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STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 10-055

UNITIL ENERGY SYSTEM, INC.

2010 DISTRIBUTION RATE CASE

DIRECT TESTIMONY

Of

Michael D. Cannata, Jr., P. E.
Senior Consultant
ACCION GROUP, INC.

November 5, 2010

Q. Mr. Cannata, please state your full name.

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

Q. Please state your employer and your business address.

A. For this engagement, I am engaged by The Accion Group (Accion) to address the issues raised in this proceeding. My business address is 65A Ridge Road, Deerfield, New Hampshire 03037.

Q. In what capacity are you employed?

A. I am generally responsible for the review of energy utility engineering and operations management, practices, and procedures.

Q. Please describe your educational background, work experience, and major accomplishments of your professional career?

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 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 (PSNH) 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 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 sat 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 Chairman of the New Hampshire Public Utilities Commission's (NHPUC or Commission), 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, unit outage reviews. I have testified before the Kentucky Public Service Commission and the Maine Public Utilities Commission in transmission siting proceedings, and have submitted testimony at proceedings 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.

Q. Please describe the areas that your testimony addresses today.

A. My testimony addresses three main areas and a number of related issues. Accion was requested to review (1) the reliability of the Unitil Energy System (UES) distribution system and the Reliability Enhancement Plan (REP) that UES proposes to implement, (2) the UES proposed revisions to its Vegetation Management Plan (VMP), and (3) the Large Capital Project step adjustment requirement for the Kingston and East Kingston substations in 2012. I also present testimony on a number of other topics.

Q. Please summarize your system reliability and Reliability Enhancement Plan testimony.

A. System reliability is normally expressed through the use of system reliability indices. The most common in use are the System Average Frequency Interruption Frequency Index (SAIFI), which is a measure of how many times in a given period of time the average customer can expect to experience an outage, and the System Average Interruption Duration Index (SAIDI), which is a measure of how long a customer can be expected to be without service if a permanent outage occurs.[1] These two indices may be expressed over different time periods, but generally an annual period is used. Likewise, the reliability indices may be expressed on a system-wide basis, an operating area basis, or on a circuit basis.

Reliability indices can be impacted by events outside of a utility's control, such as storms or actions by transmission providers where the transmission supply is not directly owned by the utility. The Commission requires that its jurisdictional electric utilities report their reliability indices without the impact of major storms and also without the impact of transmission provider outages. Reliability indices can also be impacted by events within the control of the utility, such as amount and frequency of tree trimming, quality and frequency of equipment inspections, and the amount of expenditures dedicated to replacement of aging infrastructure.

As shown in the response to Data Request STAFF 3-27, UES system reliability without the impact of major storms was improving in the late 1990s and began to degrade after the year 2000. However, UES was not able to recognize the trend in degradation at the time that it filed its 2005 rate case because the trend was not visible until after 2004. The trend data available at the time of the 2005 rate case is illustrated in the UES response to Data Request STAFF 3-59 which shows a steadily improving reliability metric with major storms excluded.

In 1996, the Commission became concerned about the reliability levels of its electric utilities and approved a 5-year stipulation that included all electric companies and the New Hampshire Office of the Consumer Advocate (OCA). The stipulation established a foundation from which the utilities could assess and understand the factors that influence reliability on their respective systems. Both Concord Electric Company (CEC) and Exeter & Hampton Electric Company (E&H) (together UES) participated in that effort and as a result made vegetation management practices common to both systems. During the 5-year period covered by the stipulation, each system was to have a complete trimming cycle performed on the entire system. The UES companies performed the required trim cycle and maintained that cycle until February 1, 2007. At that time, UES differentiated between the 3-phase and single phase portions of its distribution system, as well as the existing differentiation of voltage with respect to trimming frequency requirements. The result was longer than the 5-year recommended trimming cycles for the single phase portions of the system. UES also maintained vegetation management funding at a constant level after 2000.

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[1] A permanent outage is usually defined as 5 minutes or more so that momentary interruptions (a fault that is automatically cleared) are not captured in the calculations.

