STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET DE-16-383

IN THE MATTER OF: LIBERTY UTILITIES

REQUEST FOR CHANGE IN RATES

DIRECT TESTIMONY

OF

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name.

A. My name is Michael D. Cannata, Jr.

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

A. For this proceeding, I am engaged by Innovative Alternatives, Inc. (IAI) whose business address is 65A Ridge Road, Deerfield, New Hampshire 03037. I am also the president of IAI.

Q. In what capacity are you employed?

A. I have been hired by the New Hampshire Public Utilities Commission (NHPUC or Commission) to provide engineering-related services. In this proceeding, I have been requested by Commission Staff (Staff) to provide a review of energy utility engineering and operations management, practices, and procedures.

Q. Please summarize your educational and professional work experience.

A. My educational background, work experience, and major career accomplishments are presented in Exhibit MDC-1.

Q. To what professional organizations or industry groups do you belong or have you belonged?

A. I am a member of the Institute of Electrical and Electronic Engineers and its Power Engineering Society, and am a Registered Professional Engineer in the State of New

Hampshire (#5618). I served as a member of virtually all of the former New England Power Pool (NEPOOL) Task Forces and Committees except for their executive Committee, where my role was supportive to an Executive Committee member. I also served as a member of the New England/Hydro Quebec DC Interconnection Task Force and the Hydro Quebec Phase Two Advisory Committee. These two groups designed the Hydro Quebec Phase One and Phase Two 450kV DC interconnections with New England. The various committees and groups that I have served on existed to address the functions now being performed by the Independent System Operator – New England (ISO-NE).

On national issues, I represented Public Service Company of New Hampshire (now part of Eversource Energy) at the Northeast Power Coordinating Council as its Joint Coordinating Committee member, at the Edison Electric Institute as its System Planning Committee member, and at the Electric Power Research Institute as a member of the Power Systems Planning and Operations Task Force.

While employed by the of the State of New Hampshire, I managed a professional staff engaged in investigations regarding safety, engineering, operations, reliability, emergency planning, and the implementation of public policy in the electric, gas, telecommunications, and water industries. I also served as a member of the New Hampshire Site Evaluation Committee which is responsible for siting major energy facilities (electric generating stations, gas transmission lines, electric transmission lines, and gas storage facilities). At the request of the Commission Chairman, I also sat on the

State Emergency Response Commission as a designated member. I was also a member of the former Staff Subcommittee on Engineering of the National Association of Regulatory Utility Commissioners.

Q. Have you testified before regulatory bodies before?

A. I have testified before the NHPUC in rate case, condemnation, least cost planning, fuel adjustment, electric industry restructuring, and unit outage review proceedings. I have testified before the Kentucky Public Service Commission and the Maine Public Utilities Commission in transmission siting proceedings, the Maryland Public Service Commission and the Massachusetts Department of Public Utilities with respect to system reliability/storm restoration proceedings, and have submitted testimony at the Federal Energy Regulatory Commission (FERC). I have also testified at the request of the Commission before Committees of the New Hampshire Legislature on a variety of matters concerning regulated utilities.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony in this proceeding addresses several issues. The primary issue is the general process by which Liberty Utilities (Liberty) justifies its new capital reliability projects through its new system planning criteria as compared to the criteria used by National Grid prior to the Liberty acquisition and as compared to other New Hampshire electric utilities. It is my finding that by building to a much stricter standard, Liberty plans to add plant, and incur additional expenditures, that may not be necessary to ensure reliability for its customers. I also address Liberty's proposal for step adjustments through 2021.

Finally, I address Liberty's proposal to use more aggressive vegetation management practices than the NHPUC minimum requirements for vegetation management practices as they are promulgated in Puc 307.10.

III. DEVELOPMENT OF LIBERTY SYSTEM PLANNING CRITERIA

Q. Please initially discuss the National Grid System Planning Criteria[1].

A. To supply the bulk energy requirements of the Liberty system, National Grid uses a distribution planning criteria that is based on MWHs at risk after post contingency switching using peak loading conditions in the calculation.[2] The National Grid distribution planning criteria uses a 95/5 load forecast[3], equipment ratings and loadings that are consistent with the procedures used by ISO-NE for facilities under its jurisdiction, and applies its criteria to the specific geographic study areas of its system. The four former Granite State Electric Company operating areas were individually subjected to application of the former National Grid planning criteria.

