STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 10-055

Unitil Energy Systems, Inc.
Petition for Approval of Base Rate Increase

DIRECT TESTIMONY

OF

GEORGE R. McCLUSKEY

November 5, 2010

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is George McCluskey, and my business address is the New Hampshire Public Utilities Commission ("Commission"), 21 South Fruit Street, Suite 10, Concord, NH 03301.

Q. What is your position with the Commission?

A. I am an analyst within the Electricity Division.

Q. Please describe your background and experience.

A. I am a utility ratemaking specialist with over 30 years experience in utility economics. I rejoined the Commission in March 2005 after working as an energy consultant for La Capra Associates for five years. Before joining La Capra Associates, I directed the Commission's electric utility restructuring division and before that I was manager of least cost planning, directing and supervising the review and implementation of electric utility least cost plans and demand-side management programs. I have participated in restructuring-related activities in New Hampshire, Arkansas, Pennsylvania, California and Ohio and have presented or filed testimony before state regulatory authorities in New Hampshire, Maine, Ohio and Arkansas and before the FERC. I have also testified on a variety of cost-of-service and rate design topics. A copy of my resume is included as Exhibit GRM-1.

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

A. My testimony will address a number of issues raised in the testimony filed on behalf of Unitil Energy Systems, Inc. (UES or Company) by James Normand of Management Applications Consulting (MAC). Those issues relate to the key components of Mr. Normand's testimony; namely, his marginal cost-of-service study (COSS) and his proposed distribution rates.

Q. What purpose does the marginal cost-of-service study serve?

A. The results of the marginal COSS were used first to establish the distribution revenue requirement for each rate class then to design proposed rates for those classes.

Q. Please define the term marginal cost and distinguish from the term average cost or average accounting cost.

A. Average cost or average accounting cost (also known as average embedded cost) refers to the accounting costs reflected on a utility's books. Average distribution cost is the total accounting cost to deliver a given quantity of electricity to customers, divided by the total number of units delivered. Marginal cost is the change in total cost of delivery attributable to a small change in output. Unlike average cost, marginal cost is not influenced by fixed or sunk costs. Marginal cost reflects only variable costs.

Q. How is the remainder of your testimony organized?

A. In Section II, I address the Commission's policy on the development of class revenue requirements. In Section III, I provide a brief discussion of investment in electric distribution systems. This discussion provides a framework for my assessment of Mr. Normand's marginal COSS in Section IV. This is followed in

Sections V and VI with a critique of Mr. Normand's proposed class revenue requirements and rate design changes, respectively.

Q. Before you begin your critique of Mr. Normand's marginal cost study, please summarize your conclusions and recommendations in this proceeding.

A. My conclusions are summarized as follows:

1. Mr. Normand's marginal cost-based charges would bring in approximately 30% less revenue than UES' proposed distribution revenue requirement.
2. After adjusting the marginal cost-based charges to collect the shortfall, the marginal COSS indicates that the residential, small C&I and outdoor lighting classes are being subsidized by the large C&I class.
3. Elimination of these subsidies would require increases ranging from 11% to 55%, relative to present rates, for the subsidized classes and a reduction of 12% for the large C&I class.
4. For rate stability reasons, Mr. Normand has proposed increases for all classes ranging from 15% to 37%.
5. The principal component of Mr. Normand's marginal COSS, the capacity cost of primary distribution, was calculated using a methodology that leaves little confidence in the accuracy of the result.
6. On the issue of rate design, Mr. Normand has proposed to increase customer charges for residential and small C&I customers by

approximately 50%, decrease customer charges for large C&I (secondary) customers by approximately 9%, and increase customer charges for large C&I (primary) customers by approximately 5%.

My recommendations are summarized as follows:

1. Based on the assumption that the proposed distribution revenue requirement is approved, all rate classes should receive an increase in revenue requirements. The residential classes should be increased 37%; the small C&I classes 31.4%; the large C&I classes 4.2%; and the outdoor lighting classes 29.7%.
2. The monthly customer charges for the residential and small C&I classes should increase by 37% and 50% respectively. The monthly customer charges for the large C&I classes should be decreased by 20%.
3. UES' Midnight Outdoor Lighting Service Option should be approved as filed.
4. Finally, the Company should implement the methodological changes to its marginal COSS described in Section IV of this testimony.