The UES actions resulted in less than the required cycle trimming performed, and a lower real dollar funding level precipitated the 2007 change to the trimming cycle in an attempt to perform more trimming for the same amount of money.[2]

Accion believes that enhanced attention to tree trimming was the main reason for the reliability improvement that occurred during the 1990s. Accion further believes that the constant vegetation management funding provided by UES after the stipulation expired in 2000 until the present time has been eroded by inflation, and, as a result, increased costs related to the tree trimming function have further reduced the amount of trimming performed. Reliability deteriorated as the result of insufficient funding which resulted in the 2007 UES decision to lengthen the trimming cycles of its single phase system.

Q. Are there other factors that you believe contributed to the recent degradation of reliability on the UES system?

A. Yes. There are three and they are closely related. For that reason, I lump them into the same category - the lack of available funding to initiate projects that could be called discretionary when compared to other functions that a utility performs.

A utility has many projects and programs to perform that result from 1) regulatory, 2) environmental, 3) safety, or 4) legal requirements. These requirements are considered non-discretionary as the utility has no ability to either not perform them or to defer

[2] Please refer to Data Response STAFF 3-30.

them. The three requirements mentioned directly below that I call discretionary are labeled such because there is no requirement that the projects must be performed at that moment in time. Those discretionary requirements are 1) reliability enhancement or improvement requirements, 2) replacement of aging infrastructure, and 3) REPs. These factors are dependent on the generation of funds from ongoing operations based on rates.

Aging infrastructure is usually old and fully depreciated. As such, it generates no capital through depreciation in the utility revenue stream, yet the replacement cost of the infrastructure is many times its original cost. Between rate cases, improved cash generation is dependent on load growth and during economic slowdowns, that growth is often negative, thus compounding the difficulty in raising needed capital for discretionary projects. Difficulty in raising the capital necessary for replacement of aging infrastructure has been further compounded by the recent shift from a winter peaking system to a summer peaking system. Summer peaking systems have a lower utilization rate of equipment due to reduced power carrying capability in higher ambient temperatures.

A similar argument can be made for the replacement of problematic equipment where an "operate until failure" policy is often adopted. Likewise, a similar argument can be made for the REPs. Lack of sufficient capital generation is the reason why utilities request additional revenue during rate cases as UES has done in the instant docket. Non-discretionary projects are funded first. With limited funding, the so-called discretionary projects are not able to be funded and as a result, a slow degradation of system reliability occurs.

The UES system shows signs of the phenomenon described above. The UES response to Data Request STAFF 4-46 shows that UES identifies many projects where a reliability problem exists, but only funds the projects that are the most beneficial economically. In addition, the UES response to Data Request STAFF 1-26 depicts the up and down nature of REP funding, including a sharp increase in funding in 2010.[3] Both responses exhibit characteristics of capital constraints. Data Request STAFF 4-45 shows a sharp increasing in reliability funding in 2010."

I have also reviewed the UES proposed REP and do not disagree with the types of programs UES proposes to initiate. I also believe that the level of proposed funding is reasonable.[4] However, I am concerned that UES is trying to address all of the identified reliability areas needing improvement on its system in parallel. I believe a more focused approach in the implementation of the REP programs is required in order to “get the biggest bang for the buck.” In that manner, some of the more expensive programs may be able to be deferred or eliminated if reliability levels are adequate after implementation of the less expensive programs. Specifically, I believe that the UES REP has a heavy emphasis on circuit hardening due to what I call an “address everything approach.” It is my experience in similar situations that

[3] See: Staff 4-45.
[4] Please see Data Response STAFF 3-51.

reliability improvement is more quickly obtained through more aggressive tree trimming, the fusing of taps, and the installation of reclosers where warranted.[5] After these steps are taken, more expensive reliability improvement measures such as circuit hardening can be undertaken, if warranted.

I also make note of the UES NESC-required safety inspection structure. UES separates its required NESC safety inspection from the inspections it performs for identification of reliability corrective maintenance issues. Upon review of the UES inspection maintenance sheets, I find them to be weak, because many common maintenance issues are not flagged as specific items on the sheets and require handwritten notations by the inspectors.

Q. What are your conclusions and recommendations regarding the reliability of and the improvement of reliability of the UES system?

