417108	108331	3.85	0.0011		
CDD	691.89342	579.1449	1.19	0.2469		
Town=Surry					R-Square	0.5655
INTERCEPT	126126	47772	2.64	0.0161		
TIME	44633	9087.18	4.91	<.0001		
CDD	18.33472	48.58082	0.38	0.7101		
Town=Walpole					R-Square	0.4369
INTERCEPT	22018299	1526600	14.42	<.0001		
TIME	1065108	290392	3.67	0.0016		
CDD	1156.39317	1552.462	0.74	0.4655		

Except for Grafton, all the western area townships had significant time trend coefficients at the 90% confidence level. All of the larger usage Western Townships had CDD coefficients significant at the 70% confidence level.

An explanation of how the peak day and township model coefficients are employed to generate seasonal peak day forecasts appears in the next section.

Seasonal Forecast Development for 2018-2034

The peak day model coefficients detailed in the previous section of the report are used along with the economic driver forecast (shown in Appendix B) and normal/extreme weather to estimate seasonal peak forecasts for 2018 through 2034. The normal monthly WTHI and HDD values were computed by taking the average values for those terms during the October 2000 through September 2018 LUNH system monthly peak days. The extreme monthly WTHI and HDD values were extracted by taking the maximum values for those monthly terms during the October 2000 through September 2018 LUNH system monthly peak days. The normal and extreme monthly WTHI and HDD values appear below.

	Weather Values Used in Forecast			
Month	Normal WTHI	Extreme WTHI	Normal HDD	Extreme HDD
January	30.315	21.9	34.7444	45
February	34.0047	26.995	29.9167	38.1
March	39.7611	30.86	22.3111	32.6
April	62.9111	78.18	5.0389	25.1
May	75.9147	81.925	0	0
June	80.3658	84.525	0	0
July	81.8786	86.475	0	0
August	80.9872	84.61	0	0
September	78.1219	82.16	0	0
October	67.4789	75.035	1.3737	10.7
November	48.2356	37.26	12.0667	23.8
December	37.5533	21.37	25.8222	46.4

The normal and extreme LUNH system seasonal peak day forecasts appear in Tables 2 and 3 in the Summary of Results section of the report. The system peak day values were allocated to the Eastern and Western PSA regions by using the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018. The summer Eastern coincident peak proportion was 50.64% while the Western proportion was 49.36%. The winter Eastern coincident peak contribution was 46.66% compared to the Western value of 53.34%. Appendix C lists the Eastern and Western coincident peak contributions for March 2014 through October 2018.

The individual township peaks were then calculated by utilizing the annual township sales regression models. For townships with CDD in the model, normal CDD value equaled 1057 and the extreme CDD took the value of 1265 which were computed based upon 1998 through 2017 Concord weather data. Once the annual township forecasts were completed, they were totaled so that individual township annual proportions under normal and extreme weather could be applied to the area peak values.

The Derry township results are shown below. The annual growth rates for 2020-2024 are much larger than the overall system average.

Derry Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.7228		0.5244		0.9092		0.625	
2019	0.7314	1.19%	0.5294	0.95%	0.9186	1.03%	0.63	0.80%
2020	0.7394	1.09%	0.5337	0.81%	0.9273	0.95%	0.6344	0.70%
2021	0.747	1.03%	0.5379	0.79%	0.9355	0.88%	0.6385	0.65%
2022	0.7545	1.00%	0.5421	0.78%	0.9437	0.88%	0.6428	0.67%
2023	0.762	0.99%	0.5463	0.77%	0.9519	0.87%	0.6469	0.64%
2024	0.7693	0.96%	0.5502	0.71%	0.9598	0.83%	0.6508	0.60%
2025	0.7764	0.92%	0.5539	0.67%	0.9675	0.80%	0.6546	0.58%
2026	0.7834	0.90%	0.5576	0.67%	0.9751	0.79%	0.6584	0.58%
2027	0.7903	0.88%	0.5613	0.66%	0.9827	0.78%	0.662	0.55%
2028	0.7971	0.86%	0.5648	0.62%	0.9901	0.75%	0.6656	0.54%
2029	0.8038	0.84%	0.5684	0.64%	0.9975	0.75%	0.6692	0.54%
2030	0.8105	0.83%	0.5718	0.60%	1.0048	0.73%	0.6727	0.52%
2031	0.8172	0.83%	0.5753	0.61%	1.0121	0.73%	0.6762	0.52%
2032	0.8238	0.81%	0.5786	0.57%	1.0193	0.71%	0.6796	0.50%
2033	0.8303	0.79%	0.582	0.59%	1.0264	0.70%	0.683	0.50%
2034	0.8367	0.77%	0.5853	0.57%	1.0335	0.69%	0.6864	0.50%
2020-2024 Avg		1.04%		0.79%		0.90%		0.66%

The Pelham township results are provided next. The 2020-2024 annual growth rates for Pelham are not as large as Derry but larger than the overall system.

Pelham Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	19.8326		14.3895		22.193		15.2552	
2019	20.006	0.87%	14.4799	0.63%	22.3766	0.83%	15.3466	0.60%
2020	20.1645	0.79%	14.5557	0.52%	22.545	0.75%	15.4232	0.50%
2021	20.3145	0.74%	14.6283	0.50%	22.7043	0.71%	15.4965	0.48%
2022	20.4642	0.74%	14.7034	0.51%	22.8634	0.70%	15.5725	0.49%
2023	20.6143	0.73%	14.7776	0.50%	23.0226	0.70%	15.6473	0.48%
2024	20.7604	0.71%	14.8464	0.47%	23.1777	0.67%	15.7169	0.44%
2025	20.903	0.69%	14.9137	0.45%	23.329	0.65%	15.7849	0.43%
2026	21.044	0.67%	14.9799	0.44%	23.4787	0.64%	15.8518	0.42%
2027	21.1839	0.66%	15.0451	0.44%	23.627	0.63%	15.9177	0.42%
2028	21.3228	0.66%	15.1099	0.43%	23.7745	0.62%	15.9832	0.41%
2029	21.4611	0.65%	15.1742	0.43%	23.9211	0.62%	16.0482	0.41%
2030	21.599	0.64%	15.2381	0.42%	24.067	0.61%	16.1128	0.40%
2031	21.7361	0.63%	15.3014	0.42%	24.2123	0.60%	16.1769	0.40%
2032	21.8725	0.63%	15.3641	0.41%	24.3567	0.60%	16.2402	0.39%
2033	22.008	0.62%	15.4262	0.40%	24.5003	0.59%	16.303	0.39%
2034	22.1431	0.61%	15.4879	0.40%	24.6432	0.58%	16.3654	0.38%
2020-2024 Avg		0.75%		0.51%		0.72%		0.48%

Salem forecasts are displayed next. The Salem annual growth rates are lower than the overall system rates and since Salem contributes the most to Eastern PSA total, Salem pushes down the Eastern PSA numbers that appear in Tables 4 through 7 in the Summary of Results section.

Salem Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	73.2909		53.176		79.9279		54.9413	
2019	73.5093	0.30%	53.2046	0.05%	80.1487	0.28%	54.9687	0.05%
2020	73.6882	0.24%	53.1915	-0.02%	80.3308	0.23%	54.9548	-0.03%
2021	73.8492	0.22%	53.1784	-0.02%	80.4952	0.20%	54.9409	-0.03%
2022	74.0223	0.23%	53.1845	0.01%	80.6718	0.22%	54.9464	0.01%
2023	74.2081	0.25%	53.1969	0.02%	80.8613	0.23%	54.9575	0.02%
2024	74.3905	0.25%	53.199	0.00%	81.0475	0.23%	54.9588	0.00%
2025	74.5701	0.24%	53.2035	0.01%	81.2311	0.23%	54.9625	0.01%
2026	74.7531	0.25%	53.212	0.02%	81.4187	0.23%	54.9702	0.01%
2027	74.9408	0.25%	53.224	0.02%	81.6104	0.24%	54.9814	0.02%
2028	75.1331	0.26%	53.2412	0.03%	81.8076	0.24%	54.9978	0.03%
2029	75.3306	0.26%	53.2627	0.04%	82.0097	0.25%	55.0185	0.04%
2030	75.5332	0.27%	53.2889	0.05%	82.2167	0.25%	55.0439	0.05%
2031	75.7401	0.27%	53.3182	0.05%	82.4283	0.26%	55.0727	0.05%
2032	75.9499	0.28%	53.3501	0.06%	82.6431	0.26%	55.1034	0.06%
2033	76.1627	0.28%	53.385	0.07%	82.8612	0.26%	55.1375	0.06%
2034	76.379	0.28%	53.4231	0.07%	83.0826	0.27%	55.1748	0.07%
2020-2024 Avg		0.24%		0.00%		0.22%		0.00%

The last Eastern PSA township, Windham, forecasts are displayed next. The annual growth rate in peaks for Windham from 2020-2024 are somewhat higher than the overall system average.

Windham Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	4.053		2.9406		4.4872		3.0844	
2019	4.08	0.67%	2.953	0.42%	4.5156	0.63%	3.0969	0.41%
2020	4.1043	0.60%	2.9626	0.33%	4.5412	0.57%	3.1066	0.31%
2021	4.127	0.55%	2.9719	0.31%	4.5652	0.53%	3.1159	0.30%
2022	4.15	0.56%	2.9818	0.33%	4.5895	0.53%	3.126	0.32%
2023	4.1733	0.56%	2.9917	0.33%	4.614	0.53%	3.1359	0.32%
2024	4.196	0.54%	3.0007	0.30%	4.638	0.52%	3.1451	0.29%
2025	4.2182	0.53%	3.0096	0.30%	4.6614	0.50%	3.154	0.28%
2026	4.2403	0.52%	3.0184	0.29%	4.6847	0.50%	3.1629	0.28%
2027	4.2623	0.52%	3.0271	0.29%	4.7078	0.49%	3.1717	0.28%
2028	4.2843	0.52%	3.0359	0.29%	4.731	0.49%	3.1806	0.28%
2029	4.3063	0.51%	3.0447	0.29%	4.7542	0.49%	3.1895	0.28%
2030	4.3283	0.51%	3.0536	0.29%	4.7773	0.49%	3.1984	0.28%
2031	4.3503	0.51%	3.0625	0.29%	4.8005	0.49%	3.2073	0.28%
2032	4.3723	0.51%	3.0713	0.29%	4.8236	0.48%	3.2162	0.28%
2033	4.3942	0.50%	3.0801	0.29%	4.8467	0.48%	3.2251	0.28%
2034	4.4162	0.50%	3.0889	0.29%	4.8697	0.47%	3.234	0.28%
2020-2024 Avg		0.57%		0.32%		0.54%		0.31%

The Western Township forecasts are shown next starting with Acworth. The Acworth annual growth rates are much lower than the overall system for 2020-2024.