National Grid tightened its planning criteria on February 15, 2011, just prior to the sale of Granite State Electric Company to Liberty, resulting in the reduction in the MWHs of load at risk. National Grid calculated the annualized net present value cost of the changes

[1] Attachment MDC-02 (Staff Data Request 8-63, Attachment Staff 8-63.1.)
[2] An example would be that a 5 MW load at peak at risk for 24 hours, would equate to a load at risk of 120 MWHs.
[3] A 95/5 load forecast is one that has only a 5 percent probability to be exceeded when looking at a normal distribution curve. Most utilities including ISO-NE have recently reduced the load probability to a 90/10 (10 percent exceedance) level from the traditionally used 50/50 (50 percent exceedance) load forecast.

to its planning criteria to be $50 million per year on an annualized basis over the next 15 years. It appears that the planning criteria changes were made to enhance reliability.

In terms of MWHs at risk for single contingency conditions[4], the newer and stricter National Grid planning criteria required that:

> For substation transformers, load at risk at peak should be limited to 10 MW, repairs be made within 24 hours, and the load at risk shall be limited to 240 MWHs after post contingency switching;[5]
>
> For sub-transmission lines, load at risk at peak should be limited to 20 MW, repairs be made within 12 hours, and the load at risk shall be limited to 240 MWHs after post contingency switching; and
>
> For distribution feeders, the load at risk shall be limited to 16 MWHs after post contingency switching.[6]

In all cases above, if the load at risk MWH criteria is exceeded, alternatives to eliminate or significantly reduce the risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate. It is also important to keep in mind that the 240 MWH load at risk values independently apply to bulk feeds into each geographic area of the National Grid system including the four geographic areas of the former Granite State Electric system.

[4] Also known as N-1 (system normal with one contingency) testing.
[5] IAI has not been able to obtain a copy of the National Grid planning criteria in effect prior to February 2011 for verification purposes, but understands from a former National Grid employee that the prior MWHs at risk was 480 MWH.
[6] In reality, customers are restored as quickly as possible through post-contingency switching which may or may not be under remote control. The 16 MWH criteria begins at that point in time, however repairs are begun on initiation of the event.

Q. Please describe the Liberty distribution planning criteria.[7]

A. Liberty based its reliability criteria on the National Grid legacy planning criteria. Liberty developed a draft version of those criteria by 2014 and has stated that its planning criteria have not changed since 2014. Liberty finalized its distribution planning criteria on August 30, 2016.[8] Liberty did not benchmark its criteria to any other utility in New Hampshire, New England, or the United States.[9] The best way to describe the Liberty planning criteria is therefore to state the changes made from the new and revised National Grid planning criteria. What Liberty has done is take the National Grid criteria used for bulk supply facilities and scaled it to its smaller distribution substation facilities. To illustrate, I restate the National Grid planning criteria described above below, and show changes made by Liberty in parentheses.

In terms of MWHs at risk for single contingency conditions, the Liberty planning criteria requires that:

For substation transformers, load at risk at peak should be limited to 10 (2.5) MW, repairs be made within 24 hours, and the load at risk shall be limited to 240 (60) MWHs after post contingency switching;

For sub-transmission lines, load at risk at peak should be limited to 20 (1.5) MW, repairs be made within 12(24) hours, and the load at risk shall be limited to 240 (36) MWHs after post contingency switching; and

[7] Attachment MDC-03 (Data Request Staff 8-63, Attachment 8-63.2.)
[8] Attachment MDC-01 (Staff Data Request 8-63.)
[9] Attachment MDC-04 (Staff Data Request 8-64.)

> For distribution feeders, repairs be made within N/A (24) hours[10], and the load at risk shall be limited to 16 MWHs after post contingency switching.

In all cases above, under both the Liberty and National Grid criteria, if the load at risk MWH criteria is exceeded, alternatives to eliminate or significantly reduce the risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.[11]

Q. Are there other changes that Liberty made to the "new" National Grid planning criteria that were adopted in February 2011?

A. Yes there are. Liberty has added the following requirements to its distribution feeder planning criteria:

> "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 wherever 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 2,000 kVA between disconnecting devices.
>
> 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 are made within 4 hours. Where longer repair times are

[10] Established new time limits for restoration times that are described in the following question.
[11] While this language appears in the Liberty planning criteria and is the same as what appears in the National Grid planning criteria, it appears to have been ignored in the Liberty capital budgeting planning process.