A. One conclusion is that the recent degradation of the reliability on the UES system is real and most likely a result of the main factors that I discuss above. I also conclude that reliability will continue to deteriorate without some sort of a reliability enhancement plan funded above traditional rate levels. The question that remains to be answered is at what level above that which can be justified from traditional rate making should reliability improvement be funded? I accept the funding level proposed by UES as reasonable to address reliability improvement, but recommend increasing the amount of funding for vegetation management, as described below. I

[5] In addition to known equipment problem replacement programs.

believe the amount of funding proposed for vegetation management is insufficient to address what is the largest determinant of system reliability[6] in a timely fashion.

I also conclude that, after review of the UES REP, the programs they state will be in their plan are the correct ones, but reliability improvement should be done by more aggressive tree trimming, as described below, fusing unfused taps, and the installation of circuit reclosers. I recommend that the final determination of the details of the REP be determined in a more comprehensive manner through discussions with and agreement of Commission Staff.

With regard to the UES NESC inspection process, I recommend that a more detailed review of the process be undertaken through the focused operations and engineering audit recommended below.

Q. What was the result of your review of the proposed Vegetation Management Plan?

A. UES engaged Environmental Consultants, Inc. (ECI) to provide a draft proposal for a comprehensive integrated VMP. ECI covered virtually every aspect of the requirements for a VMP and made a comprehensive proposal on May 18, 2010.[7] The ECI proposal is contained in the confidential response to Data Request STAFF 1-29.

[6] Over the last 5 years, Data Request STAFF 1-25 shows that tree related outages have accounted for 30% to 45% of system outage duration.

[7] The ECI report was not available until after the UES rate case filing in April 2010.

In preparing its rate case filing, UES did not have the final ECI report in hand. In filing Exhibit MHC-12, UES made an estimate of the cost of the VMP based on preliminary information. That estimate totaled $2,250,000. In response to Data Request OCA-3-2, UES updated the cost of the VMP to $2,634,800,[8] based on information contained in the final ECI report. UES did not adopt all the recommendations of the ECI report, but rather used it as a basis for its own VMP. UES developed its VMP based on different trimming cycles than that recommended in the ECI report. [9] UES based its VMP on a 4-year trimming cycle for 3 phase facilities, a 7-year trimming cycle for single phase facilities[10], and a 7-year hazard tree removal program that is the basis for the $2,643,800 updated VMP estimate.

Q. Please compare current UES trimming cycles and clearances with those proposed in the UES VMP.

A. The following table makes the requested comparison.

UES Current vs. Proposed VMP Trimming Cycles and Clearances

	Current UES VMP[1]			Proposed UES VMP[2]		
Voltage Level and Configuration	**Cycle (Yrs.)**	**Side Clearance (Ft.)**	**Top Clearance (Ft.)**	**Cycle (Yrs.)**	**Side Clearance (Ft.)[3]**	**Top Clearance (Ft.)[3]**
4.16kV – 3 Ph.	8	8	15	4	8	15
4.16kV – 1 Ph.	10	6	6	7	6	6
13.8kV – 3 Ph.	5	8	15	4	8	15
13.8kV – 1 Ph.	7	6	6	7	6	6
34.5kV – 3 Ph.	4	8	15	4	8	15
34.5kV – 1 Ph.	5	6	6	7	6	6

1 – Data from Data Request STAFF 3-75.
2 – Data from Data Request TS-13.
3 – Staff understands that clearances will remain the same under the proposed VMP.

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[8] This value is broken down into VMP components in the UES response to Data Request TS-5.

[9] ECI proposed a 4 year trim cycle for 3 phase facilities, a 7 year trim cycle for single phase facilities, a 7 year hazard tree program, a mid-cycle trimming program, and increased clearances for fast growing species. I do not believe that UES included the last two aspects of the ECI recommendation. (See: STAFF 12-29)

[10] UES is also using less to the side of and above single phase conductors compared to 3 phase conductors.

