Unitil Energy Systems

Report on
Least Cost Integrated Resource Planning
2016

Unitil
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1 EXECUTIVE SUMMARY

Unitil Energy Systems, Inc. (“UES”) hereby submits its 2016 Least Cost Integrated Resource Plan (“LCIRP”) pursuant to RSA 378:38.

UES, as a utility distributing electric power to the homes and businesses in the communities it serves, has a responsibility to plan, build and operate an electric distribution system to meet the present and future needs of its customers in a cost effective manner. UES, through its affiliate Unitil Service Corp. (“Unitil”), fulfills its planning obligation by performing various and ongoing assessments of the short-term and long-term requirements and capabilities of its system. These various assessments are integrated into a comprehensive, least-cost plan that ensures adequate and reliable electric service.

The planning efforts that are performed by Unitil include its own studies of UES distribution circuits, substations, and subtransmission facilities. They also include collaborative review with neighboring utilities and regional entities on planning activities for the external facilities that provide UES with access to the region’s transmission and generation resources. This report provides a description of these various planning processes, a forecast of future electrical demand for the UES service areas, the assessment of transmission and distribution requirements, and a listing of projects that represent UES’s least-cost integrated transmission and distribution plan.

Demand side planning is creating the need for change in the historical distribution and system planning processes. Customer acceptance of distributed generation technology coupled with expansion of existing energy efficiency and net metering initiatives is causing an increase in demand side resources. Historically the effect of these resources is generally included in the historical load data. The output of these distributed resources while measurable and known cannot fully be incorporated into future load forecasts due to intermittent and uncontrollable nature of the distributed resources being installed. In many cases, the output of the distributed resource does not align with the summer peaks. It is difficult at this point to determine the reliability and coincidence of these resources with the system peak. As more distributed resources are installed in the future, the diversity will begin to stabilize and increase the reliability of these units with respect to system planning.

2 OVERVIEW OF LCIRP

UES, through Unitil, performs various and ongoing planning activities to assess the short-term and long-term requirements and capabilities of its electric distribution system. These activities include distribution system planning to evaluate primary distribution circuits and substations, electric system planning to evaluate UES subtransmission facilities and system supply points, joint system planning to evaluate the external delivery system which provides UES access to regional transmission and generation resources, and participation in statewide and regional transmission planning efforts. In addition, UES’s LCIRP includes demand side resource planning.

The result of these activities is the development of a least-cost, integrated plan for the UES distribution system and the transmission and distribution systems that serve it. The following sections describe the various planning activities performed by Unitil. Attached to this report are appendices that provide planning studies, load forecasts, reliability planning, joint system planning and demand resource planning. This document including the attachments constitute Unitil's least-cost integrated transmission and distribution plan.

3 TERMINOLOGY

The following terms are used throughout the document.

System Supply – A collection of electrical facilities, including lines, transformers, and protection and control equipment that steps down electric power from the transmission system to the Subtransmission System. At this time UES does not own any System Supplies. All System Supplies to UES are owned by Eversource (i.e. Timber Swamp, Kingston, Great Bay, Garvins, and Oak Hill) . UES connects to the System Supplies at 34.5kV. The System Supplies of UES connect to the transmission system at 115kV and 345kV.

Subtransmission System – A collection of parallel 34.5kV lines, switching stations, and substations that are operated as redundant supplies that serve distribution substations. The system is designed such that for the loss of a subtransmission line, switching is performed to reconfigure the subtransmission system to serve the Distribution System from a different subtransmission line. The Subtransmission System may be operated radially or looped between multiple System Supplies. Unitil refers to Subtransmission System Planning as Electric System Planning.

Distributed Energy Resources – the various technologies including energy efficiency and local generation that can offset electricity supply imports and reduce effective demands on the Company's Distribution and Subtransmission System.

Distribution System – A collection of Distribution Lines, Distribution Substations, and isolation devices that directs the electric power from the Subtransmission System to the customers.

Distribution Substation – A collection of equipment and transformers used to step the subtransmission voltage (34.5kV) down to a lower voltage (13.8kV or 4kV).

Distribution Circuit – A radial feeder that serves customer load directly. A Distribution Circuit may originate from a Distribution Substation or a Subtransmission Line. The primary voltages of UES distribution circuits are 4kV, 13.8kV, or 34.5kV. Some Distribution Circuits include stepdown transformers that convert the primary voltage from 34.5kV or 13.8kV to 13.8kV or 4kV. A Distribution Circuit may include a normally open switch that would allow a tie to another Distribution Circuit during planned or emergency system switching.

Planning Criteria – A set of guidelines by which the Unitil electric system is designed and operated.

Peak Design Load – The forecasted load level at which there is a 90% probability that the load in a given year will be below this level. In any given year there is a 1-in-10 chance that the load will exceed this level. This load level is used with contingency analysis (N-1) in the planning process.

Extreme Peak Load - The forecasted load level at which there is a 96% probability that the load in a given year will be below this level. In any given year there is a 1-in-25 chance that the peak load will exceed this level. This load level is used to evaluate the system in its normal configuration (N-0) without any other contingencies. There is no acceptable load loss when using the Extreme Peak Load in the planning process.

4 SYSTEM DESCRIPTION

Unitil Energy Systems consists of two electric distribution systems – the UES–Capital system and the UES–Seacoast system. Both systems are geographically separate and operate independently of each other. The UES–Capital system serves customers in Concord, New Hampshire and surrounding towns. The UES–Seacoast system serves customers in the Seacoast region of New Hampshire.

UES does not own any generating facilities within either of its operating systems, nor does it own any transmission facilities. Therefore, UES is dependent on others to provide the physical access to the region's transmission and generation resources. UES receives Transmission Service from Eversource for connection to the region's transmission system. With the exception of one 115 kV /34.5 kV substation owned by UES, power is delivered to both the UES–Capital and the UES–Seacoast systems at the 34.5 kV distribution level at several locations via supplemental Distribution Service from Eversource.

4.1 UES–Capital System

The UES–Capital distribution system is comprised of 48 distribution circuits operating at primary voltages of 4.16, 13.8 and 34.5 kV. The majority of these circuits originate from 15 distribution substations supplied off the UES– Capital 34.5 kV subtransmission system, while 3 circuits and a few other single customer taps are supplied directly off 34.5 kV subtransmission lines.

The UES–Capital 34.5 kV subtransmission system is a collection of 7 lines, generally constructed in off-road rights-of-way ("ROW"). The subtransmission system is a subset of the UES distribution system, and is classified as distribution facilities. However, UES uses the term "subtransmission" to distinguish these portions of the system for their particular function of transporting power from the various supply points to traditional distribution substations and circuits. The Eversource supply into the UES–Capital system is delivered at Eversource's Garvins substation, and at UES's Penacook (from Eversource's Oak Hill substation) and Hollis substations (from Eversource's Garvins substation).

Eversource’s Garvins substation is located in Bow, NH, and is supplied off the 115 kV transmission system. It consists of a 115 kV high-side straight bus with three incoming line breakers, two 115 – 34.5 kV, 36/48/60/67.2 MVA transformers, and two 34.5 kV low-side bus halves with a total of six line breakers plus a breaker interconnecting to the adjacent Garvins Falls Hydro station. UES’s 374, 375 and 396 subtransmission lines take delivery directly at the substation from three of the 34.5 kV line breakers.

UES’s Hollis substation is located in Concord, NH. It takes delivery off the Eversource 318 subtransmission line, which is fed from a fourth line breaker at Garvins substation. That line runs north to supply Eversource distribution loads before tapping into Hollis substation.

UES’s Penacook substation is located in Concord (Penacook), NH. It takes delivery at two line breakers on its 34.5 kV bus from Eversource’s 317 and 3122 subtransmission lines. These two lines are supplied out of Eversource’s Oak Hill substation, also located in Concord, NH. Oak Hill substation is supplied off the 115 kV transmission system. It consists of two 115 – 34.5 kV, 24/32/40/44.8 MVA transformers, and two 34.5 kV low-side bus halves with a total of four line breakers plus a bus tie breaker.

There are several independently owned and operated non-utility generating facilities connected to the UES–Capital system.

4.2 UES–Seacoast System

The UES–Seacoast distribution system is comprised of 43 distribution circuits operating at primary voltages of 4.16, 13.8 and 34.5 kV. The majority of these circuits originate from 13 distribution substations supplied off the UES–Seacoast 34.5 kV subtransmission system, while 14 circuits and a few other single customer taps are supplied directly off 34.5 kV subtransmission lines.

