STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET DE-16-384

IN THE MATTER OF: UNITIL ENERGY SYSTEMS, INC.

REQUEST FOR CHANGE IN RATES

DIRECT TESTIMONY

OF

Michael D. Cannata, Jr., P.E.
President
Innovative Alternatives

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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 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, operations, reliability, emergency planning, and the implementation of public policy in the electric, gas, telecommunications, and water industries. I also served as a full member of the New Hampshire Site Evaluation Committee responsible for siting major energy facilities (Generating stations, gas transmission lines, electric transmission lines, and gas storage facilities). At the request of the Commission Chairman, I 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 as required 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 addresses a multitude of issues. The primary issue that is addressed is the general process by which Unitil Energy Systems, Inc. (UES) budgets its required and discretionary capital projects across its electrical distribution system. Other areas addressed include the specific additional major capital project additions of the new Kingston 115/34.5kV Substation interconnecting with Eversource Energy (Eversource) in the Seacoast operating region to be completed in 2016 and the new Broken Ground 115/34.5kV Substation interconnecting with Eversource in the Capital operation region to be completed in 2017. A portion of the Kingston Substation cost is included in the filing as a post-year adjustment to the 2015 test year rate base reflecting plant in service in April 2016. The remainder of the project costs are requested in future step adjustments to rates in subsequent years. The total cost of the Broken Ground Substation is requested through future step increases coinciding with project completion during subsequent calendar years. Another consideration with these two major capital projects is that UES has made the decision to own the interconnections and take delivery at the 115kV voltage level rather than to rely on Eversource for delivery service at the 34.5kv voltage level and paying Eversource delivery service charges.

UES is also using higher standards than the NHPUC minimum requirements for vegetation management practices as they are promulgated in Puc 307.10 (a) (2). I offer my comments on that subject and the impacts on reliability and system resiliency during major storm events.

III. CAPITAL PROJECT BUDGETING PROCESS

Q. Please discuss the capital spending process at UES.

A. I have reviewed the process used by UES in the funding of both required and discretionary capital projects. Excluding the major capital projects consisting of the new Kingston Substation and Broken Ground Substation projects, I found that UES funds capital projects in a uniform manner consistent across the total New Hampshire corporate entity.

Q. What does consistent across the total corporate entity mean?

A. What I mean is that projects that are not needed to maintain reliability standards or other mandated requirements like safety and environmental considerations are evaluated on a corporate-wide basis. UES is comprised of two separate operating areas. Those are the Seacoast and Capital operating areas. Each project is cost estimated and prioritized on the same basis and then funded to the extent allowed by the total capital budget with consideration of the overall benefits obtained. In other words, both operating areas are treated as a single operating area in the process resulting in an efficient allocation of financial capital across the UES distribution system.

Q. What about the process used for major capital projects like the new Kingston and Broken Ground Substations?

A. For these larger projects, the need and timing is determined by the application of UES reliability standards requiring that equipment must not be overloaded, voltages must remain within required tolerances, and that load loss over a 24-hour period must not exceed 30MW for specified contingencies. Studies are performed annually for each of the Seacoast and Capital operating areas, testing the system over a 10-year time horizon. A 90/10 load forecast[1] is performed and the power system lines and transformers are mathematically simulated. The single contingencies[2] required to be modeled by the reliability standards are simulated in the model to ensure that the electrical distribution system meets the aforementioned reliability standards throughout the 10-year period. Because the UES system can also experience equipment loading issues with no system

[1] A 90/10 load forecast is one that has only a 10 percent probability to be exceeded when looking at a normal distribution curve. A 50/50 load forecast would therefore have a 50 percent chance of being exceeded.
[2] Also known as N-1 (system normal with one contingency) testing.

elements out of service (N-0 testing), they also perform analyses without contingencies using their extreme peak load forecast which is simply a load forecast that has a probability of exceedence of 4 percent.