Q. On what Does UES base its longer trimming cycle for single phase facilities?

A. UES relies on a 2004 I.E.E.E. article supplied in response to Data Request TS-7. In essence, the article lists the conditions that impact the ability for a tree limb to create a fault path. Those conditions are:

- Voltage gradient
- Branch diameter
- Surface moisture
- Branch condition (living or dead)
- Branch origin (normal vs., sucker growth)
- Internal wood moisture content
- Seasonal variation and effect on impedance
- Species variation (eleven species)

Laboratory results indicated that the greatest impact on fault current levels through tree branches were voltage gradient, branch diameter, and tree species. Field tests were also performed. The results of the field tests confirmed that the amount of fault current present remained relatively stable, did not exceed 0.5 amps, would likely remain a high impedance fault, and at no time approached levels that would be detected by protection equipment. The article concludes that there is a low risk that branches on single phase power lines will cause outages or that power quality will be impacted. The article further concludes that there is substantial risk of an outage if a branch makes contact between 2 phases or when a branch makes contact with a single phase and the system neutral.

Q. Do you agree with the research and with the extension of single phase trimming cycles based on that research?

A. Looking solely at the research performed, I cannot disagree with the results per se, but I do believe that application of the research is problematic and, because of that, I do not agree with application of this research to the UES system.

Q. What do you find problematic with the research?

A. First, I believe that power quality will suffer from lengthier trim cycles. While power quality will not be impacted where no fault generated by a limb on a line, there will be power quality impacts when branches sit on a power line and burn. A few inches of vegetation may burn off only to result in a fault after additional growth occurs. I believe that substantial customer dissatisfaction may result by allowing vegetation growth into the conductors. The research did not consider this aspect of power quality in its application.

There are also two safety issues that I do not believe were considered to the extent they should have been. The National Electrical Safety Code C2-2007 (NESC) requires that vegetation that can damage ungrounded supply conductors should[11] be pruned or removed, and that vegetation management be performed as experience has shown to be necessary. The NESC further states that factors to consider in determining the extent of vegetation management required include, but are not limited

[11] A "shall versus should" argument is often made here. If the "should" definition is adopted, trimming of vegetation that can cause damage to the conductor becomes discretionary action by the utility and allows for no vegetation management to be performed.

to: line voltage class, species' growth rates and failure characteristics, right-of-way limitations, the vegetation's location in relation to the conductors, the potential combined movement of vegetation and conductors during routine winds, and sagging of conductors due to elevated temperatures or icing.[12] In my interpretation, these factors are the ones that should be used to determine trimming cycles and trim zones to keep vegetation away from the supply conductors. They should not be used as justification to allow vegetation growth into the conductors. Letting conductors knowingly come in contact to supply conductors will cause arcing, which causes conductor damage contrary to the intent of the NESC.

The second safety issue relates to safety of the general public. If branches are knowingly allowed to touch energized conductors for long periods of time, generating trickle currents in the contacted vegetation, I believe that risk of shock to the public can be significantly increased and as such is not considered good utility practice.

I recommend that the Commission adopt a 5-year across-the-board VMP that treats tree contact as an unsafe condition.

Q. What is the financial impact to the UES rate request if the Commission adopts your argument with respect to the UES proposed VMP versus the across-the-board 5-year VMP you recommend?

A. I first wish to point out that the impact of the 5-year VMP I propose also has benefits

[12] NESC Rule 218.A.

associated with the cost of such a program. The benefits are that the system is fully trimmed sooner and hazard[13] trees are eliminated two years sooner than what UES proposed from the system. Both of these items account for a significant portion of the degradation in reliability being experienced. In regard to cost, Staff requested that UES provide a total 5-year cycle enhanced VMP cost comparison to the UES proposed VMP. UES responded in its response to Data Request TS-13 that the 5-year program would cost $3,184,800, representing an increase of $541,000 over the UES proposed VMP as revised.[14] I note that the 5-year VMP proposed by Staff utilizes the same side and top clearance requirements as the VMP proposed by UES . Further discussion is required with Staff to resolve apparent UES side clearance discrepancies and why differences among utilities are appropriate. Changes in clearance requirements may increase cost still further.

UES proposes a significant increase to its current under-funded vegetation management program. Staff concluded that the UES proposal is insufficient to address in a reasonable time frame the reliability problems caused by vegetation and proposes a more aggressive and therefore more costly program. UES may not be able to “ramp up” its internal and external work force very quickly. This is another area where a phase-in program should be discussed with Staff.