The UES–Seacoast 34.5 kV subtransmission system is a collection of 18 lines, generally constructed in off-road rights-of-way (“ROW”). The subtransmission system is a subset of the UES distribution system, and is classified as distribution facilities. However, UES uses the term “subtransmission” to distinguish these portions of the system for their particular function of transporting power from the various supply points to traditional distribution substations and circuits. The UES subtransmission system is supplied at three system supply substations. Two of the supply substations are owned and operated by Eversource, and the third is a UES substation. The Eversource supply points into the UES–Seacoast subtransmission system is delivered at the Timber Swamp and Great Bay substations. The UES supply point is the Kingston Substation.

UES’s Kingston substation is located in Kingston, NH, and consists of two 115 – 34.5 kV, 36/60 MVA transformers and two 34.5 kV low-side buses with a normally open bus tie breaker. The transformers are supplied by two 115 kV radial transmission lines owned and operated by Eversource.

Eversource's Great Bay Substation is located in Stratham, NH, and consists of a 115 kV high-side bus, a single 115 – 34.5 kV, 24/32/40/44.8 MVA transformer, and a 34.5 kV low-side bus. UES's 3351 and 3362 subtransmission lines take delivery directly at the substation from two line breakers off the 34.5 kV bus.

Eversource's Timber Swamp substation is located in Hampton, NH, and consist of a 345 kV high-side ring bus, two 345 – 34.5 kV, 75/100/125/140 MVA transformers, and two 34.5 kV low-side buses with a normally open bus tie breaker. Each transformer separately supplies one of the low-side buses in the normal configuration. UES's 3160 and 3171 subtransmission lines take delivery directly at the substation from two line breakers off one of the 34.5 kV buses.

The UES-Seacoast system also has the ability to be served from alternate lines out of Timber Swamp substation and from Eversource's 3141X distribution line out of their Chester substation in certain planned or emergency situations.

5 SUBTRANSMISSION SYSTEM PLANNING

The Subtransmission System consists of parallel 34.5kV lines which serve Distribution Substations. The Subtransmission System is designed such that the loss of any one element (N-1 planning condition) will not result in the loss of load following restoration switching. Subtransmission System planning is conducted on an annual basis and covers a 10 year timeframe. Since the UES system is comprised of two geographically separate and distinct systems (Capital and Seacoast) separate planning studies are completed for each system. Unitil refers to Subtransmission System Planning as Electric System Planning.

5.1 System Planning Objectives and Methodology

The main objective of Unitil's electric system planning process is to provide safe, economical, and reliable service of the subtransmission system. Planning for expansion of the electric system is performed by Unitil's Distribution Engineering Department. The electric system planning process evaluates the UES subtransmission systems and the System Supply points serving the UES system. A flow chart displaying the full process of planning system improvement through budgeting approval is included in Appendix A of this report.

The study process examines a ten year forecast of system conditions to identify when individual equipment loading and voltage performance concerns will occur, and propose specific system modification recommendations to meet Unitil system planning guidelines (see Appendix B – Unitil Electric System Planning Guide). Recommended system improvements are based on safety, system adequacy, reliability and economy among available alternatives.

The electric system planning process starts with the Distribution Engineering Department forecasting the system load demands for the each UES operating area. Two load levels (Peak Design Load and Extreme Peak Load) are calculated and projected for ten years in the future. In projecting future loads, it is important to use realistically conservative load projections. If the load projections are not conservative enough, the system could be undersized for the amount of load experienced and electric equipment could fail resulting in large customer outages. However, if the load projections are overly conservative, the cost to the ratepayers to design and build a system capable of serving the projected load could be unrealistically high. For that reason Unitil uses two load levels in its system planning process. The Peak Design Load is used when evaluating the system ability during equipment contingencies. The Extreme Peak Load is the load level with a probability of being exceeded once every twenty-five years. This load level is used to evaluate the system capability during normal system conditions with no equipment contingencies.

The load projections are then entered into a computer model of the lines and electric system equipment. The model contains impedance and thermal ratings of the electric equipment to calculate the expected voltages and power flows at each point on the subtransmission system. These calculated power flows are used to ensure the voltage is within specific ranges and the equipment is not overloaded as described below.

5.2 System Load Projections

The scheduling of system modifications is dependent on the projected timetable of system loads that drive system capacity requirements. For planning purposes, system design load forecasts are developed using a linear trend regression model that correlates a ten-year history of daily peak load versus daily average temperature and humidity. This approach accounts for variations in projected peak loads due to year to year variations in temperature as well as other varying factors.

5.2.1 Projection Methodology

The historical basis for each system is a series of yearly regression models developed to correlate actual daily loads to a weighted temperature-humidity index (WTHI) derived from the average temperature and average dew point temperature of each day and the previous two days. Once a model is established, an estimated peak load can be derived for that season for any value of WTHI. There are two dimensions of variability introduced with this modeling. First is the highest WTHI experienced within a season, which varies with short-term weather trends from one year to another. Second is the model estimate of peak load at any specific WTHI. This estimate has its own variation of possibilities due to the influence of other existent factors not incorporated into the model. These variations are characterized as randomness in making future projections. The probability distribution for annual highest WTHI is assumed to follow the discrete distribution of past historical highest WTHI. The random possibilities of peak load outcomes for any specific WTHI are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that WTHI and varying based on its individual standard deviation according to the fit of the seasonal model to the actual historical values.

To establish load projections, a Monte Carlo simulation is run to produce random annual highest WTHI and random peak load estimates at those WTHI from each year's seasonal model that makes up the historical basis. Each trial in the simulation is projected forward using linear trending. This results in a range of peak load possibilities for each future year assuming linear growth, and varying due to annual highest WTHI possibilities and variability in loads versus WTHI. The likelihood of specific peak load levels occurring in any particular future year can be estimated from an assumed probability distribution using the mean and standard deviation of the trial results for that year. The Average Peak Load, Peak Design Load and Extreme Peak Load forecasts are set at specific probability limits per the intent of planning guidelines.

5.2.2 <u>Load Levels</u>

The *Average Peak Load* is provided as a guide for general load growth decisions not related to system infrastructure planning. The attached *Average Peak Design Load* forecasts are set at the 50% probability limit. Based on the assumptions of the modeling and projection methods, each year there is an equal likelihood of that year's peak demand load being either higher or lower than the *Average Peak Load* level.

For the purpose of assessing the adequacy of system infrastructure, contingency studies for the loss of major system elements are evaluated against *Peak Design Load* levels to identify where and when system constraints do not meet planning guidelines. The attached *Peak Design Load* projections are set at the 90% probability limit. This is intended to roughly equate to only a 1-in-10 year likelihood that the *Peak Design Load* level will be exceeded.

It is important to recognize that with this level of study, constraints and reinforcements are not necessarily associated with major contingencies occurring only at the highest peak hour of the year. Instead, they are associated with contingencies occurring any time during broader stretches of heavy loading that may or may not encompass that one maximum peak hour. In situations when actual demand somewhat exceeds contingency design forecasts, there should be less concern that design criteria will be challenged unless a contingency condition also exists at the same time. The probability of major contingencies existing at times when loads exceed *Peak Design Load* levels should be quite small. Furthermore, the period of exposure to those unplanned conditions should be kept brief if such an event were to occur.

More demanding *Extreme Peak Load* levels are used for evaluation of system constraints under these higher conceivable load conditions, but without the loss of major equipment. The attached *Extreme Peak Load* projections are set at the 96% probability limit. This is intended to roughly equate to only a 1-in-25 year likelihood that the *Extreme Peak Load* level will be exceeded. Under conditions up to these *Extreme Peak Load* levels, it is essential that the system, with all major elements in service, meet planning guidelines while serving all customers. In the event that conditions exceed these *Extreme Peak Load* levels, load shedding and/or additional loss of equipment life may be acceptable.

5.2.3 UES – Capital System Historical and Projected Loads

The peak load for the summer of 2015 of the UES-Capital system was 118.311 MW on July 30, 2015 at 2:00 PM. The 3-day weighted temperature index (WTHI) on this peak day was 19.0. The highest historical peak load for the UES-Capital system was 134.007 MW set on August 2, 2006 at 2:00 PM coinciding with the highest WTHI of 22.3 during the last ten years. The historical mean of annual highest WTHI values for the past ten years is 20.5. The linear trend of load normalized to the mean WTHI shows a decline of 0.42 MW per year with an average standard deviation of ±5.1 MW. Chart 1 below displays the historic and projected load for the past and future ten years. The Table 1 below lists the projected values of the Average Peak Load, Peak Design Load, and Extreme Peak Load for UES Capital for 2017 – 2026.