Acworth Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.242		0.1979		0.258		0.1998	
2019	0.2422	0.08%	0.1975	-0.20%	0.2581	0.04%	0.1995	-0.15%
2020	0.2422	0.00%	0.197	-0.25%	0.2581	0.00%	0.199	-0.25%
2021	0.2421	-0.04%	0.1965	-0.25%	0.2581	0.00%	0.1985	-0.25%
2022	0.2422	0.04%	0.1961	-0.20%	0.2581	0.00%	0.1981	-0.20%
2023	0.2423	0.04%	0.1957	-0.20%	0.2582	0.04%	0.1977	-0.20%
2024	0.2424	0.04%	0.1953	-0.20%	0.2583	0.04%	0.1974	-0.15%
2025	0.2425	0.04%	0.195	-0.15%	0.2585	0.08%	0.197	-0.20%
2026	0.2427	0.08%	0.1946	-0.21%	0.2586	0.04%	0.1967	-0.15%
2027	0.2429	0.08%	0.1943	-0.15%	0.2588	0.08%	0.1964	-0.15%
2028	0.2431	0.08%	0.1941	-0.10%	0.259	0.08%	0.1962	-0.10%
2029	0.2433	0.08%	0.1938	-0.15%	0.2592	0.08%	0.1959	-0.15%
2030	0.2436	0.12%	0.1936	-0.10%	0.2595	0.12%	0.1957	-0.10%
2031	0.2439	0.12%	0.1934	-0.10%	0.2598	0.12%	0.1955	-0.10%
2032	0.2442	0.12%	0.1932	-0.10%	0.2601	0.12%	0.1954	-0.05%
2033	0.2445	0.12%	0.1931	-0.05%	0.2604	0.12%	0.1952	-0.10%
2034	0.2449	0.16%	0.193	-0.05%	0.2608	0.15%	0.1951	-0.05%
2020-2024 Avg		0.02%		-0.22%		0.02%		-0.21%

Alstead township forecast appears next. As the case with Acworth, Alstead annual growth in peak is much lower than the system average.

Alstead Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	2.0418		1.6691		2.1768		1.6858	
2019	2.042	0.01%	1.6652	-0.23%	2.1768	0.00%	1.682	-0.23%
2020	2.0414	-0.03%	1.6603	-0.29%	2.1761	-0.03%	1.6772	-0.29%
2021	2.0406	-0.04%	1.6555	-0.29%	2.1751	-0.05%	1.6726	-0.27%
2022	2.0403	-0.01%	1.6516	-0.24%	2.1747	-0.02%	1.6688	-0.23%
2023	2.0405	0.01%	1.6481	-0.21%	2.1748	0.00%	1.6654	-0.20%
2024	2.0409	0.02%	1.6444	-0.22%	2.1751	0.01%	1.6618	-0.22%
2025	2.0413	0.02%	1.6409	-0.21%	2.1755	0.02%	1.6584	-0.20%
2026	2.042	0.03%	1.6377	-0.20%	2.1761	0.03%	1.6553	-0.19%
2027	2.043	0.05%	1.6348	-0.18%	2.177	0.04%	1.6524	-0.18%
2028	2.0442	0.06%	1.6321	-0.17%	2.1781	0.05%	1.6498	-0.16%
2029	2.0457	0.07%	1.6297	-0.15%	2.1796	0.07%	1.6474	-0.15%
2030	2.0475	0.09%	1.6275	-0.13%	2.1812	0.07%	1.6453	-0.13%
2031	2.0495	0.10%	1.6255	-0.12%	2.1832	0.09%	1.6434	-0.12%
2032	2.0517	0.11%	1.6237	-0.11%	2.1853	0.10%	1.6416	-0.11%
2033	2.054	0.11%	1.6221	-0.10%	2.1876	0.11%	1.64	-0.10%
2034	2.0565	0.12%	1.6206	-0.09%	2.19	0.11%	1.6386	-0.09%
2020-2024 Avg		-0.01%		-0.25%		-0.02%		-0.24%

The Bath township forecasts are displayed below. The annual growth in the Bath peaks from 2020-2024 is higher than the system average although the peaks are very small.

			Bath Township Peaks					
	Summer		Winter		Summer		Winter	
	Normal		Normal		Extreme		Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	0.012		0.0098		0.0142		0.011	
2019	0.0121	0.83%	0.0099	1.02%	0.0143	0.70%	0.0111	0.91%
2020	0.0122	0.83%	0.0099	0.00%	0.0144	0.70%	0.0111	0.00%
2021	0.0123	0.82%	0.01	1.01%	0.0145	0.69%	0.0112	0.90%
2022	0.0124	0.81%	0.01	0.00%	0.0146	0.69%	0.0112	0.00%
2023	0.0125	0.81%	0.0101	1.00%	0.0147	0.68%	0.0113	0.89%
2024	0.0126	0.80%	0.0101	0.00%	0.0148	0.68%	0.0113	0.00%
2025	0.0127	0.79%	0.0102	0.99%	0.0149	0.68%	0.0114	0.88%
2026	0.0127	0.00%	0.0102	0.00%	0.015	0.67%	0.0114	0.00%
2027	0.0128	0.79%	0.0103	0.98%	0.0151	0.67%	0.0115	0.88%
2028	0.0129	0.78%	0.0103	0.00%	0.0152	0.66%	0.0115	0.00%
2029	0.013	0.78%	0.0104	0.97%	0.0153	0.66%	0.0115	0.00%
2030	0.0131	0.77%	0.0104	0.00%	0.0154	0.65%	0.0116	0.87%
2031	0.0132	0.76%	0.0104	0.00%	0.0154	0.00%	0.0116	0.00%
2032	0.0133	0.76%	0.0105	0.96%	0.0155	0.65%	0.0117	0.86%
2033	0.0133	0.00%	0.0105	0.00%	0.0156	0.65%	0.0117	0.00%
2034	0.0134	0.75%	0.0106	0.95%	0.0157	0.64%	0.0118	0.85%
2020-2024 Avg		0.83%		0.40%		0.70%		0.36%

Forecasts for the Canaan Township appear below. The annual growth rate in Canaan is less than the system average during the 2020-2024 years.

Canaan Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	2.5555		2.089		2.7503		2.13	
2019	2.5597	0.16%	2.0874	-0.08%	2.7545	0.15%	2.1284	-0.08%
2020	2.5627	0.12%	2.0842	-0.15%	2.7575	0.11%	2.1254	-0.14%
2021	2.5652	0.10%	2.0812	-0.14%	2.7601	0.09%	2.1225	-0.14%
2022	2.5683	0.12%	2.079	-0.11%	2.7632	0.11%	2.1204	-0.10%
2023	2.5719	0.14%	2.0773	-0.08%	2.7669	0.13%	2.1187	-0.08%
2024	2.5756	0.14%	2.0752	-0.10%	2.7706	0.13%	2.1167	-0.09%
2025	2.5792	0.14%	2.0733	-0.09%	2.7743	0.13%	2.1149	-0.09%
2026	2.5831	0.15%	2.0716	-0.08%	2.7782	0.14%	2.1133	-0.08%
2027	2.5872	0.16%	2.0702	-0.07%	2.7824	0.15%	2.112	-0.06%
2028	2.5915	0.17%	2.0691	-0.05%	2.7869	0.16%	2.1109	-0.05%
2029	2.5962	0.18%	2.0682	-0.04%	2.7916	0.17%	2.11	-0.04%
2030	2.601	0.18%	2.0675	-0.03%	2.7965	0.18%	2.1094	-0.03%
2031	2.6061	0.20%	2.067	-0.02%	2.8017	0.19%	2.109	-0.02%
2032	2.6114	0.20%	2.0667	-0.01%	2.807	0.19%	2.1087	-0.01%
2033	2.6168	0.21%	2.0665	-0.01%	2.8125	0.20%	2.1086	0.00%
2034	2.6224	0.21%	2.0666	0.00%	2.8182	0.20%	2.1086	0.00%
2020-2024 Avg		0.12%		-0.12%		0.12%		-0.11%

The Charlestown township forecasts are shown next below. The annual growth rate in peak forecasts is higher than the system average during the 2020-2024 years.

Charlestown Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	6.1913		5.0611		6.8924		5.3379	
2019	6.2426	0.83%	5.0906	0.58%	6.9461	0.78%	5.3673	0.55%
2020	6.2892	0.75%	5.1149	0.48%	6.9951	0.71%	5.3916	0.45%
2021	6.3331	0.70%	5.1381	0.45%	7.0412	0.66%	5.4147	0.43%
2022	6.3769	0.69%	5.1622	0.47%	7.0872	0.65%	5.4387	0.44%
2023	6.4208	0.69%	5.1858	0.46%	7.1333	0.65%	5.4623	0.43%
2024	6.4634	0.66%	5.2077	0.42%	7.178	0.63%	5.4841	0.40%
2025	6.5049	0.64%	5.2289	0.41%	7.2216	0.61%	5.5053	0.39%
2026	6.5458	0.63%	5.2498	0.40%	7.2647	0.60%	5.5261	0.38%
2027	6.5864	0.62%	5.2703	0.39%	7.3073	0.59%	5.5466	0.37%
2028	6.6268	0.61%	5.2907	0.39%	7.3497	0.58%	5.567	0.37%
2029	6.6669	0.61%	5.3109	0.38%	7.3918	0.57%	5.5872	0.36%
2030	6.7068	0.60%	5.3311	0.38%	7.4338	0.57%	5.6073	0.36%
2031	6.7466	0.59%	5.351	0.37%	7.4755	0.56%	5.6273	0.36%
2032	6.7861	0.59%	5.3706	0.37%	7.5169	0.55%	5.6469	0.35%
2033	6.8253	0.58%	5.3901	0.36%	7.5581	0.55%	5.6664	0.35%
2034	6.8644	0.57%	5.4095	0.36%	7.5991	0.54%	5.6858	0.34%
2020-2024 Avg		0.71%		0.46%		0.67%		0.44%

The Cornish township forecast numbers are displayed next. The annual growth in Cornish peaks is less than the 2020-2024 system average growth.