[13] According to the UES response to Data Request STAFF 3-77, ECI estimated that there exists 31,521 hazard trees on the UES system of which, 9,176 hazard trees reside on the 3 phase portion of the system.
[14] It appears that the figures were developed by the application of ratios and not a separate estimate.

Q. Are there other issues related to the UES VMP that you wish to comment on?

A. Yes, there are two. One deals with NESC Rule 218.B. This rule requires that the crossing span and each ajoining span should be kept free of overhanging vegetation at railroad and limited access highway crossings. UES responded to Data Request STAFF 3-78 that their VMP does not directly address this issue, but states that its normal practices include such trimming. I would recommend that UES explicitly include this provision of the NESC in its VPM. I would also recommend that UES evaluate the application of NESC 218.B at all road crossings in its REP to improve restoration times and help prevent the stranding of customers.

The next item deals with the number of people UES plans to add regarding its VMP. UES plans to add one System Arborist who will charge 2/3 of his or her time to UES and 1/3 to Fitchburg Gas and Electric. UES also plans to add a vegetation coordinator in Fitchburg and one at UES.[15] Staff points out that PSNH has approximately 11,000 miles of overhead distribution lines and believes that PSNH performs its VMP with three individuals. UES has only 1,050 miles of distribution line in New Hampshire. I recommend that UES revisit its personnel number requirements regarding implementation of its VMP to evaluate if some program savings can be achieved.

[15] Please see UES response to Data Request TS-5.

Q. Please explain what the Large Capital Project step adjustment is and what it is intended to be used for.

A. Certainly. The Large Capital Project step adjustment proposed by UES is intended to treat the revenue requirement for the Kingston and East Kingston projects through a step adjustment in 2012, rather than through traditional rate making methods.

Q. Please describe the projects that UES proposes to include in its Large Capital Project step adjustment.

A. There are two projects that UES proposes to include in its Large Capital Project step adjustment. Those projects are the East Kingston project and the Kingston project. I describe both projects below, the reason for their need, and project timing. I note that the cost and scope of the Kingston project has markedly changed since the initial UES filing.

The East Kingston substation is a 34.5/13.8kV substation in East Kingston, New Hampshire.[16] At the present time, there is one 13.8kV circuit emanating from the substation. UES projects that by 2012, the loading on this circuit will reach its power carrying capability on an all-lines-in-service (normal) basis.[17] UES bases its projections on localized load and customer data and notes that the addition of one good sized customer can utilize the remaining capability in the circuit. UES proposes to add an additional 13.8kV circuit to this substation.[18]

[16] The 34.5 kV source for this substation is the Kingston substation.
[17] Data Response STAFF 1-31.
[18] A graphical representation of the project is contained in the response to Data Request STAFF 4-50.

The Kingston project increases the 115/34.5kV transformation capacity at the Kingston substation in Kingston, New Hampshire. Using its corporate load forecast, UES projects that the all-lines-in-service (normal) loading of the existing PSNH 40 MVA transformer will exceed the transformer rating of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] MVA in 2012.[19] The original proposal in the UES filing envisioned that [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[20] The scope and cost of this project has changed considerably since the UES filing.

Q. How has the scope and cost of the Kingston project changed?

A. Exhibit MHC-11 depicts the costs of the projects and the impact on rates through the Large Capital Project step adjustment at the time of the UES filing. That exhibit shows the cost of the Kingston project that is allocated to UES to be $2,447,000, the cost of the East Kingston project to be $1,362,200, and the step adjustment to rates to be $692,945.

Data response TS-11 shows that PSNH has now redesigned the project to include an additional two 115kV breakers, changed the size of the 115/34.5kV transformer to 60 MVA from 40 MVA, and added a full 34.5kV bus complete with a bus tie breaker. The total project cost is now estimated to be $23,050,000 with $3,950,000 allocated to UES. The cost of these configuration changes increases the Large Capital Project

[19] Data Request STAFF 1-31.

step adjustment from $692,945 to $937,681, an increase of $244,736. With the transmission rate structure in New England, the UES cost is a result of the changes to the 34.5kV portion of the substation as the remaining portion of the project would now be considered Pool Transmission Facilities[21] and be paid for by all New England electricity customers. The UES portion of the project is only paid for by UES customers. UES states that it has not approved the PSNH reconfiguration of the project.[22]

Q. Are you comfortable with the reconfiguration of the Kingston project performed by PSNH? Please explain your response.

A. No, I am not. I will discuss each configuration change separately. The change of the transformer size has no apparent justification and I believe the originally proposed 40 MVA transformer would put additional system needs way beyond the planning horizon. The addition of a full 34.5kV bus complete with a bus tie breaker may provide some marginal reliability benefits; I see no justification for its existence especially since it is fully redundant to the UES facilities just feet away.