After the electrical distribution system's needs are identified for the future, these identified needs are then monitored annually, go through the planning and approval process, and are budgeted to be in service when required. This process requires that planning and construction of large projects are done over a multi-year period, resulting in corresponding capital expenditures over that expanded time period. Large projects such as the two new 115/34.5kV substations require significant capital expenditures over multi-year periods.

IV. NEED FOR NEW KINGSTON SUBSTATION

Q. Please discuss the system reliability issue that requires construction of the new Kingston Substation.

A. The topic of the new Kingston Substation was first discussed in the last UES full rate case, Docket DE 10-055. In that proceeding, UES studies had indicated that the new facility was going to be required to be in-service in 2012 because the existing Eversource transformer at Kingston would reach its maximum Eversource determined normal loading capability without a system contingency at that time.

The Seacoast operating area is fed by three Eversource sources. The Eversource Great Bay 40 MVA 115/34.5kV Substation feeds the northern area, two Eversource 345/34.5

125 MVA transformers at Guinea Road Substation feeds the eastern portion of the system, and a single 40 MVA Eversource 115/34.5kV transformer at the Kingston Substation feeds the western portion of the system.

The existing Kingston transformer was jointly planned and is jointly used by Eversource and UES so that the joint service area is designed and operated to produce lowest total overall costs to both companies. When the Kingston facility went into service in 1977, the western area of the UES Seacoast system were fed by Eversource sources on the eastern portion of the system and a 34.5kV tie circuit back to the Chester 115/34.5kV Substation in Chester. The new facility at Kingston allowed both the Eversource Chester area and the UES western portion of its Seacoast system to be simultaneously reinforced. Load growth in the Derry area since that time has required that Eversource utilize a larger portion of the available capacity at the Kinston Substation while additional load growth on the UES system in the western portion of its system has also increased. When substation use by company (as determined at peak load periods) changes at the joint use facility, the load based cost sharing agreement is recalibrated. There are no restrictions on either company to utilize the capacity of the joint-owned facility.

In the 2010 rate case, Staff reviewed the need for a new transformer at Kington in 2012 and determined that there were measures that UES could take to defer the need for the facility. By refining its load forecasting process and distributing its load more efficiently among available transformer capacity of all the Eversource sources, UES has deferred the timing for the facility to 2016. In addition to evaluating joint substation alternatives, UES evaluated an alternative that considered owning its own substation rather than owning just its own 34.5kV facilities plus paying Eversource a load-based share of the Eversource facilities. This alternative was ultimately chosen by UES.

Q. Did you review the analyses performed by UES to establish the need and timing for the new Kingston Substation?

A. Yes, I reviewed each annual analysis performed by UES since the last rate case in the Seacoast operating area. I also reviewed the revised UES load forecasting methodology[3] and the parameters used in calculating thermal ratings for system components[4] such as ambient temperatures and conductor temperatures[5]. My review also included a review of the analyses performed by UES regarding the use of alternative supply. I concluded that the studies and analyses were reasonable, sound from an engineering perspective, used reasonable assumptions in its input data, and drew proper conclusions from the results of those analyses. Therefore, I therefore support the UES decision to move forward with this project for completion in 2016 as the proper installation timing for the new Kingston Substation.

V. NEED FOR NEW BROKEN GROUND SUBSTATION

Q. Please discuss the system reliability issue that requires construction of the new Broken Ground Substation.

[3] Data Request Staff 8-2, Attachment 2.
[4] Data Request Staff 8-2, Attachment 3.
[5] Conductor operating temperature is the allowable temperature that the conductor is allowed to operate at under normal (continuous) conditions, long-time (12-hour summer and 4-hour winter) conditions and short-time (15 minutes) conditions. Generally, no loss of life of the conductor is permitted for continuous operation conditions, while some life loss is accepted for shorter emergency operating conditions.