Chart 1. UES-Capital – Historical Summer System Peak Loads and Design Forecasts.

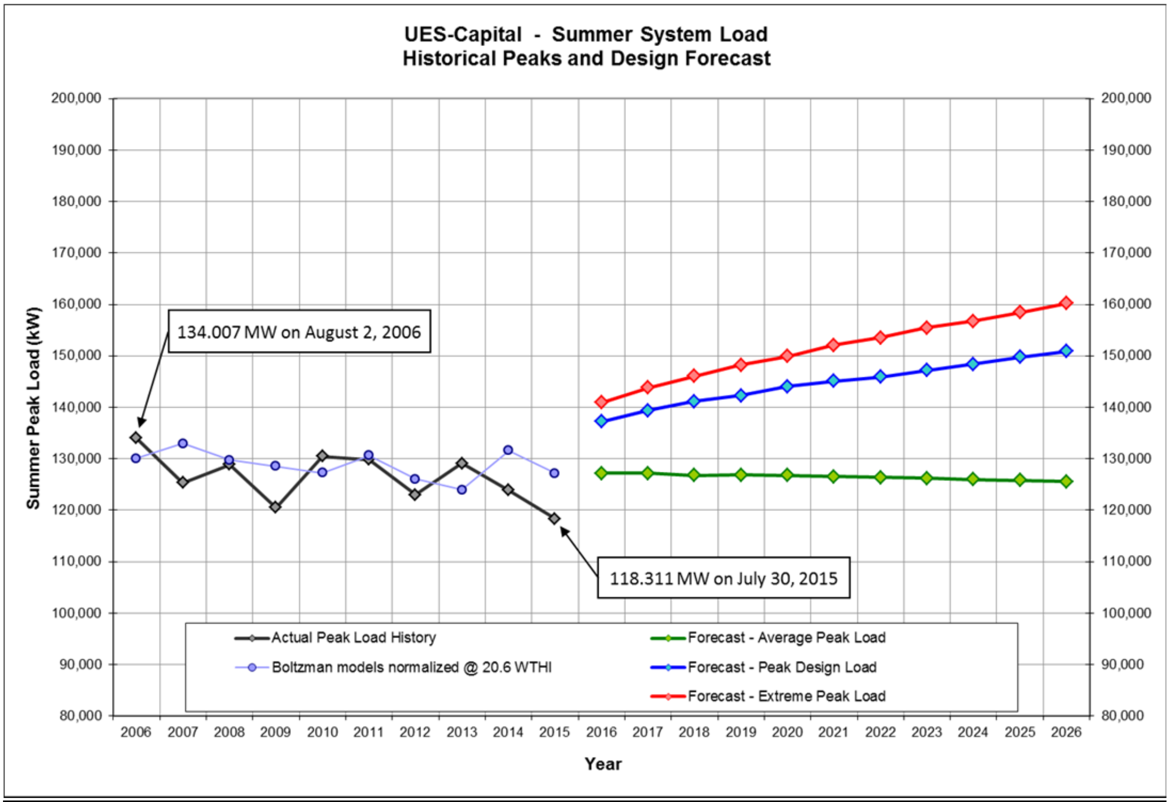


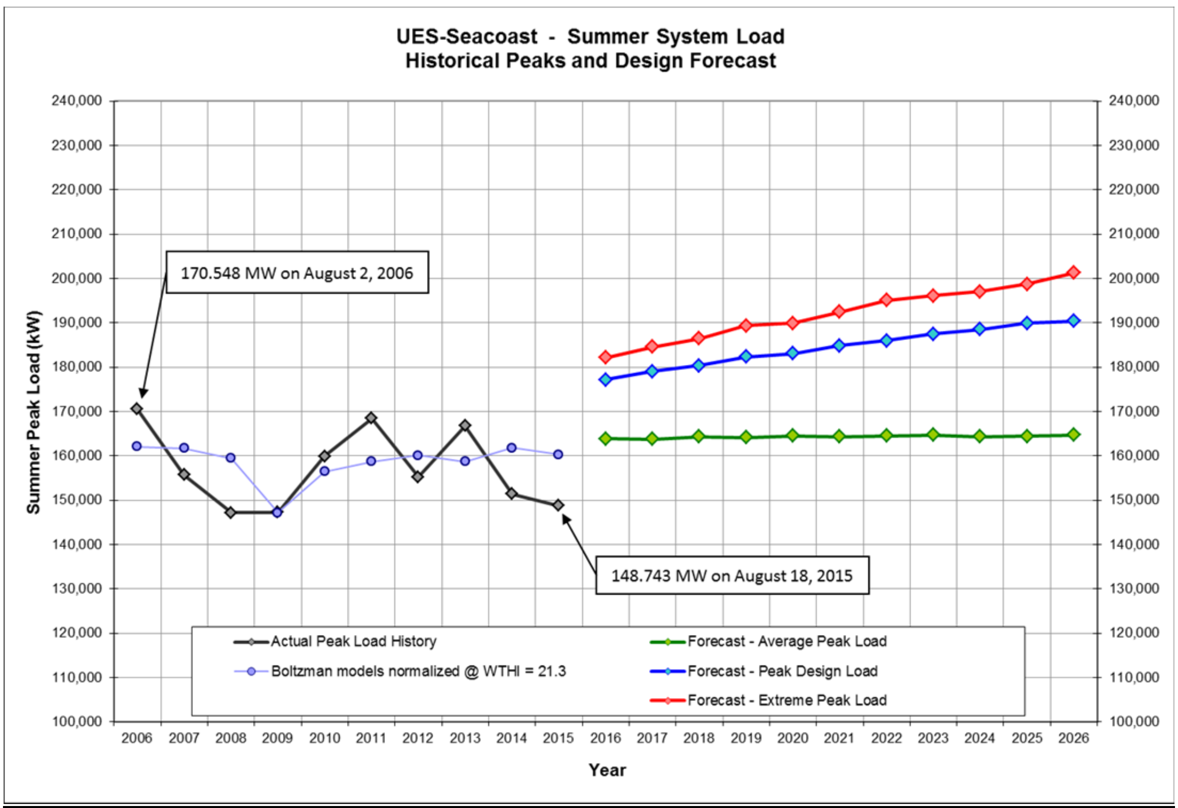
Table 1. UES-Capital Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2017	127.2	139.4	143.8
2018	126.8	141.1	146.1
2019	126.8	142.3	148.2
2020	126.8	144.1	149.9
2021	126.5	145.1	152.1
2022	126.4	145.9	153.5
2023	126.2	147.2	155.5
2024	126.0	148.4	156.7
2025	125.8	149.8	158.4
2026	125.6	150.9	160.2

5.2.4 UES – Seacoast System Historical and Projected Loads

The UES-Seacoast system reached a peak load for the summer of 2015 of 148.743 MW on August 18, 2015 at 4:00 PM. The 3-day weighted temperature index (WTHI) was 19.1 on this peak day. The highest historical peak load for the UES-Seacoast system was 170.548 MW set on August 2, 2006 at 5:00 PM coinciding with the third highest WTHI of 22.5 during the last ten years. The only days with a higher WTHI occurred during the summer of 2011 and 2013. Actual peak loads for these days were within 2.3% of the 2006 peak[1]. The historical mean of annual highest WTHI values for the past ten years is 21.3. The linear trend of load normalized to the mean WTHI shows an increase of 0.13 MW per year with an average standard deviation of ±7.3 MW. Chart 2 below displays the historic and projected load for the past and future ten years. The Table 2 below lists the projected values of the Average Peak Load, Peak Design Load, and Extreme Peak Load for UES Seacoast for 2017 – 2026.

Chart 2. UES-Seacoast – Historical Summer System Peak Loads and Design Forecasts



[1] - Peak loads and corresponding WTHI values for 2011 & 2013 were 168.5MW / 23.7 and 166.7 MW / 22.6 respectively.

Table 2. UES-Seacoast Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2017	163.8	179.0	184.6
2018	164.3	180.3	186.4
2019	164.1	182.4	189.4
2020	164.5	183.1	190.0
2021	164.3	184.8	192.5
2022	164.5	185.9	195.0
2023	164.7	187.4	196.1
2024	164.3	188.5	197.1
2025	164.5	189.9	198.8
2026	164.7	190.4	201.2

5.3 Element Ratings

Thermal ratings of each load-carrying element in the system are determined in order to obtain maximum use of the equipment. The same rating methodologies are used for subtransmission, substation and distribution equipment. The thermal ratings of each modeled system element reflect the most limiting series equipment within that element (including related station equipment such as buses, circuit breakers, and switches). Models will include three rating limits for each season's case; Normal, Long Term Emergency (LTE), and Short Term Emergency (STE).