Q. Please continue with your discussion on the Large Capital Project step adjustment.

A. Certainly. I was just about to address the need and timing for each project. The East

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[20] A graphical representation of this project is contained in the response to Data Response STAFF 4-50.
[21] As configured in the filing, the entire PSNH portion of the project would not be considered Pool Transmission Facilities, would not be paid for by all New England customers, and would not qualify for the extra 1% ROE allowed by FERC.
[22] Data Request TS-11.

Kingston project is based on local load and customer data. UES stated that it looked at alternatives to the proposed project, including photovoltaic opportunities, wind power, generation from landfill gas, natural gas generation, and thermal energy storage. UES further stated that it found these alternatives to be not practical, feasible, or economic. In addition, UES looked at transferring load to another portion of its system and found that little improvement in the loading problem could be made.[23]

My review indicates that the second circuit is needed, that it is the preferred alternative, and that the 2012 timing is reasonable. I therefore support inclusion of this project in the Large Capital Project step adjustment as proposed by UES. However, if circumstances change and if UES is able to defer the project, I would expect them to do so thus saving customers approximately $247,000 in rate increases.[24]

The need for the Kingston project is driven by the use of the corporate load forecast, the UES planning criteria, and the rating of the Kingston transformer. I believe the first two drivers are flawed and that those flaws result in a need date earlier than it would be otherwise. In addition, an update to the UES load forecast used to justify the project also indicates that deferment is possible. The need date of 2012 was determined **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2012 with

[23] Data Request OCA 2-53.

[24] The approximate $247,000 increase is the ratio of the Kingston project cost to revenue requirements, both of which are contained in MHC-11.

the UES load forecast and application of the UES planning criteria.[25] That overload would be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

I begin with the UES planning criteria. The document requires the design of the system under contingency conditions to an N-1 standard[26] at a peak load that has only a 10% chance of being exceeded. This is the so called 90/10 load level and UES calls this load level the Design Peak load level. In addition, UES requires that its system withstand an extreme peak conditions under all-lines-in-service conditions. This condition is the so called N-0 design. UES defines the Extreme Peak load as the load level that could be expected to be exceeded once in 25 years (4% probability of exceedence) or the 96/4 load level.[27]

The UES planning criteria is overly conservative with the use of the Extreme Peak load design provision. In fact, ISO-NE uses a less conservative design criterion for the bulk power facilities that engage in inter-pool bulk power transfers. At ISO-NE, a 90/10 load level is used for system design. For loads above that used for design, ISO-NE is required to analyze extreme loading conditions and develop plans as appropriate to mitigate negative consequences.[28] The ISO-NE is not required to design the system to withstand those load levels. The application of requirements that are stricter than those used in bulk power system planning to the UES distribution

[25] Data Request STAFF 1-32.
[26] An N-1 standard represents a single contingency where all elements must remain within applicable ratings and voltages must remain within applicable limits.
[27] Data Request STAFF 3-67.

system is overly conservative and should not be used as a design basis. UES states that if the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** using the parameters and load forecast used in the design study presented as the UES response to Data Request STAFF 1-31.[29]

The UES corporate load forecast in 2009 was used for the system study for the Kingston project. The UES load forecast is described as follows. UES develops a load versus temperature model of the previous year using the daily peak loads and the daily average temperatures of the summer months, excluding weekends and holidays. A Monte Carlo process is utilized to incorporate historical information to develop an average load forecast (50/50), an Extreme Peak load forecast (90/10), and an Extreme Peak load forecast (96/4) at a 90% confidence level. UES then applies the 10-year historical load growth to those values with weighting for the more recent data. No economic or econometric data is applied to the UES corporate load forecast.[30]

Since 2009 when UES performed the Kingston analysis, and at the request of Staff, UES updated its load forecast for the seacoast area. Even without considering economic and econometric data for the near term forecast and using historic growth indicators, the load forecast has declined. The table below shows the difference

[28] ISO-NE Planning Procedure 3, Reliability Standards for the New England Area Bulk Power Supply System, Section 6, Extreme System Conditions Assessment.
[29] Data Request STAFF 4-26.
[30] Data Request TS-8.

between the 2009 UES load forecast used in the Kingston analysis and its most recent 2010 load forecast.