	Cornish Township Peaks							
	Summer Normal		Winter Normal		Summer Extreme		Winter Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	0.1934		0.1581		0.2105		0.163	
2019	0.1936	0.10%	0.1579	-0.13%	0.2107	0.10%	0.1628	-0.12%
2020	0.1937	0.05%	0.1576	-0.19%	0.2109	0.09%	0.1625	-0.18%
2021	0.1938	0.05%	0.1573	-0.19%	0.211	0.05%	0.1622	-0.18%
2022	0.194	0.10%	0.1571	-0.13%	0.2111	0.05%	0.162	-0.12%
2023	0.1942	0.10%	0.1569	-0.13%	0.2113	0.09%	0.1618	-0.12%
2024	0.1944	0.10%	0.1566	-0.19%	0.2116	0.14%	0.1616	-0.12%
2025	0.1946	0.10%	0.1565	-0.06%	0.2118	0.09%	0.1614	-0.12%
2026	0.1949	0.15%	0.1563	-0.13%	0.212	0.09%	0.1613	-0.06%
2027	0.1951	0.10%	0.1561	-0.13%	0.2122	0.09%	0.1611	-0.12%
2028	0.1954	0.15%	0.156	-0.06%	0.2125	0.14%	0.161	-0.06%
2029	0.1957	0.15%	0.1559	-0.06%	0.2128	0.14%	0.1609	-0.06%
2030	0.196	0.15%	0.1558	-0.06%	0.2131	0.14%	0.1608	-0.06%
2031	0.1963	0.15%	0.1557	-0.06%	0.2135	0.19%	0.1607	-0.06%
2032	0.1967	0.20%	0.1556	-0.06%	0.2138	0.14%	0.1606	-0.06%
2033	0.197	0.15%	0.1556	0.00%	0.2142	0.19%	0.1606	0.00%
2034	0.1974	0.20%	0.1556	0.00%	0.2145	0.14%	0.1605	-0.06%
2020-2024 Avg		0.08%		-0.16%		0.09%		-0.15%

Enfield Township seasonal peak forecasts are listed next. Much like Cornish, the annual 2020-2024 growth in Enfield peaks is lower than the system average numbers.

Enfield Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	3.7467		3.0627		4.0279		3.1195	
2019	3.7532	0.17%	3.0606	-0.07%	4.0345	0.16%	3.1175	-0.06%
2020	3.7579	0.13%	3.0562	-0.14%	4.0393	0.12%	3.1133	-0.13%
2021	3.7619	0.11%	3.0521	-0.13%	4.0434	0.10%	3.1093	-0.13%
2022	3.7667	0.13%	3.0492	-0.10%	4.0483	0.12%	3.1066	-0.09%
2023	3.7723	0.15%	3.0468	-0.08%	4.0541	0.14%	3.1044	-0.07%
2024	3.778	0.15%	3.044	-0.09%	4.0598	0.14%	3.1017	-0.09%
2025	3.7836	0.15%	3.0414	-0.09%	4.0656	0.14%	3.0993	-0.08%
2026	3.7895	0.16%	3.0392	-0.07%	4.0716	0.15%	3.0972	-0.07%
2027	3.7959	0.17%	3.0374	-0.06%	4.0781	0.16%	3.0954	-0.06%
2028	3.8025	0.17%	3.0359	-0.05%	4.0849	0.17%	3.0941	-0.04%
2029	3.8095	0.18%	3.0348	-0.04%	4.092	0.17%	3.093	-0.04%
2030	3.8169	0.19%	3.034	-0.03%	4.0995	0.18%	3.0923	-0.02%
2031	3.8246	0.20%	3.0334	-0.02%	4.1074	0.19%	3.0919	-0.01%
2032	3.8326	0.21%	3.0332	-0.01%	4.1154	0.19%	3.0916	-0.01%
2033	3.8407	0.21%	3.0331	0.00%	4.1238	0.20%	3.0916	0.00%
2034	3.8491	0.22%	3.0333	0.01%	4.1323	0.21%	3.0919	0.01%
2020-2024 Avg		0.13%		-0.11%		0.13%		-0.10%

Grafton Township forecast results are provided below. Annual growth in Grafton peaks is lower than the system average.

Grafton Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.012		0.0098		0.0128		0.0099	
2019	0.012	0.00%	0.0098	0.00%	0.0128	0.00%	0.0099	0.00%
2020	0.012	0.00%	0.0097	-1.02%	0.0128	0.00%	0.0098	-1.01%
2021	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2022	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2023	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2024	0.012	0.00%	0.0096	-1.03%	0.0128	0.00%	0.0097	-1.02%
2025	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2026	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2027	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2028	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2029	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2030	0.012	0.00%	0.0095	-1.04%	0.0128	0.00%	0.0096	-1.03%
2031	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2032	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2033	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2034	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2020-2024 Avg		0.00%		-0.41%		0.00%		-0.40%

The Hanover township forecasts appear next. As one of the larger Western PSA townships, the Hanover annual growth rate from 2020-2024 is slightly lower than the system average growth.

Hanover Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	24.3897		19.9375		26.401		20.4465	
2019	24.4794	0.37%	19.9621	0.12%	26.4937	0.35%	20.472	0.12%
2020	24.5554	0.31%	19.9706	0.04%	26.5731	0.30%	20.4816	0.05%
2021	24.6251	0.28%	19.9786	0.04%	26.646	0.27%	20.4907	0.04%
2022	24.6984	0.30%	19.9935	0.07%	26.7225	0.29%	20.5065	0.08%
2023	24.7754	0.31%	20.0103	0.08%	26.8027	0.30%	20.524	0.09%
2024	24.851	0.31%	20.0229	0.06%	26.8813	0.29%	20.5374	0.07%
2025	24.9253	0.30%	20.0361	0.07%	26.9587	0.29%	20.5514	0.07%
2026	25.0003	0.30%	20.0504	0.07%	27.037	0.29%	20.5665	0.07%
2027	25.0767	0.31%	20.0658	0.08%	27.1163	0.29%	20.5825	0.08%
2028	25.1543	0.31%	20.0829	0.09%	27.197	0.30%	20.6002	0.09%
2029	25.2333	0.31%	20.1013	0.09%	27.279	0.30%	20.6192	0.09%
2030	25.3138	0.32%	20.1212	0.10%	27.3624	0.31%	20.6396	0.10%
2031	25.3955	0.32%	20.1421	0.10%	27.447	0.31%	20.6611	0.10%
2032	25.478	0.32%	20.1637	0.11%	27.5324	0.31%	20.683	0.11%
2033	25.5612	0.33%	20.1863	0.11%	27.6186	0.31%	20.706	0.11%
2034	25.6454	0.33%	20.2098	0.12%	27.7057	0.32%	20.7299	0.12%
2020-2024 Avg		0.30%		0.06%		0.29%		0.06%

Lebanon township seasonal peak forecasts are listed next. As the largest Western PSA township, Lebanon peak growth from 2020-2024 is somewhat higher than the overall system growth.

	Lebanon Township Peaks							
	Summer		Winter		Summer		Winter	
	Normal		Normal		Extreme		Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	49.4416		40.4163		54.9438		42.5517	
2019	49.7017	0.53%	40.53	0.28%	55.2134	0.49%	42.664	0.26%
2020	49.9308	0.46%	40.608	0.19%	55.4519	0.43%	42.7403	0.18%
2021	50.1438	0.43%	40.6822	0.18%	55.674	0.40%	42.813	0.17%
2022	50.3613	0.43%	40.7679	0.21%	55.9007	0.41%	42.8976	0.20%
2023	50.5842	0.44%	40.8552	0.21%	56.1328	0.42%	42.9834	0.20%
2024	50.8016	0.43%	40.9318	0.19%	56.3593	0.40%	43.0588	0.18%
2025	51.0141	0.42%	41.0076	0.19%	56.5811	0.39%	43.1334	0.17%
2026	51.2263	0.42%	41.0839	0.19%	56.8028	0.39%	43.2086	0.17%
2027	51.4393	0.42%	41.1607	0.19%	57.0247	0.39%	43.2844	0.18%
2028	51.6531	0.42%	41.2393	0.19%	57.248	0.39%	43.3621	0.18%
2029	51.8683	0.42%	41.3192	0.19%	57.4725	0.39%	43.4412	0.18%
2030	52.085	0.42%	41.4009	0.20%	57.6982	0.39%	43.5221	0.19%
2031	52.3027	0.42%	41.4832	0.20%	57.9253	0.39%	43.604	0.19%
2032	52.5208	0.42%	41.5659	0.20%	58.1526	0.39%	43.6857	0.19%
2033	52.7391	0.42%	41.6494	0.20%	58.3806	0.39%	43.7686	0.19%
2034	52.9584	0.42%	41.7339	0.20%	58.6093	0.39%	43.8526	0.19%
2020-2024 Avg		0.44%		0.20%		0.42%		0.19%

Marlow township forecast values are shown next. The Marlow growth is much lower than the system average during the 2020-2024 years.

	Marlow Township Peaks							
	Summer		Winter		Summer		Winter	
	Normal		Normal		Extreme		Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	0.0073		0.0059		0.0079		0.0061	
2019	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2020	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2021	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2022	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2023	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2024	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.006	-1.64%
2025	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.006	0.00%
2026	0.0074	1.37%	0.0059	0.00%	0.0079	0.00%	0.006	0.00%
2027	0.0074	0.00%	0.0059	0.00%	0.008	1.27%	0.006	0.00%
2028	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2029	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2030	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2031	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2032	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2033	0.0075	1.35%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2034	0.0075	0.00%	0.0059	0.00%	0.0081	1.25%	0.006	0.00%
2020-2024 Avg		0.00%		0.00%		0.00%		-0.33%

Monroe township peak forecasts are shown below. The annual growth in Monroe Township is smaller than the system average during the 2020-2024 years.