5.4 System Modeling and Analysis

Traditional load flow analysis methods are used to evaluate the UES–Capital and UES–Seacoast systems for these studies. System modeling and power flow simulations are performed using Siemens PTI PSS/E power flow simulation software. Because summer hot weather conditions present the greatest thermal constraints on system equipment, and both UES–Capital and UES–Seacoast are historically summer peaking systems, these studies examined summer peak load conditions only.

An initial load flow model of each system is created to replicate actual conditions during their most recent past summer peak. Details of the system infrastructure are assembled using best available data on system impedances, transformer ratios, equipment ratings, etc. These models are added to a representation of the surrounding external power system in New Hampshire from load flow cases provided by Eversource, and the surrounding regional power system from a reduction of load flow cases developed by ISO-NE. UES–Capital and UES–Seacoast bus loads are compiled for the model by aggregating substation, circuit, and large customer load information for the summer peak timeframe. Much of this load information is available only as non-coincident, monthly peak demands. With the operating configuration, substation capacitors, and internal generation set in the model to actual conditions at the time, overall scaling adjustments are made to bus loads to reasonably match the power flow simulation results to actual recorded system flows for the peak day and hour. Once completed, this establishes confident models representing the UES–Capital and UES–Seacoast systems as they existed during their most recent actual summer peak hour.

Base case models for study of future years are developed from these historical peak models. System improvements and configuration changes that are anticipated to be completed during the year that the study is being performed are modeled, and known individual load adjustments are made. Then overall bus loads are grown by individual growth rates from separate distribution planning forecasts, and scaled to set the total UES–Capital or UES–Seacoast system load plus internal losses, as seen at the system supply delivery points, to the forecast loads for each year. Internal, non-utility generation is left set to their output levels at the time of the most recent actual summer peak.

These base cases are used to analyze normal operating conditions, extreme peak conditions, and all major design contingencies for each of the ten years under study. Unacceptable system conditions are identified as system deficiencies based on the Unitil Electric System Planning Guide (Appendix B). System improvement options are developed with assistance from the Energy Systems Engineering Department and the associated Electric Operations Department. A cost-benefit analysis is then performed on each option.

5.5 Recommendations

Recommendations resulting from the electric system planning process for the years of 2016 through 2025 are in included in Appendix C – UES–Capital 2016-2025 Electric System Planning Study, and Appendix D – UES-Seacoast 2016-2025 Electric System Planning Study.

6 DISTRIBUTION SYSTEM PLANNING

Distribution planning consists of radial circuit analysis planning on UES' 34.5 kV, 13.8 kV and 4 kV distribution circuits. Distribution planning also includes circuit load forecasting and loading reviews of UES' distribution substation transformers and equipment. Distribution system planning is conducted annually and covers a five year timeframe. Since the UES system is comprised of two geographically separate and distinct systems (Capital and Seacoast) separate planning studies are completed for each system.

6.1 Distribution Planning Objectives

The main objective of Unitil's distribution planning process is to provide safe, economical, and reliable service to our customers. System enhancements are planned with consideration for normal and reasonably foreseeable contingency situations, load levels, and generation in order to optimize existing distribution system capacity and optimize capital expenditures all while maintaining acceptable standards of service. The capability and reliability of the system is analyzed each year to identify planned investments required for the electric system.

6.2 Distribution Planning Process

The distribution system planning process evaluates distribution substations and distribution circuits based upon a five year load forecast to identify individual equipment loading and voltage performance concerns, and propose specific system modification recommendations. This process also updates a master plan for the development of a robust and efficient distribution system to accommodate long-term improvement and expansion throughout and beyond the study years. Recommendations are based on safety, system adequacy, reliability and economy among available alternatives. Unitil's Distribution Planning Guidelines can be referenced in Appendix E.

6.2.1 Circuit and Substation Load Projections

A five year history of summer and winter peak demands for each individual circuit is compiled from the monthly peak demand readings. A linear regression analysis is performed on the historical loads to forecast future peak demands for substation transformers, circuits and other major devices. Attempts are made to take into account known significant load additions or reductions, shifts in load between circuits, etc. In some instances, the peak loads do not present a confident trend over the historical period, so estimates are made using the best available information and knowledge of the circuit. In general, one standard deviation is added into these calculations to account for year to year variations in weather and other varying factors.

6.2.2 Substation Transformer and Circuit Position Loading

A detailed review is made of the limiting factors associated with the circuit positions and transformers at each substation. The limiting factors include current transformer (CT) ratings, protection device settings, switch ratings, circuit exit conductor ratings, regulator ratings, and transformer ratings. Overall Summer Normal and Winter Normal ratings for each circuit positions or substation transformers are based upon the most restrictive of these limiting elements.

Summer and winter peak load projections for the five year study period are compared to these ratings. Individual assessments are made where projected loads reach 90% of the Normal ratings for any circuit position or transformer. These individual assessments determine whether the loading condition requires remediation or simply further monitoring. Where remediation is recommended, specific options are outlined, including project descriptions, justification, predicted benefits and associated cost estimates. System enhancements and/or modifications are made prior to the load reaching 100% of the limiting element rating.

In addition to the magnitude of loading on the substation transformers and circuit positions, the balance of per-phase loading is reviewed. Recommendations are made to remedy per-phase loads measured or projected in excess of 20% imbalance.

6.2.3 Distribution Stepdown Transformer Loading

The loading of pole-top distribution stepdown transformers are also reviewed as part of the annual distribution system planning process. These units convert from one primary voltage level to another at certain locations on distribution circuits, and are of particular interest because they can often feed many customers similar to substation transformers.

Individual assessments are made where the existing or projected load on any unit reaches the transformer nameplate rating. Peak loading up to 120% of nameplate[2] (for summer ambient temperature conditions) is usually accepted if there is no expectation of future load exceeding this and no related voltage drop concerns.

6.3 Distribution Circuit Modeling and Analysis

Circuit modeling and analysis is performed on a three year rotating cycle for both the UES–Capital and the UES–Seacoast distribution systems, where each circuit is reviewed at least once every three years and more often if required. WindMil® (version 7.2) circuit analysis software by Milsoft Utility Solutions[3] is used for modeling and power flow simulation to identify potential problem areas.

Each circuit is modeled based on its present construction and normal configuration directly from Unitil's GIS system. This ensures the engineers are starting with the most up to date model available. Loads are then applied across the circuit using the five year load projections discussed above. Current or power magnitudes are compared to the seasonal rating criteria for each conductor section or piece of equipment detailed in the model. If the projected loading appears to exceed the seasonal Normal rating for any portion of the circuit, or the projected operating voltage is expected to fall outside of an acceptable range (97.5% to 105% of nominal for primary voltages), an individual assessment is made to determine how likely this condition may be and what follow-up actions are needed.

Where a concern in considered likely to exist, specific options are outlined, including project descriptions, justification, predicted benefits and associated cost estimates. In some cases, the condition may need field measurements or future monitoring to verify

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2 - Based on loading capabilities in Table 7 of ANSI/IEEE C57.91 for normal sacrifice of life expectancy for an 8 hour peak load duration with 30°C ambient temperature and equivalent loading exclusive of peak at 90% of nameplate.

3 - Milsoft Utility Solutions, Inc., 4400 Buffalo Gap Road, Suite 5150, Abilene, Texas 79606 (Tel. 800 344-5647)

whether or not a present or future concern truly exists. In other cases, a concern is considered likely based on the confidence in the data and knowledge of the situation.

6.4 Distribution Study Results

Recommendations resulting from the distribution system planning process for the 2016 through 2020 planning period are in included in Appendix F – UES–Capital Distribution System Planning Evaluation – 2016-2020, and Appendix G – UES–Seacoast Distribution Planning Study – 2016-2020.

7 JOINT SYSTEM PLANNING

Unitil participates in an annual joint system planning process with Eversource to establish an integrated, least cost plan of wholesale delivery facilities that affect both companies' systems.

7.1 Joint Planning Objectives

The goal of the Joint System Planning between UES and Eversource is to develop the most cost effective alternatives for the combined UES and Eversource system. Absent this process, UES and Eversource customers may be subject to more expensive system enhancements due to duplication of facilities between UES and Eversource. This process is intended to promote coordinated planning efforts between Unitil and Eversource to develop a single "best for all" plan that potentially affects both companies. The objective is to provide a consistent approach for the planning of safe, reliable, cost effective, and efficient expansion and enhancements to each other's local area systems while meeting regulatory and contractual requirements.