II. COMMISSION POLICY ON THE DEVELOPMENT OF CLASS REVENUE REQUIREMENTS

Q. You note above that Mr. Normand's class revenue requirements are based on the results of a marginal cost study, which he justifies by claiming that the Commission has traditionally relied on such studies for determining class revenue requirements. Do you agree?

A. Yes and no. Mr. Normand's claim is correct as it relates to base rate cases for natural gas companies. In 2000, both Northern Utilities and EnergyNorth Natural Gas filed base rate cases in which the class revenue requirement targets were based on the results of marginal cost of service studies. However, the standard practice with regard to electric utilities is less clear. While PSNH's class revenue requirements in its 2003, 2006 and 2009 distribution base rate cases (Docket Nos. DE 03-200, DE 06-028 and DE 09-035) were developed based on the results of embedded COSS, UES based its class revenue requirements in its 2002 and 2005 base rate cases (Dockets DE 01-247 and DE 05-178) on marginal COSS.

Q. What do you conclude from these facts?

A. I conclude that the Commission does not currently have a definitive policy on the development of class revenue requirements for electric utilities and, therefore, it is reasonable for Mr. Normand to propose a marginal COSS for this purpose. I also believe that by basing rates on marginal cost it is possible to simultaneously pursue the three public policy goals most often attributed to sound ratemaking, namely: efficiency, adequacy and equity.[1]

III. DISTRIBUTION SYSTEM INVESTMENT

Q. Please provide a brief overview of the UES distribution system.

A. UES operates two distribution systems, one located in the Seacoast area of New Hampshire and the other in the Concord area. The two systems are not physically connected at the distribution system level. The Seacoast distribution system is supplied from substations connected to PSNH's 345 kV and 115 kV transmission systems. The Concord distribution system is supplied from the Northeast Utilities-PSNH 34.5 kV sub-transmission system at various delivery points.

Within each area, UES' distribution system comprises a number of sub-systems that operate at different voltage levels. Sub-transmission is a term used to designate the circuits which deliver energy to distribution substations. UES' sub-transmission system is operated at 34.5kV and is configured as a network to deliver bulk power throughout an operating area. Accordingly, the sub-transmission system serves loads from all customer classes. The substations fed by the sub-transmission system in turn feed the 13.8kV and 4kV primary distribution system lines. A single substation will typically serve several primary circuits. In addition, the sub-transmission system feeds 34.5kV radial lines that supply power to primary distribution lines via step down transformers or directly

[1] Accounting cost studies can also satisfy the adequacy goal, but they are often found to be deficient when it comes to the other policy goals.

to customers at secondary voltages via line transformers. The secondary system serves most of the customers at 120/240 volts. Power fed to primary distribution lines is subsequently transformed to secondary voltages by line transformers.[2] A customer that receives service at secondary voltages is typically supplied via a service line connected to a line transformer.

Q. Which factors drive investment in sub-transmission?

A. The expansion of UES' 34.5kV sub-transmission system, plus the substations connecting that system to the 34.5 kV radial and primary distribution lines, is driven by the maximum load on those facilities, which occurs at or close to the time of the coincident peak demand of the entire system.[3] Coincident peak demand is the term used to describe the load on a system during the hour of maximum demand. The coincident peak demand of UES' entire system occurs when the combination of UES' commercial, industrial, and residential loads places the greatest total demand on the system. Because the maximum loads on the 34.5kV sub-transmission system and the connecting substations occur at approximately the same time as the coincident peak demand, the investment in these facilities is driven by growth in coincident peak demand.

Q. What does this mean for cost allocation?

A. To the extent that investment in UES' 34.5kV sub-transmission system and connecting substations is driven by growth in coincident peak demand, the

[2] Some customers are supplied directly from the primary system.
[3] The terms load and demand are used interchangeably for purposes of this testimony.

principle of cost causation would suggest that the costs associated with these facilities be allocated to the classes based on class contributions to coincident system peak.

Q. Before you address investment in the remaining parts of UES' distribution system, please discuss the concept of diversity.

A. It is well known that commercial, industrial, and residential customers have different consumption characteristics and, hence, different load shapes. As a result, the maximum demands for these customer classes typically occur at different times. Because of this fact, the coincident peak demand on UES' sub-transmission system, which serves all three customer classes, is invariably smaller than the sum of the class maximum demands. This phenomenon is known as diversity. Absent diversity between the different class loads, expansion of the 34.5kV sub-transmission system and the connecting substations would be more costly because the system components would have to be sized to serve the sum of the class maximum demands.