	Monroe Township Peaks							
	Summer		Winter		Summer		Winter	
	Normal		Normal		Extreme		Extreme	
year	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth	Peak Mw	Growth
2018	0.331		0.2706		0.3529		0.2733	
2019	0.3307	-0.09%	0.2697	-0.33%	0.3526	-0.09%	0.2724	-0.33%
2020	0.3303	-0.12%	0.2686	-0.41%	0.3521	-0.14%	0.2714	-0.37%
2021	0.3299	-0.12%	0.2676	-0.37%	0.3516	-0.14%	0.2704	-0.37%
2022	0.3295	-0.12%	0.2667	-0.34%	0.3512	-0.11%	0.2695	-0.33%
2023	0.3293	-0.06%	0.2659	-0.30%	0.3509	-0.09%	0.2687	-0.30%
2024	0.329	-0.09%	0.2651	-0.30%	0.3507	-0.06%	0.2679	-0.30%
2025	0.3289	-0.03%	0.2643	-0.30%	0.3505	-0.06%	0.2672	-0.26%
2026	0.3287	-0.06%	0.2636	-0.26%	0.3503	-0.06%	0.2665	-0.26%
2027	0.3286	-0.03%	0.2629	-0.27%	0.3502	-0.03%	0.2658	-0.26%
2028	0.3286	0.00%	0.2623	-0.23%	0.3501	-0.03%	0.2652	-0.23%
2029	0.3286	0.00%	0.2617	-0.23%	0.3501	0.00%	0.2646	-0.23%
2030	0.3286	0.00%	0.2612	-0.19%	0.3501	0.00%	0.2641	-0.19%
2031	0.3287	0.03%	0.2607	-0.19%	0.3502	0.03%	0.2636	-0.19%
2032	0.3288	0.03%	0.2603	-0.15%	0.3503	0.03%	0.2631	-0.19%
2033	0.329	0.06%	0.2598	-0.19%	0.3504	0.03%	0.2627	-0.15%
2034	0.3292	0.06%	0.2594	-0.15%	0.3506	0.06%	0.2623	-0.15%
2020-2024 Avg		-0.10%		-0.34%		-0.11%		-0.33%

Plainfield township forecasts appear next. The Plainfield growth rate is peak from 2020-2024 is much lower than the system average over this time frame.

Plainfield Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	1.2609		1.0307		1.3727		1.0631	
2019	1.2626	0.13%	1.0296	-0.11%	1.3744	0.12%	1.062	-0.10%
2020	1.2637	0.09%	1.0278	-0.17%	1.3755	0.08%	1.0602	-0.17%
2021	1.2646	0.07%	1.026	-0.18%	1.3764	0.07%	1.0584	-0.17%
2022	1.2658	0.09%	1.0247	-0.13%	1.3776	0.09%	1.0571	-0.12%
2023	1.2673	0.12%	1.0236	-0.11%	1.3791	0.11%	1.056	-0.10%
2024	1.2688	0.12%	1.0223	-0.13%	1.3806	0.11%	1.0548	-0.11%
2025	1.2704	0.13%	1.0212	-0.11%	1.3821	0.11%	1.0536	-0.11%
2026	1.272	0.13%	1.0201	-0.11%	1.3837	0.12%	1.0526	-0.09%
2027	1.2738	0.14%	1.0192	-0.09%	1.3855	0.13%	1.0517	-0.09%
2028	1.2757	0.15%	1.0185	-0.07%	1.3874	0.14%	1.0509	-0.08%
2029	1.2777	0.16%	1.0178	-0.07%	1.3895	0.15%	1.0503	-0.06%
2030	1.2799	0.17%	1.0173	-0.05%	1.3917	0.16%	1.0497	-0.06%
2031	1.2821	0.17%	1.0169	-0.04%	1.394	0.17%	1.0493	-0.04%
2032	1.2845	0.19%	1.0166	-0.03%	1.3964	0.17%	1.049	-0.03%
2033	1.2869	0.19%	1.0163	-0.03%	1.3988	0.17%	1.0487	-0.03%
2034	1.2895	0.20%	1.0162	-0.01%	1.4014	0.19%	1.0486	-0.01%
2020-2024 Avg		0.10%		-0.14%		0.09%		-0.14%

Surry Township forecast values are listed next. The annual growth in the Surry peak from 2020-2024 is higher than the system average.

Surry Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.0534		0.0436		0.0577		0.0447	
2019	0.0537	0.56%	0.0438	0.46%	0.058	0.52%	0.0448	0.22%
2020	0.0539	0.37%	0.0438	0.00%	0.0582	0.34%	0.0449	0.22%
2021	0.0541	0.37%	0.0439	0.23%	0.0584	0.34%	0.0449	0.00%
2022	0.0544	0.55%	0.044	0.23%	0.0587	0.51%	0.045	0.22%
2023	0.0546	0.37%	0.0441	0.23%	0.0589	0.34%	0.0451	0.22%
2024	0.0548	0.37%	0.0442	0.23%	0.0592	0.51%	0.0452	0.22%
2025	0.0551	0.55%	0.0443	0.23%	0.0594	0.34%	0.0453	0.22%
2026	0.0553	0.36%	0.0443	0.00%	0.0597	0.51%	0.0454	0.22%
2027	0.0555	0.36%	0.0444	0.23%	0.0599	0.34%	0.0455	0.22%
2028	0.0557	0.36%	0.0445	0.23%	0.0601	0.33%	0.0455	0.00%
2029	0.056	0.54%	0.0446	0.22%	0.0604	0.50%	0.0456	0.22%
2030	0.0562	0.36%	0.0447	0.22%	0.0606	0.33%	0.0457	0.22%
2031	0.0564	0.36%	0.0448	0.22%	0.0609	0.50%	0.0458	0.22%
2032	0.0567	0.53%	0.0448	0.00%	0.0611	0.33%	0.0459	0.22%
2033	0.0569	0.35%	0.0449	0.22%	0.0613	0.33%	0.046	0.22%
2034	0.0571	0.35%	0.045	0.22%	0.0616	0.49%	0.0461	0.22%
2020-2024 Avg		0.41%		0.18%		0.41%		0.18%

The final township, Walpole forecasts of peak appear below. The Walpole average annual growth is less than the system average for the 2020-2024 years.

Walpole Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	4.9462		4.0433		5.3208		4.1208	
2019	4.9486	0.05%	4.0354	-0.20%	5.3228	0.04%	4.113	-0.19%
2020	4.9489	0.01%	4.0249	-0.26%	5.3229	0.00%	4.1027	-0.25%
2021	4.9485	-0.01%	4.0148	-0.25%	5.3222	-0.01%	4.0928	-0.24%
2022	4.9494	0.02%	4.0066	-0.20%	5.3229	0.01%	4.0847	-0.20%
2023	4.9516	0.04%	3.9993	-0.18%	5.3249	0.04%	4.0775	-0.18%
2024	4.954	0.05%	3.9915	-0.20%	5.327	0.04%	4.0699	-0.19%
2025	4.9565	0.05%	3.9843	-0.18%	5.3294	0.05%	4.0628	-0.17%
2026	4.9596	0.06%	3.9776	-0.17%	5.3324	0.06%	4.0562	-0.16%
2027	4.9633	0.07%	3.9716	-0.15%	5.336	0.07%	4.0503	-0.15%
2028	4.9677	0.09%	3.9661	-0.14%	5.3402	0.08%	4.0449	-0.13%
2029	4.9726	0.10%	3.9613	-0.12%	5.345	0.09%	4.0401	-0.12%
2030	4.9781	0.11%	3.957	-0.11%	5.3504	0.10%	4.0359	-0.10%
2031	4.9841	0.12%	3.9531	-0.10%	5.3564	0.11%	4.0321	-0.09%
2032	4.9906	0.13%	3.9496	-0.09%	5.3628	0.12%	4.0287	-0.08%
2033	4.9974	0.14%	3.9466	-0.08%	5.3696	0.13%	4.0256	-0.08%
2034	5.0047	0.15%	3.944	-0.07%	5.3768	0.13%	4.023	-0.06%
2020-2024 Avg		0.02%		-0.22%		0.02%		-0.21%

APPENDIX A

	LUNH Historic Peak Day Values

year	month	day	hour	Mw
2000	10	30	18	120.587
2000	11	21	18	132.537
2000	12	14	18	133.21
2001	1	10	18	130.276
2001	2	22	19	131.967
2001	3	1	19	117.486
2001	4	24	14	125.857
2001	5	11	16	134.29
2001	6	27	16	159.728
2001	7	24	15	168.319
2001	8	6	14	173.866
2001	9	10	15	142.882
2001	10	4	14	121.58
2001	11	29	18	126.458
2001	12	17	18	137.219
2004	1	14	19	150.948
2004	2	17	19	138.039
2004	3	16	19	135.111
2004	4	30	15	126.933
2004	5	12	16	137.766
2004	6	9	15	166.476
2004	7	22	14	172.492
2004	8	3	15	169.516
2004	9	17	14	141.094
2004	10	8	15	124.583
2004	11	17	18	140.077
2004	12	21	19	151.159
2005	1	18	19	148.961
2005	2	21	19	137.439
2005	3	9	19	141.04
2005	4	20	13	125.3
2005	5	11	15	127.421
2005	6	27	15	184.603
2005	7	19	14	191.871
2005	8	10	16	179.92
2005	9	14	16	158.878
2005	10	25	19	145.312
2005	11	23	18	135.463
2005	12	13	18	161.546
2006	1	23	19	149.003
2006	2	8	19	139.41
2006	3	1	19	134.011
2006	4	4	20	123.651
2006	5	31	17	147.724
2006	6	19	13	181.58
2006	7	18	16	191.959
2006	8	2	15	195.419