> needed such as for a cable getaway fault, the load out of service should be reduced to 1 MW."[12]

Liberty has also made changes in the amount of load allowed on its equipment. Although Liberty has maintained the National Grid policy of calculating the ratings of equipment consistent with ISO-NE recommended procedures, Liberty has imposed artificial restrictions on equipment load capability. National Grid allowed load capability to 100 percent of all calculated ratings, while Liberty has imposed restrictions on that load ability as described below:

> During normal operation, Liberty has reduced the allowable rating of distribution feeders from 100 percent to 75 percent;
>
> During normal operation, Liberty has reduced the allowable normal rating of sub-transmission lines from 100 percent to 90 percent, and
>
> During normal operation, Liberty has reduced the allowable normal rating of substation transformers from 100 percent to 75 percent.[13]

IAI notes that the temperatures used by Liberty for long-time emergency operation are lower than those used by Unitil and Eversource.[14] IAI understands that the distribution system must also be designed to operate at those elevated temperatures, which the Liberty system may or may not be. IAI mentions this information to point out the additional conservatism in equipment utilization built into the Liberty planning criteria. Earlier, I

[12] Attachment MDC-03 (Staff Data Request 8-63, Attachment 8-63.2, page 14.)
[13] Attachment MDC-03 (Staff Data Request 8-63, Attachment 8-63.2, page 4.)
[14] In addition, ISO-NE does not allow emergency ratings of facilities to be less than 100 ^{o}C.

stated that Liberty's probability of exceedance of the load forecast is lower than that used by others, also contributing to additional conservatism in equipment utilization.

IV. IMPACT OF NEW LIBERTY DISTRIBUTION PLANNING CRITERIA

Q. What do the changes made by Liberty to the planning criteria mean?

A. The changes made to the reliability criteria (that had been made stricter by National Grid in 2011) shows that Liberty is very aggressively pursuing reliability improvement in their distribution system heading towards the goal that all distribution feeder and distribution transformer loads have the ability for total redundancy. Liberty is also pursuing the elimination of the 23kV supply system that they purchased from National Grid so that the Liberty system becomes a totally 115/13kV supplied system. Such aggressive action will result in a distribution system that is designed to a much higher standard than those used by other electric utilities in New Hampshire and at what IAI believes will be a much higher cost.

Q. Is building redundancy into the system a bad thing?

A. No, it is not. The types of projects Liberty proposes are on point to the elevated reliability goals set by Liberty. However, I am concerned about the cost of that vision, the cost of any reaction of other New Hampshire utilities if approved by the Commission in this case in terms of approach to redundancy,[15] and the actual reliability benefits achieved by the effort. The yardstick IAI uses is "reliable and safe electric service at a reasonable cost". I also have a concern that the reliability criteria changes adopted by Liberty mask Liberty`s

[15] IAI believes that other utilities could view system redundancy as a method to add system capital projects to rate base and thus increase earnings to its shareholders.

progress to reach 5-year average reliability targets that it committed to the Commission it would achieve.

Q. What do you mean by masking Liberty's progress to reach 5-year average reliability targets?

A. In 2006, the Commission agreed to establish an REP program for Granite State Electric because its reliability metrics were sub-par compared to those of other New Hampshire utilities. The goal at that time was to encourage Granite State Electric to modify internal procedures and programs to improve its reliability metrics. Granite State Electric agreed to improve its reliability metrics to meet a previous 5-year period average. Programs like the addition of fuses, the addition of "trip saver" fuses, installation of single phase reclosers, changes to tree trimming specifications, and bare conductor replacement are typical of programs that were contemplated to be part of the REP at that time. Those types of programs are continuing to be funded under the REP to this day.

By significantly modifying the planning criteria for reliability, those planning criteria changes will produce reliability benefits that will help Liberty meet its reliability metrics commitment to the Commission, but at costs that may be prohibitive and not as intended. The construction of a system that is essentially a completely redundant, ultra-reliable system does not necessarily correct the operational deficiencies/inefficiencies recognized by Staff in 2006.

An example would be providing redundant supply sources to distribution substations. Such action would significantly reduce outage minutes that occurred due to loss of radial supply lines. At the same time, poor tree trimming practices or lack of fuse installations would increase outage minutes for those smaller outages and would be lost when reliability metrics are compiled, as the two values would be netted.