A. The Capital operating area is fed by two Eversource sources. The two Eversource Garvin's Falls Substation 60 MVA 115/34.5kV transformers feeds the southern portion of the Capital operating area in Concord and two Eversource 115/34.5 40 MVA transformers at the Oak Hill Substation in Penacook feeds the Northern portion of the system. The existing transformers were jointly planned and are jointly used by Eversource and UES to produce lowest total overall costs to both companies in this area of New Hampshire. In addition, there was a potential for some additional capacity from an Eversource 34.5kV tie to the Oak Hill 115/34.5kV Substation in Penacook. The facilities allow both the Eversource and the UES systems to be simultaneously reinforced. Load growth in the Concord suburb area has required that Eversource utilize a larger portion of the available capacity at these substations while additional load growth on the UES system has increased as well which has also increases substation loadings.

In addition, system reconfiguration in the Capital operating area has been required in order to address system restrictions during 115kV outages on the Eversource 115kV transmission system. These restrictions are similar to those that required the split of the UES Seacoast operating area. When use (determined at peak load) changes at the joint facility, the load-based cost sharing agreement is recalibrated. There are no restrictions on either company to utilize the facility.

According to UES, loss of one of the supply sources to this area of the system would create loadings on the remaining supply sources at a level that is very close to Eversource's pre-determined transformer ratings. This would also create overloading to various sections of UES 34.5kV lines. In addition to evaluating joint substation alternatives, UES considered owning its own substation as an alternative to owning just its own 34.5kV facilities and paying Eversource a load based share of the Eversource facilities. This alternative was ultimately chosen by UES.

Q. Did you review the analyses performed by UES to establish the need and timing for the new Broken Ground Substation?

A. Yes, I reviewed each annual analysis performed by UES since the last rate case. As stated above, I also reviewed the revised UES load forecasting methodology and the parameters used in calculating thermal ratings for system components such as ambient temperatures and conductor temperatures. My review also included a review of the analyses performed by UES regarding the use of alternative supply. I concluded that the studies and analyses were reasonable, sound from an engineering perspective, used reasonable assumptions in its input data, and drew proper conclusions from the results of those analyses. Therefore, I support the UES decision to move forward with this project for completion in 2017 as the proper installation timing for the new Broken Ground Substation.

VI. UES CHANGES IN APPLICATION OF NHPUC RULE Puc 307.10 (a) (2)

Q. What are your comments on the changes that UES has made to their vegetation management program practices in contrast to the requirements of Puc 307.10 (a) (2) regarding system reliability and system resiliency during major storm events?

A. UES has reviewed the minimum PUC vegetation management clearing requirements as promulgated in Puc 307.10 (a) (2) and determined that more aggressive vegetative management measures were required to secure the reliability of its distribution system.

Q. Please describe what those changes are.

A. 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. UES has expanded its vegetation management program to include vegetation to a side-depth of 10-feet and has added a mid-cycle vegetation inspection to identify vegetation management issues that may cause interruptions before the next maintenance cycle is started.

Q. The changes you describe also involve costs. How do those costs relate to the reliability benefits received by customers and 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 these changes, but the amount expended and the cost/benefit ratio is not known at this time.[6] 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.

[6] IAI also notes that Liberty Utilities had also decided that it also needs to use more aggressive vegetation management measures than the NHPUC minimum vegetation management requirements but in a different manner than UES.

These benefits are often excluded in the decision calculations regrading vegetation management maintenance programs.

Q. What then does IAI recommend?

A. Keeping in mind that Liberty Utilities has also decided to adopt more aggressive, but different than UES vegetation management practices than required by NHPUC rules[7]; IAI cannot give the Commission a definitive answer to this question at this time.

What IAI does recommend is that UES track the reliability performance of circuits that have been trimmed to the new UES standards on a go-forward basis as compared to the expected performance of NHPUC minimum vegetation management requirements.

Q. Does this conclude your testimony?

A. Yes, it does.

[7] IAI comments to the Liberty Utilities changes to the vegetation management practices required by Commission Rule Puc 307.10 (a) (2) are included in the testimony in Docket DE 16-383.