UES 2009 and 2010 Load Forecast Comparison

	2009 Load Forecast(1)		2010 Load Forecast(2)	
Year	**Peak Design Forecast (MW)**	**Extreme Peak Forecast (MW)**	**Peak Design Forecast (MW)**	**Extreme Peak Forecast (MW)**
2010	**[BEGIN CONFIDENTIAL]** [redacted]	**[BEGIN CONFIDENTIAL]** [redacted]	-	-
2012	[redacted]	[redacted]	181	186
2015	[redacted] **[END CONFIDENTIAL]**	[redacted] **[END CONFIDENTIAL]**	195	203
2017	-	-	204	212

1 – Data Request STAFF 1-31.
2 – Data Request TS-8.

It is apparent from the table that the most recent load forecast by UES extends the need date for the Kingston project by about two years under what Accion believes are conservative assumptions based on historic growth rates from 2010 without consideration for the current economic climate.

UES stated that they looked at a 345/34.5kV source in the area, a new 34.5kV line from Hampton and a 20 MW generator as alternatives to the Kingston project. The 34.5 kV line was dismissed because UES stated that it would have to be built as a double circuited line with one of the existing lines because of right-of-way width insufficiency and, if built to that configuration, reliability would suffer. Accion believes that there are construction configurations that would not have those attributes that UES did not examine as alternatives. UES dismissed the remaining alternatives because of cost.[31] Based its own experience, Accion would agree.

The original analysis performed by UES that justified the Kingston project was based on a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** overload in 2012.[32] The rating procedure assumes every day is like the peak day so the preloading of the transformer for thermal buildup is the peak day itself, which is a conservative assumption. In my opinion and experience, a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** overload for a 3-day heat wave of equal intensity would produce little detrimental effect to the transformer. UES did not request that PSNH evaluate this issue. The very small potential slight overload moves the installation date one year sooner than if a smaller overload was allowed. The issue is put into perspective when one considers that PSNH has an identical transformer that it uses as a system spare should the unit fail; I understand that replacement is usually accomplished within a week. Triggering a project that now is proposed to cost $23 million for a small overload, with a small potential of occurring, and is likely to cause little harm is a bad business decision. If PSNH were to take the position that an overload is an overload regardless of size, it would just be to force the investment benefits that I describe above.

[31] Data Request OCA 2-52.

[32] Data Request TS-6 shows that the rating of the transformer increases by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** when a load cycle matching the 90/10 load level is used.

Another inexpensive alternative to increase the rating of the existing Kingston transformer may be the addition of fans to the external cooling radiators. This was not investigated by UES.

In its response to Data Request OCA 3-18, UES stated that no rate mechanisms such as interruptible rates were evaluated for the Kingston project.

Q. What are your conclusions and recommendations regarding the inclusion of the Kingston project in the Large Capital Project step adjustment?

A. I conclude that the Kingston project should not be included in the Large Capital Project step adjustment under consideration for this case, as its need date is significantly beyond 2012 and outside of the short term view of the step adjustment mechanism for the reasons stated above. I also note that in a very recent supplemental filing, UES states that the project can be delayed by one year until 2013 because of a reduced load forecast,[33] a disagreement with PSNH resulting in project schedule slippage, and that the project was behind schedule on its own merits. I note that UES disagrees with its own load forecast which indicates that the project can slip two years on that basis alone. I also note that the project at its latest projected cost would allow UES to spend $700,000 a year to defer the project,[34] and that such expenditures would be neutral from a customer viewpoint. Any amounts under that value would actually represent savings to customers.