By agreement, this process establishes a Joint Planning Committee of Eversource and UES representatives. This committee meets several times on an annual schedule to bring all parties together to coordinate each company's individual plans. The committee considers the application of consistent planning criteria using agreed upon system data; the total cost of planned additions, including internal costs of each utility; the reliability impact of planned additions and modifications; operational considerations, system losses, and maintenance costs; technical considerations for standardized designs and equipment; and the intent of the wholesale supply contract.

7.2 Guidelines and Design Criteria

Each company uses its own guidelines and design criteria for their own individual planning. For joint planning, utility-specific criteria are applied for planning of Dedicated Use Facilities – those facilities which provide electric service to a single company. The design criteria of the affected system is applied for the planning of Dual Use Facilities – those facilities which provide both retail and wholesale service to more than one company. If there is a discrepancy between design criteria, the companies mutually agree on the solution.

Financial models for comparison of options employ a Net Present Value methodology, identifying capital expenditures on an annual basis. An annual return on equity shall be used in the Net Present Value calculations and is subject to review and agreement by each party annually.

System operating constraints and appropriate methods of evaluation are employed to determine preferred options. This includes but not be limited to: operation and maintenance costs, system losses, environment, reliability, and power quality. These criteria are mutually agreed upon.

Technical preference is often considered when evaluating alternatives. Technical preferences may include standard versus non-standard design. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of maintenance, ability to accommodate future expansion, or ability to implement. These criteria are mutually agreed upon.

7.3 Joint Recommendations

Joint recommendations are documented as a result of the Joint Planning Committee effort. These include recommendations for a 5 year construction plan and 10 year conceptual plan of *dual use* and *dedicated use* facilities, summary of potential planning issues and alternatives considered, discussion of unresolved issues, and summary of relevant changes from the previous year's recommendations.

Recommendations resulting from the joint planning process for the years of 2016 through 2025 are in included in Appendix H – UES-Eversource Joint Planning Recommendations 2016-2025.

8 TRANSMISSION PLANNING

Unitil evaluates the planning of the New Hampshire transmission system in several ways to ensure that it meets the short-term and long-term needs of the UES system and its customers. These facilities are external to the UES system and are owned and operated by others. However, they provide the UES system with access to the region's transmission and generation resources and Unitil's customers are affected by the ISO-NE transmission rates. Therefore, it is essential to Unitil's customers that the state's transmission system is built with the capacity and capability to supply UES system loads in a reliable and economical way.

8.1 Eversource Transmission Planning and NH Network Operating Committee

Unitil maintains a working relationship with the Transmission Planning department of Northeast Utilities in order to ensure that UES system needs are incorporated into Eversource transmission planning activities.

In addition, Unitil participates in an annual meeting of the New Hampshire Network Operating Committee. The NH Network Operating Committee is a group made up of representatives from Eversource and its transmission service customers in New Hampshire. These meetings establish a forum for Unitil to stay abreast of transmission planning activities in the state, and provide input concerning impacts to the UES system.

8.2 ISO-NE System Planning

Unitil also strives to keep informed on local and regional system planning issues independently from its relationship as a transmission customer of Eversource by regularly reviewing the activities of ISO-New England planning committees and working groups and contributing to these activities when it can.

Unitil regularly attends meetings of the ISO-NE Reliability Committee. This committee advises ISO-NE about design and oversight of reliability standards for the New England system, and about the development of the Regional System Plan, which UES also regularly reviews.

9 DISTRIBUTED GENERATION

UES does not own or operate any generating facilities and has no plans to install any at this time. The interconnection of Distributed Generation (DG) onto the UES electric system is administered by the Distribution Engineering Department using a detailed process which is consistent with other utilities in the states of New Hampshire and Massachusetts. DG includes independent power producers (wholesale contract of output power), and customer owned generation (behind a retail meter).

Customer owned DG consists of Net Metering facilities as well as generating units installed to assist with customer thermal loads or load reduction units. The number of small (less than 100 kVA) Net Metering units have increased noticeably over the past couple years. For planning purposes, these units become part of the historic load and are accounted for in load regression models.

Generators larger than 500 kVA are evaluated in the System Planning process when creating the base-case load flow models. In modeling the system, no more than one-half of large interconnected generation is considered as being in service for the study period. This is modeled by taking the most significant facilities out of service until the sum total of interconnected generation has been reduced by at least fifty percent (50%) from their typical historical output. Remaining units are modeled at their output coincident with the historical system peak. Hydro units are assumed not in service during the summer peak, due to low water levels during the summer.

10 RELIABILITY PLANNING

Unitil believes that reliability planning is just as important as traditional load flow or circuit analysis planning. Reliability planning is conducted by Operations and Engineering staff on an ongoing basis. Unitil implements projects and programs that 1) eliminate the outage from occurring or 2) minimize the impact of an outage by reducing the number of customers affected and the duration of time they are affected for. The various types of reliability planning are identified below.

Daily – Unitil Operations and Engineering personnel review every trouble report on a daily basis. This review focuses on system improvements that could be made in order to prevent that outage from reoccurring or ways to reduce the size or duration of the outage. Typically this review results in additional fusing locations or hot spot trimming activities.

Weekly – Until reports on overall company and individual operating center reliability performance compared to annual goals and past history. This review is used to track the current year reliability performance to benchmark it against company goals and historical performance.

Monthly – On a monthly basis, Unitil summarizes the largest outages that occurred in each of the operating companies over the past month. Unitil also reports on devices that have experienced multiple outages over a specific period of time and also reports on outages categorized by cause. The goal of this reporting is to identify trends and potential causes for the trends and initiate system improvements to address those trends.

System Event Report (SER) – Any outage that totals more and 300,000 customer minutes is required to have an SER report completed. An SER is a root cause analysis conducted by Operations and Engineering. The goal is to identify ways that the outage could either be avoided or the response shortened in the future. Typically an SER recommends action items that are assigned and completed.

Annual – Unitil conducts reliability analysis on an annual basis that is focused upon the overall reliability performance of the UES systems for an 18 month period. The report evaluates individual circuit reliability performance over the same time period. The report uses a combination of the Trouble Reporting System and GIS to spatially represent outages. The spatial representation allows Unitil to focus on areas of the system that has experienced below average reliability. Reliability improvement projects are designed and estimated. Reference Appendix I – UES-Capital Reliability Study 2015 and Appendix J – UES-Seacoast Reliability Study 2015 for the most recent annual reliability reports.

Each of the projects is compared based upon a cost per saved customer minute and saved customer interruption basis. These projects are submitted for capital budget consideration. The report also analyzes:

- Analysis of the ten worst outages that occurred over the timeframe along with their associated impact to UES-Seacoast system SAIDI and SAIFI

- Analysis of the effect of sub-transmission outages on circuit performance.

- Analysis of the worst performing distribution circuits over the reporting period

- Analysis of the major causes of sustained interruptions.

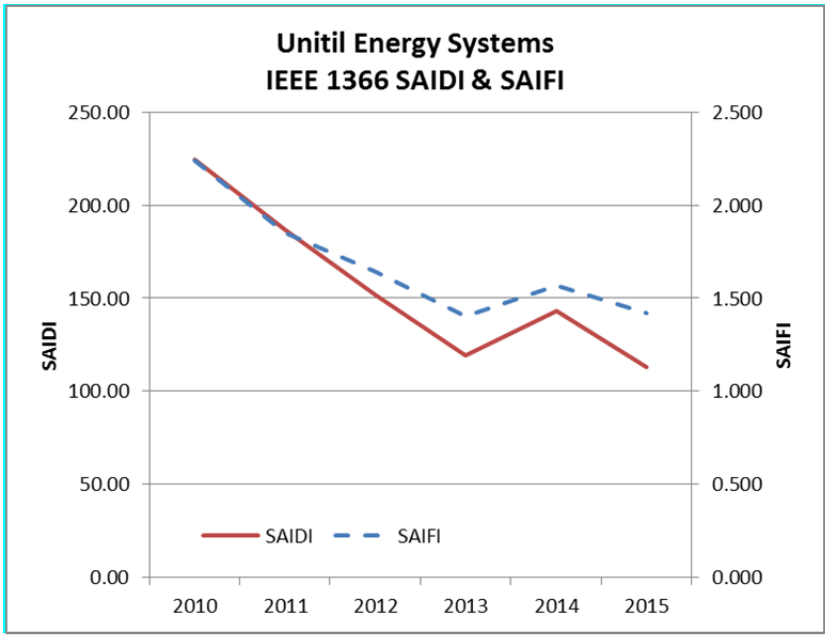
- Analysis of the performance issues on specific circuits as well as recommendations for improvement

- Analysis of equipment failures to identify trends and provide recommendations when necessary.