2006	9	18	16	138.005
2006	10	4	20	126.699
2006	11	30	18	132.703
2006	12	4	18	146.719
2007	1	26	18	141.539
2007	2	5	19	146.216
2007	3	6	19	144.084
2007	4	4	19	130.327
2007	5	25	16	148.856
2007	6	27	14	187.416
2007	7	27	14	178.707
2007	8	3	15	187.522
2007	9	7	16	165.591
2007	10	22	19	150.267
2007	11	26	18	139.867
2007	12	5	18	152.389
2008	1	3	18	144.175
2008	2	1	18	139.664
2008	3	5	19	132.501
2008	4	23	16	127.896
2008	5	27	14	135.302
2008	6	10	15	195.262
2008	7	8	15	186.04
2008	8	18	16	159.613
2008	9	5	15	163.176
2008	10	9	20	127.515
2008	11	5	18	133.241
2008	12	8	18	146.578
2009	1	14	18	147.427
2009	2	5	19	142.883
2009	3	2	19	138.703
2009	4	28	15	140.767
2009	5	21	16	145.009
2009	6	26	13	145.615
2009	7	29	15	176.68
2009	8	18	14	190.698
2009	9	3	16	139.939
2009	10	28	19	131.489
2009	11	30	18	136.288
2009	12	17	18	154.02
2010	1	12	18	143.943
2010	2	4	19	140.447
2010	3	3	19	131.958
2010	4	7	20	124.039
2010	5	26	16	174.742
2010	6	28	14	171.967
2010	7	7	16	196.543
2010	8	31	17	187.363

2010	9	1	16	186.389
2010	10	1	10	139.359
2010	11	29	18	138.456
2010	12	15	18	149.16
2011	1	24	19	150.041
2011	2	2	18	155.316
2011	3	21	20	144.149
2011	4	28	12	140.458
2011	5	31	16	162.456
2011	6	9	15	183.139
2011	7	22	15	205.939
2011	8	1	15	186.77
2011	9	14	14	157.534
2011	10	10	16	139.923
2011	11	28	18	138.63
2011	12	19	18	146.848
2012	1	16	18	150.194
2012	2	29	19	139.924
2012	3	1	19	140.808
2012	4	16	18	142.882
2012	5	31	14	149.487
2012	6	21	16	192.762
2012	7	17	17	191.846
2012	8	3	16	188.008
2012	9	7	16	165.842
2012	10	15	19	137.546
2012	11	7	18	141.017
2012	12	16	18	149.861
2013	1	24	18	154.659
2013	2	5	19	146.904
2013	3	7	19	139.796
2013	4	12	14	130.322
2013	5	31	16	182.108
2013	6	24	12	191.469
2013	7	19	13	203.761
2013	8	21	17	181.325
2013	9	11	16	191.313
2013	10	2	15	140.756
2013	11	25	18	145.9
2013	12	17	19	159.28
2014	1	2	18	161.33
2014	2	11	19	145.35
2014	3	3	19	144.09
2014	4	15	14	122.63
2014	5	12	16	133.566
2014	6	30	17	172.905
2014	7	23	16	193.21
2014	8	27	16	175.731

2014	9	2	15	177.966
2014	10	16	12	134.995
2014	11	18	18	135.778
2014	12	8	18	143.234
2015	1	8	18	148.541
2015	2	16	19	144.885
2015	3	5	19	137.502
2015	4	2	11	123.717
2015	5	27	16	159.605
2015	6	23	17	149.229
2015	7	30	14	184.893
2015	8	18	14	186.141
2015	9	9	16	187.326
2015	10	13	19	153.086
2015	11	30	18	131.008
2015	12	29	18	133.603
2016	1	9	18	142.592
2016	2	15	18	142.576
2016	3	3	19	129.165
2016	4	4	12	125.539
2016	5	31	16	152.579
2016	6	20	16	167.76
2016	7	28	15	185.985
2016	8	12	16	193.151
2016	9	9	16	176.143
2016	10	17	19	125.149
2016	11	21	18	128.994
2016	12	19	18	143.2
2017	1	9	18	143.485
2017	2	7	19	134.572
2017	3	4	19	127.668
2017	4	11	16	124.478
2017	5	18	16	162.931
2017	6	12	17	181.34
2017	7	20	15	179.727
2017	8	22	17	179.089
2017	9	25	16	172.378

2017	10	9	19	136
2017	11	28	18	129.146
2017	12	28	18	150.426
2018	1	2	18	154.265
2018	2	7	18	135.615
2018	3	7	18	127.866
2018	4	16	12	121.766
2018	5	31	18	145.275
2018	6	18	16	170.718
2018	7	3	14	194.416
2018	8	29	15	197.82
2018	9	5	16	185.689
2018	10	10	16	141.038

Appendix B

Rockingham and Grafton Economic Variabls

Year	Employment	Households	Ratio Employment	Ratio Households	EMP_HH
2000	187.909556	136.67992	0.883437547	0.868487589	0.878499
2001	190.210754	138.994921	0.894256394	0.883197501	0.890603
2002	188.792392	141.139531	0.88758811	0.89682472	0.890639
2003	188.11389	142.7048	0.884398203	0.906770707	0.891788
2004	192.798123	144.091146	0.906420645	0.915579786	0.909446
2005	195.972244	145.783314	0.92134345	0.926332111	0.922991
2006	198.973063	147.631915	0.935451493	0.938078438	0.936319
2007	200.824353	148.693788	0.944155144	0.944825761	0.944377
2008	200.732851	150.063565	0.943724956	0.953529558	0.946964
2009	194.529293	150.820776	0.914559563	0.958341006	0.929022
2010	195.290864	151.627674	0.918140011	0.963468174	0.933113
2011	196.932633	151.990988	0.92585862	0.965776733	0.939045
2012	199.207744	153.358134	0.936554822	0.974463813	0.949077
2013	201.188058	154.136489	0.945865066	0.979409614	0.956946
2014	203.497594	153.967144	0.956723113	0.978333567	0.963862
2015	206.784935	154.604545	0.97217821	0.982383722	0.975549
2016	209.789856	155.970247	0.986305539	0.991061626	0.987877
2017	212.702705	157.376941	1	1	1
2018	216.594529	159.020301	1.018297012	1.010442191	1.015702
2019	219.530696	160.178698	1.032101101	1.017802843	1.027378
2020	220.939724	161.212455	1.038725502	1.024371512	1.033984
2021	222.306633	162.130018	1.045151885	1.030201864	1.040214
2022	224.20116	163.196886	1.054058809	1.036980926	1.048418
2023	226.155081	164.359214	1.063244969	1.044366557	1.057009
2024	227.736127	165.42675	1.070678095	1.051149863	1.064227
2025	229.310686	166.501942	1.078080723	1.057981817	1.071442
2026	230.937906	167.622535	1.085730931	1.065102257	1.078917
2027	232.615046	168.783076	1.093615833	1.072476533	1.086633
2028	234.367337	169.997032	1.10185405	1.080190217	1.094698
2029	236.235999	171.209275	1.110639373	1.087893016	1.103126
2030	238.188653	172.464594	1.119819576	1.095869528	1.111908
2031	240.21632	173.724622	1.129352445	1.103875961	1.120937
2032	242.281408	174.98734	1.139061245	1.111899487	1.130089
2033	244.416009	176.245366	1.149096853	1.1198932	1.13945
2034	246.633113	177.497101	1.159520341	1.127846938	1.149058

Appendix C

year	month	day	hour	system mw	psa total	mw_e	mw_w	Eastern %	Western %
2014	3	3	19	144.09	144.0875	66.7299	77.3576	46.31%	53.69%
2014	4	15	14	122.63	122.6254	50.2352	72.3902	40.96%	59.04%
2014	5	12	16	133.566	133.5654	57.9524	75.613	43.39%	56.61%
2014	6	30	17	172.905	156.8357	69.5198	87.3159	40.21%	59.79%
2014	7	23	16	193.213	193.2128	96.326	96.8868	49.85%	50.15%
2014	8	27	16	175.731	175.7307	87.134	88.5967	49.58%	50.42%
2014	9	2	15	177.966	177.966	87.896	90.07	49.39%	50.61%
2014	10	16	12	134.995	134.9956	54.57	80.4256	40.42%	59.58%
2014	11	18	18	135.892	135.8918	62.217	73.6748	45.78%	54.22%
2014	12	8	18	143.321	143.3214	68.071	75.2504	47.50%	52.50%
2015	1	8	18	148.451	148.4504	69.655	78.7954	46.92%	53.08%
2015	2	16	19	144.833	144.8328	68.698	76.1348	47.43%	52.57%
2015	3	5	19	137.502	137.5021	63.046	74.4561	45.85%	54.15%
2015	4	2	11	123.717	123.7167	53.196	70.5207	43.00%	57.00%
2015	5	27	16	173.241	173.2414	80.931	92.3104	46.72%	53.28%
2015	6	23	17	163.897	163.8974	76.974	86.9234	46.96%	53.04%
2015	7	30	14	185.508	185.5081	88.65	96.8581	47.79%	52.21%
2015	8	18	14	186.141	186.141	90.612	95.529	48.68%	51.32%
2015	9	9	16	187.326	187.3256	90.746	96.5796	48.44%	51.56%
2015	10	13	19	126.066	126.0657	54.757	71.3087	43.44%	56.56%
2015	11	30	18	131.179	131.1792	61.125	70.0542	46.60%	53.40%
2015	12	29	18	135.02	135.0195	64.717	70.3025	47.93%	52.07%
2016	1	19	18	142.656	142.6563	66.52	76.1363	46.63%	53.37%
2016	2	15	18	142.576	142.576	66.849	75.727	46.89%	53.11%
2016	3	3	19	129.165	129.1652	58.534	70.6312	45.32%	54.68%
2016	4	4	12	125.627	125.6264	55.789	69.8374	44.41%	55.59%
2016	5	31	16	152.932	152.9326	72.016	80.9166	47.09%	52.91%
2016	6	20	16	168.23	168.2302	80.188	88.0422	47.67%	52.33%