V. COMPARISON OF LIBERTY VERSUS OTHER NEW HAMPSHIRE UTILITY'S DISTRIBUTION PLANNING CRITERIA

Q. How does the Liberty Distribution planning criteria compare to other New Hampshire utilities?

A. Liberty's planning criteria are far stricter than those of Eversource and Unitil. The Unitil planning criteria allows for the loss of 30 MW of load for a period of 24 hours or a 720 MWH load at risk criteria. Similarly, Eversource Energy has the same criterion, but also limits the post contingency switching operations to three because of switching times.[16]

When one compares the essentially 720 MWH load at risk of Unitil and Eversource for the loss of a supply transformer or distribution supply line to the 60 MWH for a Liberty distribution transformer and 36 MWH for a distribution supply line, one can see that for similarly designed systems, much more equipment will be required to serve the Liberty system load than other systems in New Hampshire. Couple the design difference with the reductions from 100 percent capability to the much lower conductor temperature values adopted by Liberty, and add in the other conservative changes Liberty made to its planning criteria, even more equipment will be required to service load.

[16] 720 MWH is a maximum value. Customers are restored as quickly as possible.

Q. Please explain further how Liberty applies its planning criteria.

A. Liberty has incorporated language from the National Grid criteria about weighing reliability benefits, costs, prioritization, and evaluation but it does not seem to be performing that function when looking at alternatives to mitigate criteria violations.[17]

Further, Liberty, evaluates discretionary reliability projects using the cost of a project divided by the number of customers interrupted ($/dCI) and the cost of a project divided by the number of customer minutes interruption saved per year ($/dCMI).

Liberty stated that the projects involved in their REP had the following approximate cost dynamics:[18]

Bare conductor replacement had a $/dCI of $135.58 and a $/dCMI of $2.10;

The installation of single phase reclosers had a $/dCI of $332 and a $/dCMI of $2.77; and

Trip saver fuse installations had a $/dCI of $90 and a $/dCMI of $0.75.

In comparison, Liberty listed seven needed reliability projects in its August 2016 reliability criteria[19] that would cost $14.0 million over the next 15 years. Shortly

[17]For example, Attachment MDC-05 (Staff Data Request 11-32) states that less than three feeder ties is a criteria violation.)
[18] Attachment MDC-06 (Staff Data Request 8-75.)

thereafter, Liberty indicated that those projects would cost $19.5 million over that same time period.[20] Staff requested that Liberty break down the cost of each project, its reliability benefits, and the costs per customer interruption and customer minute saved.

Liberty responded that the seven projects would now cost $7.2 million[21] and that the costs per customer interruption for the seven projects now ranged from $480 to $1,863 and the costs for each minute of customer interruption saved now ranged from $1.32 to $26.34 on an annual basis for the new lower cost estimates[22]. Such high costs do not compare to the cost effectiveness of the projects being authorized under the REP.

Q. Mr. Cannata, are you against providing customers with a more robust and reliable electric system?

A. Of course not. I believe that utilities should do what they can to bring safe and reliable electric service to their customers at a reasonable cost. As I stated above, my concerns are with the cost of such a robust system, the reaction of other New Hampshire utilities with additional spending if the Liberty planning criteria is approved by the Commission, and the actual reliability benefits of the effort along with the attendant cost.

Q. What do you recommend that the Commission do regarding the issues you have highlighted concerning the Liberty planning criteria?

[19] Attachment MDC-03 (Staff Data Request 8-63, Attachment 8-63.2 at 21, Table 7), and Attachment MDC-08 (Staff Data Request 11-13, Attachment.)
[20] Attachment MDC-07 (Staff Data Request 11-10, Attachment, Table 4, Page 3.)
[21] Attachment MDC-08 (Staff Data Request 11-13, Attachment.)
[22] Attachment MDC-09 (Staff Data Request 11-14, Attachment.)

A. IAI recommends that any projects undertaken to satisfy the new Liberty planning criteria, that would not have been necessary to meet the National Grid planning criteria, not be included in rate base. In technical sessions, Liberty stated that no projects in service during the test year rate base were required to meet the stricter Liberty planning criteria.

Although Staff is not supporting Liberty's request for approval of its proposed 5-year step adjustment plan, to the extent the Commission accepts applications for these step adjustments (including the step adjustment proposed to be effective April 30, 2017), IAI recommends that Liberty be required to submit cost information by project, broken down into two categories: 1) the cost of each project that would have been required under the legacy National Grid planning criteria: and 2) the cost of each project that was undertaken to meet the newer Liberty planning criteria. In addition, Liberty should state and demonstrate the specific planning criteria violations for each project.