- Analysis of areas with multiple tree related outages for consideration for additional tree trimming.

The reliability planning process that Unitil uses has proven very successful. The historical reliability performance for the UES system for the time period from 2010-2015 is outlined below. Chart 3, below, displays annual SAIDI and SAIFI for the combined UES systems. The reported reliability performance of the UES systems in 2015 (based on IEEE-1366) was the best performance in the last five years in terms of SAIDI and the number of interruption events experienced. The combined UES system SAIDI of 112.73 minutes is roughly 26% lower than the 5 year average of 152.89 minutes. The UES combined system SAIFI for 2015 was 1.421 interruptions which was the best performance in the last five years. The system SAIFI was approximately 12% lower than the 5 year average of 1.623.

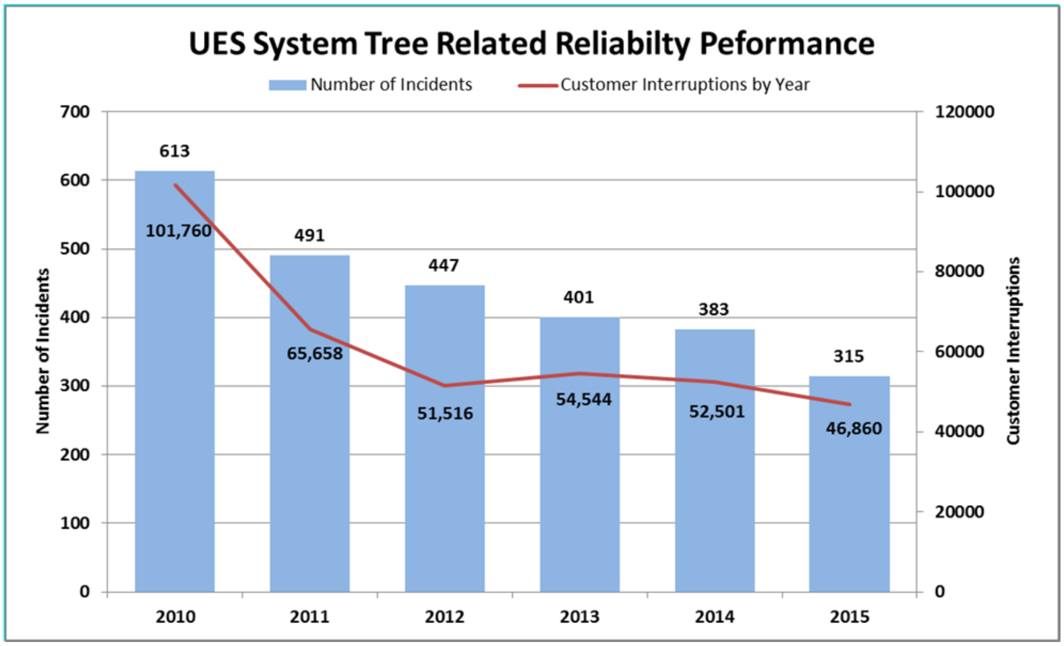
Chart 3: UES Annual Reliability



As the Vegetation Management Program progresses through its first five year prune and hazard tree cycles, the effects of these programs on reliability have begun to emerge. Overall New Hampshire system tree related reliability performance was reviewed. The chart below, displays the number of tree related incidents per year as well as the number of customers interrupted from tree related incidents from 2010 to 2015. The data used for this comparison excludes all major storm events identified by the NH PUC definition of a major storm in effect prior to 2015. The data for 2015 uses IEEE 1366 methodology for identifying major event days. However there were no major event days during 2015 that excluded tree related interruptions.

Chart 4 shows a steady declining trend in tree related incidents as well as in customers interrupted from 2010 through 2015. The number of tree related incidents and the number of customers interrupted were at their lowest point in 2015 over this five year period. The number of interruptions was below the five year average for the third year in a row while the number of customer interruptions was below the five year average for two years. These results clearly indicate that the VM program is producing positive results.

Chart 4: UES Tree Related Outages



11 Smart Grid

In addition to Unitil's detailed approach to reliability planning, Unitil has been implementing Smart Grid technologies for many years. Each of these smart grid technologies are tools the Company uses to improve reliability.

11.1 Smart Grid Technology

Unitil's Advanced Metering Infrastructure (AMI) system is capable of 2-way communication between the Command Center and the meter. In addition to the required metering information, the AMI endpoint can bring back outage information as well as endpoint health information. The AMI system is integrated with the OMS system to provide outage information down to the individual customer meter. Unitil's centralized dispatch function uses the information from AMI to verify the size of outages as well as identify imbedded outages that might not have been identified in the field.

Unitil's Geospatial Information System (GIS) allows spatial data management with analysis capabilities. GIS supports numerous corporate business applications at Unitil including: 1) outage management, 2) Design management used in preparing construction work sketches, work flow management and exporting Compatible Units (CU's) to Operations Data Integration (ODI) to generate job cost estimates; 3) Network and asset management for the management and configuration of all Unitil electric circuits; 3) Distribution mapping, querying, and reporting, and 4) System integration with external databases (CIS and AMI, CMS, and TIR) for Visualization and Analysis.

Unitil has implemented an integrated voice recognition system which provides outage information automatically into the OMS system. The IVR system also serves as the means that the OMS system uses to provide outbound calls to customers and provide them with updates about their outage.

Unitil's Outage Management System (OMS) provides a single automated and authoritative status of customer electrical outages across all Unitil electric operating companies. Outage reports are sent internally to Central Electric Dispatch (CED), Communications, customer service, emergency operations centers, operations engineering, and senior management. External reports are sent to regulators, media (via communications team), municipal and elected officials, and customers. There are four principal software applications in the ABB systems: 1) ABB Network Manager DMS which includes the outage reporting map, providing a visual display of power distribution systems, and operations management interface, which allows operators to view data and update data in various ways. 2) Siena Tech Suite of Reporting and Management Tools providing trouble call entry, reporting calls, outage dashboard, and Siena Support in a web presentation format. 3) Siena Tech Custom Unitil Reports offering Unitil-specific, read-only reports for daily reporting and regulatory requirements. 4) Siena Tech Hosted Outage Web Map providing a hosted web page presenting public-facing near real-time outage information.

Unitil implemented supervisory control and data acquisition (SCADA) at most of its distribution substations as well as some recloser and switch locations out on its distribution system. In addition, field RTUs and similar RTU-like devices are deployed at locations where distribution circuits originate directly off the sub-transmission lines.

Unitil has begun implementing distribution automation which consist of just a few recloser installations that either perform their own independent decision-making for automatic sectionalizing (i.e. opening not associated with fault protection tripping) and/or automatic transfer schemes between adjacent reclosers. The automatic transfer schemes do involve interconnection between two intelligent devices, but each of these that presently exist involve side-by-side devices with discrete hardwiring between them, copper or fiber optic data cabling, or in one case unlicensed 900 MHz radio (in close proximity to each other and line-of-sight).

11.2 Unitil's Vision of Grid Modernization

Unitil began a process in 2014 to develop a Grid Modernization Plan (GMP) for its Massachusetts subsidiary Fitchburg Gas and Electric Light Company (FG&E) in response to the Massachusetts Department of Public Utilities docket 12-76.[4] The GMP was developed specifically for FG&E but throughout the process, Unitil was focused on

[4] The proposed Grid Modernization plan for Fitchburg Gas and Electric Light Company was filed on August 19, 2015 pursuant to the MA DPU Orders in Modernization of the Electric Grid, DPU 12-76-B (2014) and 12-76-C (2014) and has docketed DPU 15-121. The plan has been included as Appendix K to this filing.

identifying projects and programs which could readily be applied in New Hampshire due to the similarities of the distribution systems.

Conceptual projects were detailed and organized in a manner that allowed the Company to convert a roster of projects into a set of projects that received further review and analysis. Consistent with the emphasis on practical grid modernization evaluation, the Company also considered the relative size of each investment, time to implement, perceived level of risk, and rate impact. Projects were repeatedly discussed; costs and benefits reexamined, and were considered in the context of their alignment to identified objectives.