2016	7	28	15	187.268	187.268	92.677	94.591	49.49%	50.51%
2016	8	12	16	193.773	193.7728	101.455	92.3178	52.36%	47.64%
2016	9	9	16	176.143	176.1425	88.094	88.0485	50.01%	49.99%
2016	10	17	19	125.149	125.1491	54.943	70.2061	43.90%	56.10%
2016	11	21	18	128.994	128.9941	59.783	69.2111	46.35%	53.65%
2016	12	19	18	143.2	143.2006	68.277	74.9236	47.68%	52.32%
2017	1	9	18	143.485	143.4859	67	76.4859	46.69%	53.31%
2017	2	7	19	134.572	134.5725	62.075	72.4975	46.13%	53.87%
2017	3	4	19	127.668	127.6675	59.331	68.3365	46.47%	53.53%
2017	4	11	16	124.478	124.4777	53.157	71.3207	42.70%	57.30%
2017	5	18	16	162.931	162.9316	80.043	82.8886	49.13%	50.87%
2017	6	12	17	181.34	181.3401	93.591	87.7491	51.61%	48.39%
2017	7	20	15	179.727	179.7268	89.606	90.1208	49.86%	50.14%
2017	8	22	17	179.089	179.0891	88.946	90.1431	49.67%	50.33%
2017	9	25	16	172.378	172.378	80.833	91.545	46.89%	53.11%
2017	10	9	19	136	136.0002	59.58	76.4202	43.81%	56.19%
2017	11	28	18	129.146	129.1464	60.506	68.6404	46.85%	53.15%
2017	12	28	18	150.426	150.4257	73.259	77.1667	48.70%	51.30%
2018	1	2	18	154.265	154.265	73.013	81.252	47.33%	52.67%
2018	2	7	18	135.615	135.6153	62.193	73.4223	45.86%	54.14%
2018	3	7	18	127.866	127.8662	58.701	69.1652	45.91%	54.09%
2018	4	16	12	121.766	121.7653	54.945	66.8203	45.12%	54.88%
2018	5	31	18	145.275	145.2743	67.507	77.7673	46.47%	53.53%
2018	6	18	16	170.718	170.718	83.684	87.034	49.02%	50.98%
2018	7	3	14	194.416	194.4155	95.599	98.8165	49.17%	50.83%
2018	8	29	15	197.82	197.8195	100.733	97.0865	50.92%	49.08%
2018	9	5	16	185.689	185.6899	90.481	95.2089	48.73%	51.27%
2018	10	10	16	141.038	141.0376	62.74	78.2976	44.48%	55.52%

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

OCA Data Requests - Set 4

Date Request Received: 7/24/19
Request No. OCA 4-6

Date of Response: 8/7/19
Respondent: Joel Rivera

REQUEST:

Provide any documents in the utility's possession describing any internal processes or software systems the utility uses to manage risk, including:

a. How the utility identifies potential risks;

b. How the utility estimates the probable incidence of each potential risk;

c. How the utility estimates the likely consequences of each incident;

d. How the utility estimates the financial impact associated with an incident;

e. How the utility employs these risk identification and estimation processes in distribution investment decisions.

RESPONSE:

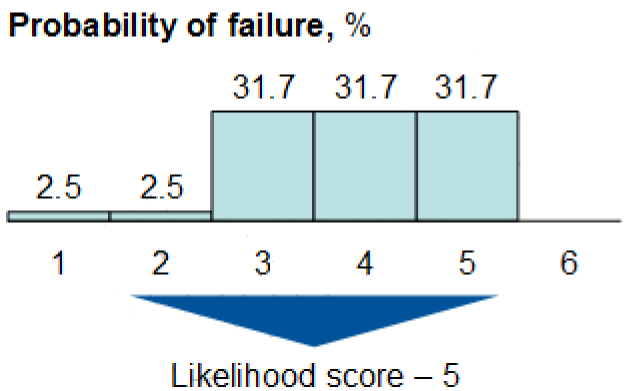
a. Please refer to Section 4 and Section 5 of the Company's LCIRP (https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-097/INITIAL%20FILING%20-%20PETITION/16-097_2016-01-15_GSEC_DBA_LIBERTY_LCIRP.PDF) for how the Company identifies potential risks. Please refer to the response to OCA 4-4 for information on systems that the utility uses to manage certain risks.

Refer to Attachment OCA 4-6 for the risk scoring matrix the Company utilizes for distribution investments. This matrix provides a relative risk ranking for investments and is used as a decision support tool in measuring and prioritizing risks. It is not a decision making tool.

Risks are evaluated and prioritized based on two criteria: (1) the impact or consequence of the risk, taking into account factors such as financial risk, the number and outage duration of customers impacted, load at risk, loading, voltage performance, and pocket frequency; and (2) the likelihood that such impacts will occur, ranging up to 1 in over 100 years. Once both the consequence and likelihood of occurrence of a risk are determined, the risk score is determined by scrolling across the table to where both scores intersect. It is possible that a system deficiency may have more than one risk. For example, a distribution feeder could be projected to exceed its normal loading rating in 5 years but could also be in current violation of the MWhr criteria. In this case, the highest risk is chosen.

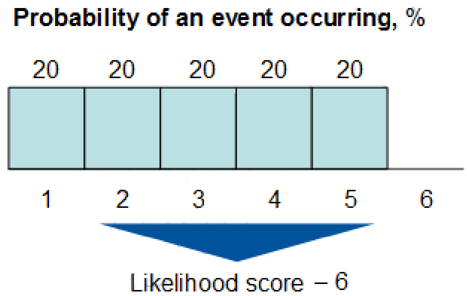
b. The probable incidence of each potential risk is estimated using the following approaches:

- Time to failure approach (results in likelihood scores after considering time to failure).
  - o The earliest and latest time to failure for an asset is established.
  - o The resulting likelihood score is derived by scrolling across the table. For example, if an asset is not expected to fail in the next two years, but is expected to fail in three to five years, the likelihood score is 5.



Time to failure (in years)	Likelihood level
<1 years	7
1 to 3 years	6
3 to 5 years	5
5 to 10 years	4
10 to 20 years	3
20 to 100 years	2
>100 years	1

- Time to certain event approach (results in likelihood scores after considering the time to a certain impact or the probability of an impact happening the following year (assuming uniform distribution)).
  - o The time to a certain impact or the probability of a certain impact happening the following year is established.
  - o The resulting likelihood score is derived by scrolling across the table. For example, if an event will happen in the next five years, such as a forecasted overload, (or the probability of the event happening the following year is 20%), the likelihood score is 6.



Years to certain impact	Likelihood level	Probability of certain impact happening next year
1	7	100%
2	7	50%
3	6	33%
5	6	20%
6	5	17%
10	5	10%
20	4	5%
100	4	1%
200	3	0.5%
500	2	0.2%
1000	2	0.1%
2000	1	0.05%

c. The consequence for each incident is estimated using the table provided in Attachment OCA 4-6. Consequences are of varying impact from Very Low to Very High are based on the magnitude of the identified deficiency needing to be addressed.

d. The levels of financial impact are provided in Attachment OCA 4-6, column labeled "$." Financial impact can be estimated for some risks. For example, financial impact to equipment failure can be determined from historical financial data from the replacement of similar equipment or from established investment grade estimates.

e. Please refer to Section 4 and Section 5 of the Company's LCIRP on how the Company employs risk identification and prioritization in distribution investment decisions.

   Each year, the Company develops an Annual Five-Year Investment Plan designed to achieve its overriding performance objective of providing safe, reliable service at reasonable cost to our customers. At the outset, the Investment Plan represents a compilation of proposed spending for programs and individual capital projects. Programs and projects are categorized by spending priority, i.e., Safety, Growth, Mandated, Regulatory Programs, and Discretionary. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects as well as initial estimates for newly proposed projects.

   All mandatory programs and projects known at this point are included in the plan. Examples of mandatory programs and projects include public requirements, which necessitate the relocation of our facilities, response to damage/failure and storms, and third party attachments. Once the mandatory budget level has been established, programs and projects in the other categories (i.e., growth, regulatory programs, and discretionary) are reviewed for inclusion in the investment plan.

   Plan inclusion/exclusion for any given project is based on several factors including, but not limited to: project new or in-progress status, risk/benefit, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed to optimize the total cost and outage planning. The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project.

The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. From an overall perspective, the Company’s objective is to arrive at a capital plan that is the optimal balance in terms of making the investments necessary to maintain and improve the performance of the system for customers, while also ensuring a cost-effective use of the Company’s available resources.

Risk Calculation Matrix

Impact / Consequence		Matrix Risk Score	$	Asset Replacement only CUSTOMERS SERVED	Impact Level	CI per event	CMI per event	MW at risk	MWh at risk	Normal Loading (%)	Voltage (pu)	Pocket Frequency
1	**Very Low**	1	≤5k	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
2	**Low**	2	>5-≤10k	100 < 500	Recl or Fuse Tap	≤500	≤30k	≤1.5	≤16	Not Used	Not Used	2
3	**Moderately Low**	3	>10-≤50k	500 < 1500	≤0.5 Feeder	>500≤1500	>30k≤90k	>1.5≤2.5	>16≤20	>75≤100	Not Used	3
4	**Moderate**	4	>50k-≤100k	1500 < 2000	>0.5≤1 Feeder	>1500≤2000	>90k≤120k	>2.5≤5	>20≤24	>100≤105	<0.95≥0.94	3-5
5	**Moderately High**	5	>100k-≤500k	2000 < 5000	>1≤3 Feeders	>2000≤5000	>120k≤300k	>5≤10	>24≤30	>105≤110	<0.94≥0.92	5-8
6	**High**	6	>500k-≤1M	5000 < 10000	>3≤5 Feeders	>5000≤10000	>300k≤600k	>10≤20	>30≤40	>110≤120	<0.92≥0.90	8-10
7	**Very High**	7	>1M	>10000	>5 Feeders	>10000	>600k	>20	>40	>120%	<0.90	>10
50	**Mandatory**											

Risk Score Matrix

Impact / Consequence		Risk Value							
Very High	**7**	**25**	**32**	**38**	**43**	**47**	**48**	**49**	
High	**6**	**20**	**29**	**33**	**40**	**44**	**45**	**46**	
Moderately High	**5**	**15**	**22**	**26**	**35**	**39**	**41**	**42**	
Moderate	**4**	**9**	**17**	**19**	**28**	**34**	**36**	**37**	
Moderately Low	**3**	**5**	**10**	**14**	**21**	**27**	**30**	**31**	
Low	**2**	**3**	**6**	**8**	**16**	**18**	**23**	**24**	
Very Low	**1**	**1**	**2**	**4**	**7**	**11**	**12**	**13**	
		1	**2**	**3**	**4**	**5**	**6**	**7**	**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**	

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 1

Date Request Received: 10/18/19
Request No. Staff TS 1-30

Date of Response: 11/1/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Response to Staff 6-23 (d). Does the contingency analysis for Spicket River also include any feeder ties with National Grid located on Liberty Street in Salem and Route 97 in Salem?

a. If the response is no, please provide any documentation from National Grid indicating that the feeder tie is not available for contingency situations.
b. Please provide the N-1 contingency analysis of the loss of the 23kV line to Spicket River utilizing 2019 loading data and indicate if the loading analysis includes National Grid as stated above.