[33] UES Supplemental Data Request STAFF 1-31 Sup. In addition, UES response to Data Request STAFF 4-34 states that the current economic conditions are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

I recommend that UES be required to investigate alternative transmission configurations for the Kingston project, evaluate additional cooling for the transformer, revaluate previous alternatives because project costs have increased, include current economic consideration into its short-term load forecast, and investigate the application of rate mechanisms to defer the project, if reasonable to do so. Many of these items should also be revisited in total in the focused engineering and operations audit that I recommend below.

Q. You have mentioned a focused engineering and operations audit on several occasions. Please describe what you are recommending and the reasoning for such an audit.

A. I am recommending that as part of its decision in this rate case the Commission require that UES undergo a Commission-directed/sponsored audit focused on the Company's engineering and operations practices, procedures, and policies. I would expect that the audit would be positive in nature and embraced by UES as an opportunity to improve its business and make it more efficient. I also recommend that the Commission require the inclusion of a follow up component of the audit, so that the audit continues for sufficient duration to ensure that the recommendations are, in fact, implemented. Many times, recommendations are not carried out because personnel requirements are changed due to retirements, promotions, terminations, and management succession activities.

[34] The approximate first year revenue requirements of the project.

Let me cite my reasoning for my audit recommendation taken from the review performed in this docket:

- UES failed to recognize that the differentiation of tree trimming by 3 phase and single phase voltage resulted in concentrating outages to a specific group of customers, and considered the decision from a financial perspective only, without consideration for system reliability;
- Reliability projects were treated as discretionary by UES rather than part of normal business;
- I believe that the inspection process can be improved;
- During a technical conference, discussions with UES indicated that circuit taps were not being fused, that when fused, the fuses were not optimally located to separate customer problems from the main line, and that UES construction methods may not be meeting NESC requirements;
- The proposed VMP is based on a logic that will decrease power quality to customers, decrease safety to customers; and cause damage to the distribution system;
- The UES System Planning requirements are overly conservative; and
- The short term load forecast lacks economic or econometric data.

All of these issues suggest that opportunities for improvement exist across a wide range of issues. From discussion in this docket, I believe that the audit performed by the Commission regarding restoration after the recent severe weather events provided numerous opportunities for improvement and that UES has seized the opportunity to improve its business. The intent of my recommendations is to achieve similar improvements.

Q. Are there other issues that you wish to testify to today?

A. Yes, there is one and it will augment the testimony of Mr. Mullen. We spoke of restoration discussions directly above. One of the UES proposals in this case is that pre-staging resource costs be recovered as part of a Major Storm Reserve Fund if a major storm does not materialize. UES proposes that if a PDI[35] level of 2 is forecasted at a high level of probability[36], that storm preparation and pre-staging would take place and their costs would be recovered through the Major Storm Reserve Fund.

UES has analyzed the damage associated with the PDI values and equated them to storms that are considered Major Storms by the Commission. UES found the storms in the high end of the PDI level 2 can cause significant system problems and can escalate to a higher PDI level.[37] I concur that UES has proposed a storm center activation point that closely matches what the Commission considers to be a Major Storm, and that the PDI level choice appears to be reasonable. I recommend that it be adopted by the Commission. In addition, the selection of a defined point in the PDI level negates the need for determining the appropriateness of storm center activation after the fact, saving both UES and regulatory time. This docket does not include review of the PSNH Emergency Response Plan, which I would expect includes standards for when the storm center activities are activated.

[35] Potential Damage Index. The index varies from 0 to 4 and potential damage increases as the index increases.
[36] Greater than 60% according to Data Request STAFF 4-51.
[37] Data Request STAFF 3-71.

Q. Are there any other items you wish to discuss?

A. Yes, I would like to list here the data responses relied upon by Accion in preparation of its testimony in addition to the materials filed by UES so they may be officially admitted into the record. Those data responses are:

Staff Set 01

Data Responses 25, 26, 29, 31, 31-Sup, and 32.

Staff Set 03

Data Responses 27, 30, 51, 59, 67, 71, 75, 77, and 78.

Staff Set 04

Data Responses 26, 34, 45, 46, 50, and 51.

OCA Set 02

Data Responses 52 and 53.

OCA Set 03

Data Responses 2 and 18.

TECH Set 01

Data Responses 5 through 8, 11, and 13.

Q. Does that conclude your testimony?

A. Yes, it does.