The chart below identifies the projects that the Company identified through the project development process. The projects in blue are those projects that the Company has determined may have a positive benefit on the Company and our customers. Projects in grey have been determined to be of lower priority at the current time and may be re-evaluated in the future.

DER Enablement	Reliability	Distribution Automation	Customer Empowerment	Workforce & Asset Management
• A.1 Tariff for customer owned DG • A.2 Circuit capacity study • A.3 Website for prequalifying DG • A.4 DG monitoring and control pilot • A.5 DER analytics and visualization platform • A.6 3V0 protection at substations • A.7 Substation Voltage Regulation Controls • A.8 DER Monitoring (RD&D) • AL.1 Energy Storage-Battery Farm	• B.1 Reduce the SRP cycle to 5 years • B.2 Enhance hazard tree program • B.3 #6 Copper replacement • B.4 Install jacketed tree wire or spacer cable • B.5 Breakaway service connector • B.6. BI dashboard • B.7 Improved ETR tool • B.8 Integrate Enterprise mobile damage assessment tool • B.9 Integrate AMS with OMS • B.10 OMS Resiliency – Hot Standby • BL.1 Proactive pole inspection • BL.2 Class B Dist. Stds • BL.3 Pole loading study • BL.4 Replace UG cable • BL.5 Undergrounding • BL.6 Probabilistic Outage prediction • BL.7 Crew Callout System • BL.8 Planned Outage Tool	• C.1 Auto 69 kV substation switches • C.2 Auto cap banks for VVO • C.3 Auto voltage for VVO • C.4 Auto LTCs for VVO • C.5 SCADA comms to FGE substations • C.6 Field Area Network for DA • C.7 ADMS • C.8 Auto sectionalizing and restoration • C.9 Energy efficiency tariff • CL.1 SCADA fault indicators - FLISR • CL.2 Automated reclosers – FLISR • CL.3 FLISR ADMS module	• D.1 Energy information web portal • D.2 Customer mobile app • D.3 Gamification pilot • D.4 Customer education program • D.5 Pre-payment • D.6 TVR AMS • D.7 Behind meter interface std • DL.1 Control of appliances	• E.1 Mobility platform for field work • E.2 AVL for foreign crews • E.3 WOMS • E.4 Condition based maintenance program • E.5 BI dashboard for asset health and performance

As the Company considered the competing interests that influence the selection of projects, it became obvious there were some high level areas of capability and enabling technology that warranted thorough analysis. The provisioning of AMF and TVR, DER integration and leveraging voltage optimization technologies were all important aspects of grid modernization, while expanding field communications is a foundational capability of a modernized grid.

Subsequent to the grid modernization analysis, the company continues to evaluate additional smart grid technologies. The Company is currently in the early stages of investigating the possibility of residential sized and utility sized energy storage technologies. These technologies would help to provide a means for enabling further DER integration in areas that may become DER capacity constrained as well as provide a higher efficiency and availability of intermittent, renewable resources that could provide improved benefits to the electric system.

12 DEMAND SIDE ENERGY MANAGEMENT PROGRAMS

Since 2002 electric and natural gas utilities in New Hampshire have managed and administered the statewide CORE Energy Efficiency Programs, also known as NHSaves. From 2002 through 2014, UES's electric customers have saved over 1.1 billion electric kilowatt-hours over the life of the energy efficiency measures installed. This translates into customer savings of nearly $190 million. UES offers efficiency programs designed to meet various customer needs.

Benefits to UES customers include:

- Education and support for new home buying customers to build highly efficient homes that use 15-20% less energy than a standard new home.
- Incentives for insulation, air-sealing and other weatherization work in residential homes, performed by qualified private contractors and reducing a homeowner's heating costs by more than 15%.
- No cost insulation, air-sealing and other weatherization work performed for income qualified customers, saving them approximately $350 annually in energy costs. This program is offered in collaboration with the NH Office of Energy and Planning's Weatherization Assistance Program and the Community Action Agencies around the state.
- Our residential appliance programs work with over 100 retailers throughout the territory to help customers purchase highly efficient appliances that use 10-20% less energy than standard models.
- Our lighting program encourages customers to purchase energy efficient light bulbs that use a fraction of the energy of standard bulbs, while lasting 10 times longer.
- Our business programs help businesses and non-profits identify and install more efficient lighting, controls, motors, HVAC equipment, air compressors and industrial process equipment. These measures save customers energy and reduce their energy costs, resulting in more money to invest in their operations.
- Incentives to schools and municipalities save energy in public buildings and reduce the burden on taxpayers.
- An easily accessible NHSaves.com website that provides information to customers about efficiency programs as well as general information about how to save energy at home, at work, and in your town.

Through an innovative management approach and in collaboration with the other utilities, UES's programs have evolved over time. This is in response to the availability of new energy efficient technologies, changing market conditions, evaluation and monitoring studies, and new codes and standards. One new innovative approach is offering residential customers private financing through local lending institutions in which the Company buys down a portion of the interest. This leveraging allows for more capital to be available than previous loan products would allow.

12.1 Impact of UES's programs on Energy Consumption

Table 3 below summarizes UES's actual expenditures, lifetime kilowatt-hour savings, annual kilowatt-hour savings and customer participation during the 2014 program year by customer sector and program. Based on the 2014 results, UES saved kilowatt-hours at an average cost of $3.26 cents[5] per lifetime kilowatt-hour as compared to the current average retail price per kilowatt-hour of 16.17 cents.[6]

Table 3: UES 2014 Energy Efficiency Program Results

	UES Expenditures	Annual kWh Savings	Lifetime kWh Savings	Customer Participation
Residential Programs				
ENERGY STAR Homes	$ 121,657	78,471	1,780,964	18
Home Performance with Energy Star	$ 285,443	42,802	861,242	77
ENERGY STAR Lighting	$ 217,964	646,394	9,156,554	(1) 32,190
ENERGY STAR Appliances	$ 276,294	440,483	4,630,494	2,682
Home Energy Assistance	$ 484,356	59,868	932,408	59
Res K-12 Education & Code Training	$ 14,550	-	-	-
ISO-Related Expenses	$ 9,700	-	-	-
Subtotal Residential	$ 1,409,966	1,268,019	17,361,661	35,026
Commercial/Industrial Programs				
Large C&I Business	$ 714,621	3,077,516	43,289,566	13
Small C&I Business	$ 505,018	1,611,760	21,279,278	89
Municipals	$ 121,364	190,328	2,762,718	8
C&I Education, Codes & Audits	$ 4,195	-	-	-
ISO-Related Expenses	$ 4,693	-	-	-
Subtotal C&I	$ 1,349,892	4,879,604	67,331,562	110
Total	$ 2,759,858	6,147,623	84,693,224	35,136

(1) Number of products rebated.

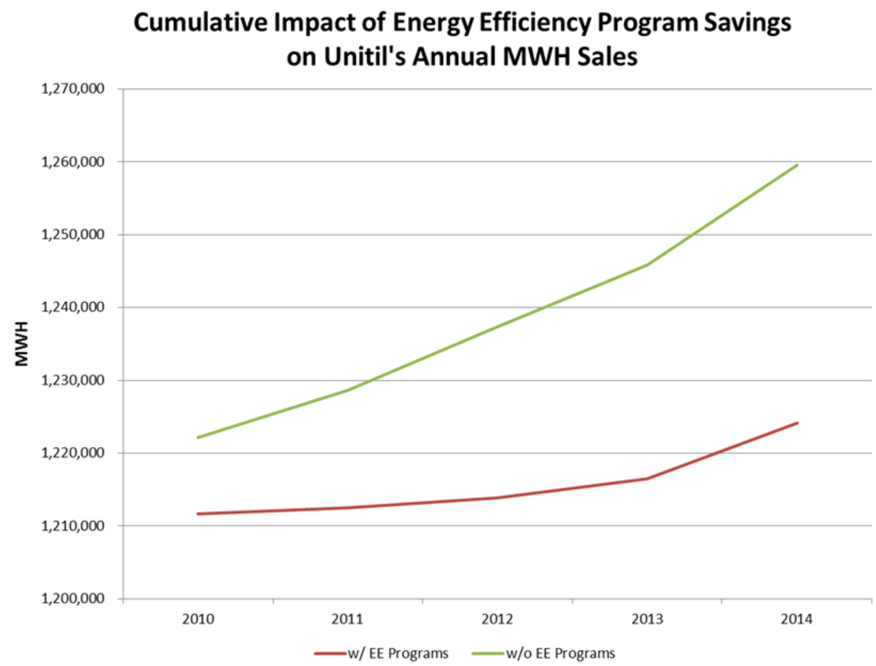
The 2014 annual kilowatt-hour savings are approximately 0.5% of UES's total billed delivery kilowatt-hour sales in 2014 (6,147,623 Annual kWh Saved ÷ 1,225,254,450

[5] This calculation does not include performance incentive. UES's cost per lifetime kWh of 3.26¢ was derived as the Company's 2014 EE expenditures of $2.76M divided by its 2014 lifetime savings of 84.7M kWh times 100.