At the time the Commission reviews any step adjustments allowed by its decision in this case, the Commission can decide on cost recovery of any projects built to meet the stricter Liberty planning criteria.

VI. STEP ADJUSTMENTS

Q. You mentioned step adjustments proposed by Liberty in this case. Please expand on your recommendation concerning the step adjustments requested by Liberty.

A. Liberty is requesting five annual step adjustments for future capital projects, the first to take effect on April 30, 2017. Liberty develops its capital budgets using estimates that have an accuracy range of -50% to +100%.[23] Other New Hampshire utilities require accuracy estimates of -10% to +10% for approval of capital expenditures.[24] Given the lack of accuracy of its capital budget estimates and issues concerning budget controls as described by Jay Dudley and The Liberty Consulting Group in this case, and given the conservatism Liberty has built into its planning criteria compared to other New Hampshire utilities, and the lack of analysis made available to review prudence questions in this docket,[25] allowing cost recovery for projects put in service beyond December 31, 2016 through a step adjustment mechanism would be ill advised, in my opinion.

With regard to the step adjustment for 2016 investments (proposed for effect April 30, 2017), IAI recommends that this first step adjustment be permitted to be filed with the Commission. Based on discussions in technical sessions, IAI understands that, at most, very little of the 2016 capital expenditures were made to satisfy the newer stricter Liberty planning criteria. However, IAI recommends that the effective date be postponed until October 31, 2017 to give Liberty time to submit and the Commission to review a filing that segregates the costs described above and to provide a more robust cost justification for any projects presented for recovery in that step adjustment.

VII. LIBERTY CHANGES IN APPLICATION OF NHPUC RULE Puc 307.10

[23] Attachment MDC-10 (Staff Data Request 11-34.) IAI also understands that some estimates will be more accurate than this value.

[24] Unitil responded in its rate case, Docket 16-384, that projects seeking budget approval had to have a +/- 10 percent estimate accuracy. IAI notes that this is consistent with its experience with those of Public Service Company of New Hampshire.

[25] As examples, Staff requested all documentation for the Golden Rock substation and received a draft executive summary of a report Attachment MDC-11(Staff Data Request 3-63); Staff requested a complete copy of reliability criteria and received a summary Attachment MDC-12 (Staff Data Request 4-3); and Staff requested a copy of outage management plans and received a one paragraph response Attachment MDC-13 (Staff Data Request 4-11).

Q. What are your comments on the changes that Liberty has made to their vegetation management program practices in contrast to the requirements of Puc 307.10 regarding system reliability and system resiliency during major storm events?

A. Liberty has reviewed the minimum PUC vegetation management clearing requirements as promulgated in Puc 307.10 and determined that more aggressive vegetative management measures were required to secure the reliability of its distribution system.

In the referenced rules, the Commission requires that as a minimum, utilities under its jurisdiction maintain an 8–foot side clearance to conductors and that mid-cycle trimming be considered. Liberty has expanded its vegetation management program to include a shorter vegetation management cycle of four years.

Q. How does those costs of switching to a four-year trim cycle relate to any reliability benefits received by customers and added system resiliency during major storm events?

A. IAI cannot give the Commission a definitive answer to this question. What we do know is that reliability will be improved by this change, but the amount expended and the cost/benefit ratio is not known at this time.[26] The same is true for impacts to system resiliency during major storm events. However, IAI is also of the firm belief that tree related outages are the greatest cause of outages during normal system events and a major impediment to restoration of long-term outages due to severe weather related events.

[26] IAI also notes that Unitil Energy System decided that it also needs to use more aggressive vegetation management practices than the NHPUC minimum vegetation management requirements, but in a different manner than Liberty.

Q. What does IAI recommend?

A. Keeping in mind that Unitil Energy System has also decided to adopt more aggressive, although different, vegetation management practices than required by NHPUC rules[27]; IAI recommends that Liberty track the reliability performance of circuits that have been trimmed to the new Liberty 4-year standard on a go-forward basis as compared to the performance that would have been expected under the minimum vegetation management requirements in Rule 307.10 and report the findings in its annual Vegetation Management Plan filed with the Commission each November.

Q. Does this conclude your testimony?

A. Yes, it does.

[27] IAI comments to the Unitil changes to the vegetation management practices required by Commission Rule Puc 307.10 are included in my testimony in Docket DE 16-384.