RESPONSE:

a. Liberty's contingency analysis does not include ties with neighboring utilities as these are not guaranteed. The ties between National Grid and Spicket River are only with the 13L3 feeder and are used when outages are planned for maintenance needs. During the Quinn storm event in March 2018, these ties were not available as it was difficult to communicate with National Grid given their large service territory and other pending emergencies. These ties are located in National Grid's service territory and are not operated by Liberty personnel. There is no documentation provided by National Grid indicating that any feeder tie with Liberty Utilities is available at any given point as these are not guaranteed.
b. The loss of the 23 kV source for an outage on the 5.2 mile section would require the Spicket River circuits to be backed up by existing distribution circuit ties. Based on 2019 loading, the total Spicket River load is 24.2 MVA.

   The table below represents the available capacity on the 13.2 kV tie circuits as well as load at risk by circuit using 2019 actual loads, without considering the National Grid ties.

2019 Actual Loads				
Distribution Circuit	Ties	Available Capacity	Load at Risk (Amps)	Load at Risk (MVA)
13L1	13L2, 13L3	0	326	7.45
13L2	9L1, 9L3	279	11	0.25
13L3	10L2, 9L1, 18L2	261	182	4.16

Loss of the 23 kV sub-transmission supply circuit to the Spicket River No.13 Station would result in approximately 11.9 MVA of load at risk, after restorative switching occurs. This is an increase from 7.6 MVA of load at risk in 2016.

Liberty Utilities relies on the transmission provider to expedite repairs should an outage related problem occur anywhere along the 4.2 miles of transmission-owned 2376 sub-transmission line downstream of the 2376/2353 tie. This could cause Liberty Utilities to have up to 160 MWHrs of load at risk, after restorative switching has occurred, for an assumed repair time of 12 hours. This amount of load at risk violates Liberty's planning criteria.

The 9L1 has ties with both the 13L2 and the 13L3 feeder, which could pose difficulties in supporting both Spicket River feeders.

The former planning criteria by National Grid is not appropriate for a system the size of Liberty Utilities. According to the National Grid criteria, the transmission provider is required to return the failed sub-transmission line to service within 12 hours and is allowed 240 MWHrs of load at risk. A more conservative approach should be taken in this case because the 23 kV supply line feeding Spicket River Station is a sole source circuit without any contingency sub-transmission backup within Liberty Utilities' operating territory, and because of difficulties communicating with National Grid during emergencies as evidenced by Storm Quinn. The more conservative approach will eliminate reliance on the Transmission provider and allow Liberty Utilities to significantly reduce load at risk.

The table below represents the available capacity on the 13.2 kV tie circuits as well as load at risk by circuit using 2022 forecasted loads. This does not include ties with National Grid.

2022 Forecasted Loads (Extreme Weather Scenario)				
Distribution Circuit	Ties	Available Capacity	Load at Risk (Amps)	Load at Risk (MVA)
13L1	13L2, 13L3	0	379	8.66
13L2	9L1, 9L3	107	230	5.26
13L3	10L2, 9L1, 18L2	153	362	8.28

Loss of the 23 kV sub-transmission supply circuit to the Spicket River No.13 Station would result in approximately 22.2 MVA of load at risk, after restorative switching occurs. This could cause Liberty Utilities to have up to 269 MWHrs of load at risk, for an assumed repair time of 12 hours, after restorative switching has occurred. This violates Liberty's planning criteria.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 1

Date Request Received: 10/18/19
Request No. Staff TS 1-31

Date of Response: 11/1/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Response to Staff 6-23 (e).

a. Please provide the contingency analysis for the loss of the Goldenrock #1 transformer utilizing National Grid's capacity on the 23kV lines (2353 and 2376?) lines utilizing 2019 load data.

b. If the above analysis does not address the following questions, please provide the following:

   i. Does the "out of service" load stated in the response a post-switching load?
   ii. Does the load include future load that was not present in 2019 loading data?

c. Provide the size and type, normal, and emergency rating of the 23kV conductor from Goldenrock to Old Trolley riser structures on South Broadway.

d. The response also states that the 10MW and 240 MWhrs is above both Liberty and National Grid Planning criteria. Liberty Utilities LCIRP submitted in 2019 states a 60MWhr risk of load following post switching as a criterion. According to Attachment Staff 8-63.1, Bates Page 0034, in docket DE 16-383, National Grid Planning criteria in 2011 was 10MW and 240 MWhrs. Please provide the National Grid criteria that supports the above statement if different from the criteria provided in Staff 8-63.1 in docket 16-383.

e. In Liberty's 2019 LCIRP, Bates Page 0156, A substation N-1 contingency is stated as " If more than 60MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts and the cost to mitigate."

   i. Did the Company analyze the cost to mitigate in respect to the guideline of the risk being "evaluated and prioritized?" If so, please provide the documentation that illustrates that "evaluation and prioritization."
   ii. Did the Company weigh the contingency of loss of non-company asset (115kV-23kV National Grid transformer at Goldenrock) during a limited load period

where the load creates this contingency that ultimately results in an excludable reliability event in IEEE and PUC defined terms?

iii. Please provide the historical outage data for a loss of the #1 Transformer, if that is the equipment used in the analysis, at Goldenrock for 2009-2019.

f. Liberty states, "Simply replacing discrete pieces or groupings of equipment would not be feasible due to the multiple equipment deficiencies at the substations. Maintaining, repairing, or replacing the assets in their existing location and configuration, while possible, would be costly and would not be expected to yield a significant improvement in the overall reliability or operability of the substation. Due to the design and overall condition of the steel, foundations, bus, switches, and control houses, both substations would require significant rebuild in situ. Prior experience retrofitting vintage modular or box structure substations supports the notion that retrofit costs can quickly escalate."

   i. Does the Company have a detailed estimate and breakdown of a detailed replacement/refurbishment proposal for addressing the asset issues at Salem Depot and Barron Avenue by qualified substation vendors?

      1. If yes, please provide the documentation.
      2. If no, please explain why not?
      3. Are the vendors' estimates based on the Company's maintenance records and standards documents? If so, please indicate the applicable documents.
      4. Is the asset replacement/restoration estimate part of the 2017 Area Engineering study or business justification/project justification for the Rockingham substation and Goldenrock 13kV installation?

<u>RESPONSE:</u>

a. Under the contingency of losing the existing transformer at Golden Rock and using 2019 peak loads, the contingency load on the 2353 line would result in being loaded above its emergency rating by 5.1 MVA. The 2353 supply would likely trip at the source given this overload. Using 2019 peak loads, the contingency load on the 2376 line would result in being loaded under its emergency rating and would not trip. However, if the transfer schemes at the individual substations are not blocked, the resulting load transfers could result in the 2376 being loaded above its emergency rating and thus trip as well. Ultimately it is anticipated that the 5.1 MVA of load above emergency rating can be mitigated by transferring additional load to Spicket River and thus not result in a criteria violation.

   This 2019 contingency analysis for Golden Rock is skewed by the fact that Liberty extended the Pelham 14L4 feeder into the Town of Salem to allow transferring load from Golden Rock to Pelham. In 2019 these transfers started taking place, which resulted in approximately 300A or 6.9 MVA of Golden Rock load transferred to Pelham. Additional transfers from Golden Rock to Pelham are planned for 2020 to create additional capacity for Tuscan Village. The Company installed the 14L4 feeder to reduce the load at risk from Golden Rock and to provide temporary capacity for Tuscan Village until the Rockingham Substation can be built.

Under the contingency of losing the existing transformer at Golden Rock and using 2022 forecasted peak loads, the contingency load on the 2353 and 2376 lines would result in being loaded above their emergency rating by 15.7 MVA and 12.8 MVA respectively, even with the transfers to Pelham 14L4. Given the limited capacity in the area to transfer load to Pelham or Spicket River, the resulting MWhr at risk on the 2353 and 2376 lines could result in the range of 306 for each line.

There are several other criteria violations that would result for the 2022 forecasted year.

See Attachment Staff TS 1-31.a.xls for further details. This summary is provided using 2019 peak loads for the Salem planning study area and account for transfers to Pelham 14L4.

b. See the response to Staff TS 1-30.

   i. Yes
   ii. Results are provided for both 2019 actual loads and forecasted 2022 loads.

c. See Confidential Attachment Staff 1-3.b.(a).1.xls submitted in Docket No. DE 19-120.

d. Liberty is unaware of any planning criteria changes by National Grid since what was provided in Docket DE 16-383.

e. As follows:

   i. The Golden Rock load at risk was evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate. Using 2018 load data, in 2022 the risk score was categorized as 47, which is among the highest for Liberty. See Attachment Staff 1-3.b.(a).5.xls submitted in Docket No. DE 19-120, which contains a summary of identified deficiencies and risk scores forecasted for 2022 using 2018 load data. This summary was updated using 2019 load and provided in Attachment Staff TS 1-31.a.xls. Other projects related to the Company's responsibility to serve new customers in its service territory are categorized as 50 – Mandatory. Examples of this are blanket projects, public requirements, Golden Rock Substation, Golden Rock 19L8, Golden Rock 19L6, Golden Rock 23kV relocation, Rockingham Substation, Rockingham Substation Transmission Supply, and Rockingham Distribution feeders required to serve new customer growth.

   ii. A loss of supply from another utility or transmission outage does result in a PUC excludable event, however Liberty's customers are still impacted and the risk is major to Liberty Utilities. When reporting to the PUC, some year-end numbers provided annually are: No Exclusions, Excludes only PUC Major Events, Excludes only Loss of Supply by other Utility or Transmission Outage, and All Exclusions using PUC criteria. Please refer to the Company's annual reconciliation report for REP/VMP for detailed metrics reported to the PUC.