[6] New Hampshire Office of Energy and Planning average electricity price March 22, 2016

Billed kWh). The average life of the installed energy efficiency measures is 13.8 years. As a result, the savings associated with the measures installed in 2014 will continue well into the future. As illustrated in the chart below, the impact of the Company's EE Programs over the past five years has resulted in a cumulative decline of delivered sales of 35,419 MWh in 2014.

Chart 5: Energy Efficiency Impact



Impact of UES's programs on Capacity or Peak Reduction

In addition to the kilowatt-hour energy savings, UES's Programs also provide capacity or peak demand reductions. Table 4, below, summarizes the average annual capacity reduction coincident with the New England peak resulting from operable efficiency measures installed by customers between January 2006 and December 2014. As shown, the programs implemented by UES reduce New England's peak load, which currently occurs in the summer, by 1.2 MWs, which is approximately 0.44% of UES's 2014 summer peak load[7] in New Hampshire (1.2 / 275.0).

[7] Unitil Energy System Inc.'s summer peak occurred on July 2, 2014, hour ending 1500, coincident with ISO-NE's 2014 summer peak.

Table 4: Energy Efficiency Programs Capacity Reduction based on Operable Measures installed Between Jan-06 and Dec-14

	Coincident with ISO-NE Peak	
	Summer kW	Winter kW
Residential		
ENERGY STAR Homes	333	568
Home Performance w/ ENERGY STAR	76	189
ENERGY STAR Lighting	1,564	3,334
ENERGY STAR Appliance	552	470
Low Income		
Low Income Home Energy Assistance	54	94
Commercial & Industrial		
C&I Lost Opportunity	1,320	1,040
Large C&I Business	4,604	3,891
Small C&I Business	2,056	1,887
Municipalities	45	71
Grand Total		
	10,605	11,542
Average kW / Mo (108 Months)	98	107
Annualized Capacity Reduction	1,178	1,282

The four New Hampshire electric utilities, including UES, are the only energy efficiency providers in New Hampshire participating in ISO-NE's forward capacity market. The cumulative proceeds obtained through participation in this market have totaled $1.3 million from 2007 through 2014 for UES customers. These proceeds are utilized as a funding source for efficiency programs, and represent approximately 9% of UES's 2015 electric programs budget. In order to qualify for payments from ISO-NE, UES must certify to ISO-NE's satisfaction that the capacity reductions are operational during hours of peak electrical usage.

UES has developed the necessary reporting and measurement and verification plans needed to evaluate the impact of the efficiency measures at the time of the New England peak and the resulting capacity reduction load value that qualifies for payment from ISO-NE. UES has met the rigorous reporting standards and requirements to participate in the forward capacity market. As a result, the estimated capacity reductions summarized above are an accurate representation of the capacity reductions resulting from the efficiency programs as they have been thoroughly reviewed by ISO-NE and independently certified.

12.2 Energy Efficiency Measures and Initiatives Recently Implemented to Reduce Energy and Capacity

Market Assessment Study of Air Conditioning Equipment:

An evaluation study undertaken by the Cadmus Group in 2013 reviewed the impact of air conditioning equipment in the residential and commercial/industrial sectors on peak load. The final report entitled "New Hampshire HVAC Load and Savings Research" studied the drivers of the increasing air conditioning load in both the residential and Commercial/Industrial sectors recommended additional measures to reduce peak load, and provided estimates of the ancillary electric savings associated with weatherization in the Home Performance with ENERGY STAR Program. As a result, UES captures the impact of ancillary electric energy savings associated with boiler circulator pump savings, furnace fan savings, furnace with new ECM motor savings, central AC savings, and room AC savings in its whole house weatherization programs.

UES also added or expanded incentives within its residential and commercial programs for high efficiency ENERGY STAR central air conditioning and air source heat pumps, as well as high efficiency ductless mini-split heat pump systems, which provide heating and air conditioning more efficiently than traditional air conditioning or fossil fuel heating.

Lighting Incentives Now Focus on LEDs

Along with the other utilities, UES has transitioned to primarily incenting LEDs lighting (rather than compact fluorescents) in both the residential and commercial/industrial sectors. The energy savings associated with LEDs is higher than CFLs, and the life expectancy of LEDs is longer. Market transformation of the lighting market is rapidly changing, and baselines will be increasing as CFLs exit the market, EnergyStar standards evolve and DOE's EISA standards take effect over the next several years.

Targeting Electric Space Heating Customers

UES gives priority to customers who heat their homes with electricity in the Home Performance with ENERGY STAR and Home Energy Assistance programs. The average annual kilowatt-hour savings associated with electrically heated homes is approximately four times higher than the average annual kilowatt-hour savings associated with non-electrically heated homes.

12.3 UES's Programs as a Demand-Side Resource

UES programs saved approximately 85 million lifetime kilowatt-hours in 2014 at a total cost of $2.8 million and the operable energy efficiency measures installed between January 2006 and December 2014 reduced New England's peak load by more than 1.0 MW. The average life of the energy efficiency measures installed in 2014 is 13.8 years, which means the cumulative energy savings of the Program increases as more energy efficiency measures are installed. As shown in Table 5 below, the forecasted UES load growth percentage would be approximately 43% higher ((1.43%%/1.00%)-1) without the 2014 energy efficiency measures alone:

Table 5 Estimated Overall Impact of 2014 Core EE Programs on Load Growth

(A)	(B)	(C) (A) x (B)	(D) (A) + (C)	(E)	(F) (D) + (E)
System Peak 2014 (note) (MW)	Forecated Load Growth 2016-2020 (%)	Forecated Load Growth First Year (MW)	Forecasted System Peak w/ EE Programs (MW)	System Peak from EE Programs (MW)	Forecasted System Peak w/o EE Programs (MW)
275.0	1.0%	2.7	277.7	1.2	278.9
					[(C) + (E)] / (A)
	Load Growth (%):		1.00%		1.43%
	Percent Difference in Load Growth:				42.9%

Note: Unitil Energy System Inc.'s summer peak occurred on July 2, 2014, hour ending 1500, coincident with ISO-NE's 2014 summer peak.

Although difficult to specifically quantify, system-wide, comprehensive energy efficiency programs can lead to deferrals of specific T&D investments over the long run, the need for which is driven by economic conditions and/or growing peak loads. Investments related to aging infrastructure, equipment failure or reliability, which represent the majority of the current investment, are generally not impacted by energy efficiency programs. As noted in the Northeast Energy Efficiency Partnerships ("NEEP") report entitled Energy Efficiency as a T&D Resource,[8] "Passive deferrals, almost by definition, will occur to some degree in any jurisdiction that has system-wide efficiency programs of any significance. However, the degree and value of passive deferrals is heavily dependent on the scale and longevity of the programs." Since UES's electric efficiency programs have been in place for thirteen years, it is likely that some planned capital investments have been deferred for a year or two over time as a result of the efficiency programs.

[8] Page 12, NEEP Report "Energy Efficiency as a T&D Resource", January 9, 2015. Available at: http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

13 CONCLUSION

The electric utility environment continues to challenge the traditional planning approach historically taken by utilities. UES believes that the approach demonstrated here demonstrates UES's balance of a traditional planning approach with an ever increasing demand side planning component.

UES's overall planning approach is resulting in a long range plan that provides safe, reliable and cost effective service to our customers. UES has and will continue to implement demand side resource pilot projects where they make sense to better understand some of the challenges listed above.

APPENDICES

A Planning and Budget Process Flow

B Unitil Electric System Planning Guide

C UES-Capital 2016-2025 Electric System Planning Study

D UES-Seacoast 2016-2025 Electric System Planning Study

E Unitil Distribution Planning Guideline

F UES Capital Distribution System Planning Evaluation 2016-2020

G UES Seacoast Distribution System Planning Study 2016-2020

H UES-Eversource Joint Planning Recommendations 2016 - 2025

I UES- Capital Reliability Study 2015

J UES-Seacoast Reliability Study 2015

K Grid Modernization Plan