   A loss of supply from another utility or transmission outage is reported using IEEE criteria; thus, still posing a reliability impact and risk to Liberty. Typical values reported under the IEEE criteria are: SAIDI with MED, SAIFI with MED, CAIDI with MED, SAIDI without MED, SAIFI without MED, CAIDI without MED, SAIDI with MED minus LOS, SAIFI with MED minus LOS, and CAIDI with MED minus LOS. Please refer to US Energy Information Administration's annual survey.

iii. There are no reported instances of transformer failures at the Golden Rock substation.

f. As follows:

i. The Company does not have detailed estimates or breakdowns by qualified substation vendors. The Salem Area Study identified a risk where two Salem Depot Substation transformers would require replacement due to asset condition if the new Rockingham Substation were to be significantly delayed. Refer to Table 17 of the Salem Area Study. This replacement aims to mitigate asset condition at the Salem Depot substation and is not intended to provide capacity to supply the Tuscan loads.

1. Not applicable.
2. The 23kV system does not contain the necessary capacity to supply the future loads in the Salem Area. This, coupled with the existing asset condition issues at Salem Depot and Baron Ave, and the load at risk at Spicket River, prompted the Company to implement a strategy to move away from the 23kV system and into a more robust 115kV system. See the response to Staff 6-39 for further details on the Company's strategy to move to an 115kV based system.
3. Not applicable.
4. The asset condition of Salem Depot and Baron Ave substations and the load at risk that result from the area's projected loads are considered in the Salem Area Study.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 1

Date Request Received: 10/18/19
Request No. Staff TS 1-33

Date of Response: 11/14/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Responses to 6-24 and 6-36.

a. Please provide an updated development project similar to what is shown in 6-24 b.1 and b.2 with the buildings depicted on the drawing that have permanent electric service as of 8-31-19.
b. Please provide the narrative on the above buildings listed in 8a. above as it relates to the schedule legend on the drawings.
c. The loading on the park as depicted in 6-36 attachment (excel spreadsheet) does not align with the Company's earlier response of 2.094 MW, please explain the discrepancy.

RESPONSE:

a. Please reference Attachment TS 1-33.a. Please note the following comments regarding the attachment:
    - The buildings identified in Box 1 are located on the Southern Parcel. They are currently under construction with an expected Spring 2020 Completion Date.
    - The building identified in Box 2 is located on the Southern Parcel. This building is also under construction with an expected Fall 2020 Completion Date.
    - The building identified in Box 3 is located on the Southern Parcel. This building is also under construction with an expected Winter 2020 Completion Date.
    - The building identified in Box 4 is located on the North Parcel and is known as Salem Ford. This building was energized on 3/28/2018.
    - The buildings identified in Box 5 are located on the North Parcel and are known as the Dolben Property. There are five buildings located on this parcel. Each building was energized at different times in accordance with the Developer's Construction Schedule. Energization dates are as follows: 3/1/2018; 8/31/2018;

10/09/2018; 11/29/2018; and 1/25/2019. It should be noted that these buildings are not yet fully occupied with residents.

- The building identified in Box 6 is located on the North Parcel and consists of five Commercial Units. Two of these units are currently occupied while the remaining three are empty. The first commercial unit is occupied by Market Basket. Construction power for Market Basket was energized on 12/10/2018, but Market Basket did not open until 7/1/2019. The second unit is occupied by HomeSense. Construction power was energized on 5/20/2019, but HomeSense did not open until 7/1/2019.
- The buildings identified in Box 7 are located on the North Parcel and are known as Black Brook Properties. There are twelve buildings located on this parcel. Nine buildings have been constructed and three buildings are still under construction. There are various energization dates associated with this parcel between 5/22/2018 and 9/12/2019.
- The buildings identified in Box 8 have not yet been constructed. The Developer has not indicated when construction will begin.
- The buildings identified in Box 9 are not built. The Developer has indicated this portion of North Parcel is currently being redesigned.

b. Please see the response to part a.

c. The Company's earlier response of 2.094 MW was based on an estimate that relied on the anticipated annual kWh sales using industry load estimates. The Excel spreadsheet provided as Attachment Staff 6-36.xlsx gives actual load readings from two of the Company's pole mounted reclosers that supply the Tuscan development. Due to construction delays as a result of the developer's redesigning portions of the North parcel, the northern portion of the Tuscan development has yet to reach its maximum demand. The Company will continue to monitor this peak load.

TUSCAN VILLAGE

170 ACRE TUSCAN VILLAGE MASTERPLAN

PARKING (50 acres):	PROGRAM 50 Acres	SF.
1,700 Cars	*Retail*	160,700 sf
	Car Dealer	38,500 sf
	Multi-Family	256 units (260,000 sf) (+6,000 sf Clubhouse)
	Townhomes	96 units (300,000 sf)
	Total	**765,200 sf**

PARKING (120 acres):	PROGRAM 120 Acres	SF.
6,251 Cars	*Retail*	562,250 sf
	Tuscan Retail	12,000 sf
	Tuscan Hotel	+/- 160 rooms (134,000 sf)**
	Medical Office (Outparcel)	200,000 sf
	Office (Village)	100,000 sf
	Office (Outparcel)	475,000 sf
	Residential (Outparcel)	281 units (295,500 sf) 8,500 sf Amenity & Pool
	Residential (Village)	75 units (64,000 sf)
	Assisted Living	165 units (180,000 sf)
	55+ Duplex Development	30,000 sf
	Maintenance Garage	18,000 sf
	Total	**2,079,250 sf**

Hotel SF & Program Breakdown
Basement (mechanical): 12,500
Floor 1 (amenities, retail, banquet): 34,500 sf
Floors 2-4 (rooms) : 87,000 sf
Total SF: 134,000 sf

PRELLWITZ CHILINSKI ASSOCIATES

TUSCAN VILLAGE - MASTERPLAN
SALEM, NEW HAMPSHIRE
07/31/2018

3

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-064
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 2

Date Request Received: 10/22/19
Request No. Staff TS 2-9

Date of Response: 11/5/19
Respondent: Joel Rivera
Anthony Strabone
Heather M. Tebbetts

REQUEST:

Re: Staff 9-3; Project 8830-C42921 Install Splices – 6L2 & 6L4. Please provide the following information for this project:

a. An itemized breakout of burdens, AFUDC, and other costs leading to the variance of -$91,743.

b. Why was the original cost estimate set at $75,000 (Staff 9-3.2 at 27) and not $111,552?

c. Why was the potential for costs involving contractors, corrosion inside manholes, traffic control, pumping and cleaning manholes, not taken into consideration during the preliminary engineering and budgeting for this project?

d. Why was the Over Expenditure Form (See OCA Data Request 2-14.d.2 at 97) approved and signed in February 2018 instead of during the project year in 2017?

e. Work Orders/spreadsheets including #'s 8830-18002089, 8830-18002322, and 8830-18002089.

f. Please indicate if splices are a minor plant?

    1. If so, why is the labor costs capitalized?
    2. Please provide documentation that indicates the change from expense to capital and the associated company policy that is utilized for that determination.

RESPONSE:

a. Please see Attachment Staff 2-9.a.xlsx.

b. At the time of the estimate, this is what the Company projected the cost to be.

c. As noted during the technical session, the manholes were inspected prior to construction and found no issues. Once construction started, the manholes needed pumping and cleaning and thus the Company needed to complete this work prior to starting construction. Once the cables were moved during construction, corrosion was seen and needed to be remedied. Also, discussed at the tech session was the need for police detail when originally the town allowed for the use of flaggers during construction, but due to the location and the equipment encroaching on the road, police detail was later required by the town.

d. Over expenditure forms are completed on an annual basis and would be completed during the year and signed after the year ends.

e. Please see the response to part a.

f. When a splice extends the life of the cable, it can be capitalized. The Company relies on Attachment Staff TS 2-9.f.1 to provide guidance on this issue. The following Attachments are provided for this project:

- Attachment Staff TS 2-9.f.1: Plant Investment Procedure 613 for plant account 367.26.06 Disconnecting Device - URD/UCD – The reasoning behind this was replacement of the failing H disconnectable joints will extend the actual useful life of the 6L2/6L4 underground distribution system installed in 2010.
- Attachment Staff TS 2-9.f.2: Manhole records of the work completed.
- Attachment Staff TS 2-9.f.3: Drawing providing where the failing H joints were replaced.

NEW ENGLAND POWER SERVICE COMPANY
PLANT INVESTMENT PROCEDURE - 613
ELECTRIC PLANT UNITS

Account: UNDERGROUND CONDUCTORS AND DEVICES
DISTRIBUTION PLANT

367.01

NUMBER	TITLE	DESCRIPTION	UNIT MEASURE
367.24.01	CUTOUT	Oil Filled	Each
367.25.01	CUTOUT	Explusion Type	Each
367.26.01	OIL SWITCH		Each
367.26.03	SWITCH	Automatic Throwover Type	Each
367.26.04	SWITCH, DISCONNECT		Each
367.26.05	LOAD BREAK SWITCH OR VACUUM SWITCH		Each
367.26.06	DISCONNECTING DEVICE - URD/UCD ✓		Each
367.27.01	RELAY		Each
367.27.02	LINE FAULT INDICATOR, SUBMERSIBLE - URD		Each
367.27.03	LINE FAULT INDICATOR	(Consisting of: Control Cable, Sensors and Cabinet)	System
367.28.01	INSTRUMENT TRANSFORMER		Each
367.29.01	GROUND		Each
367.30.01	BUS SUPPORTING STRUCTURE		Each
367.31.01	ENCLOSED SWITCHING CENTER	Group 1, 0-1,000 C.F. - Include, Pad-mounted metal-clad Switchgear Assembly Units	Assembly
367.31.02	ENCLOSED SWITCHING CENTER	Group 2, 1001 - 2000 C.F.	Assembly
367.31.03	TRANSCLOSURE	For Housing Only	Each
367.32.01	FOUNDATION	Equipment	Each
367.33.01	TERMINAL JUNCTION BOX		Each
367.34.01	INSTRUMENT CABINET		Each

Date 5-23-83