Q. Does diversity, or the lack of it, play a role in determining the drivers of investment in 34.5 kV radial and primary distribution lines?

A. Yes, it does. As noted above, a single substation typically feeds several 34.5kV radial or primary lines, which in turn supply customer load either directly or via transformation to secondary voltages. The maximum load on an individual radial or primary line will, therefore, reflect the loads connected to it. Since the number of individual customers supplied by each line will obviously be lower than the number supplied by the sub-transmission system and each line is unlikely to serve customers from all three customer classes, the loads on a typical 34.5kV radial or primary line will be less diverse than the loads served by substations. Thus, the maximum demand on each line is unlikely to be coincident with the maximum demand on the sub-transmission system. For this reason, investment in those facilities should be allocated to the various rate classes based on class contributions to non-coincident peak demand, the driver of those investments.

Q. Does Mr. Normand agree?

A. Yes.

Q. What are the revenue requirement implications of this fact?

A. Since class contributions to non-coincident peak demand at the primary level are likely to be different from class contributions to system coincident peak demand, some classes will benefit from the use of the different allocator and some will suffer. For example, if residential customers contribute more in percentage terms to the non-coincident peak demand than to the coincident peak demand, those customers will be allocated a larger share of the 34.5 kV radial and primary investment cost if a non-coincident demand allocator is used instead of a coincident demand allocator.

Q. What conclusion did Mr. Normand reach regarding investment in line transformers and services?

A. The loads on distribution facilities nearer the customer, such as line transformers and services, reflect even lower diversity than do the loads served by radial and primary lines. Accordingly, these facilities are sized to serve the expected maximum demands of connected customers. For this reason, Mr. Normand concluded that investments in line transformers and services should be allocated based on the sum of individual customer maximum demands.

Q. What conclusion did Mr. Normand reach regarding investment in secondary distribution lines?

A. Mr. Normand concluded that investment in secondary lines is driven by the non-coincident peak demands on those lines.

Q. Do you agree with these conclusions?

A. Yes.

IV. MARGINAL COST OF SERVICE STUDY

Q. Please provide a brief overview of Mr. Normand's marginal cost study.

A. The assignment of UES' proposed distribution revenue requirement to customer rate classes is based on the results of Mr. Normand's marginal COSS. A properly constructed marginal cost study seeks to estimate the costs of providing one additional or one less unit of service, which in the case of distribution service comprise capacity-related and customer-related costs. Once estimated, these unit costs would be multiplied by the corresponding billing determinants for each rate class to arrive at the marginal cost-based class revenues. To the extent the sum of these marginal cost-based class revenues differs from UES' proposed distribution revenue requirement, the marginal cost-based class revenues would be adjusted up or down to provide UES an opportunity to recover its revenue requirement.

Mr. Normand's marginal COSS provides marginal capacity cost estimates for each component of UES' distribution system including the marginal cost of operations and maintenance. He also provides estimates of the marginal cost of adding to the system a single customer in each rate class.

Based on these cost estimates and the corresponding class billing determinants, Mr. Normand estimated that marginal cost based charges would bring in 29.57% less revenue than UES' proposed distribution revenue requirement of $44,293,324.[4] In order to recover this shortfall, Mr. Normand increased the marginal class revenue requirements uniformly, subject to the constraint that no single class receive an increase in revenue requirement that exceeds the proposed overall average increase by more than 125%. That is, the maximum amount any class' revenue requirement could be increased is approximately 37% based on a proposed overall increase in revenues of 29.55%

[4] See Exhibit GRM 2.

Q. Do you have any concerns with the methodology used to develop the marginal cost based class revenue requirements?

A. Yes, I have several concerns. For example, the methodology used to estimate the marginal cost of primary distribution capacity is not based on forward looking projections of primary system load growth and related distribution investments. Rather, that cost estimate was developed using historical data. Specifically, growth-related capital additions over an eighteen-year historical period were identified and regressed against growth in system coincident peak demand over the same time period. While it is common to use methods that employ historical data as proxies for the more complex forward looking marginal cost analysis, the reasonableness of the results depends critically on the quality of the available cost and load data.

My concern with Mr. Normand's calculation relates to his use of forecasted peak load data in the regression analysis as opposed to actual load data – a method he states produces a better statistical result than using actual peak loads. This explanation reveals that Mr. Normand is more concerned with obtaining good statistical results than obtaining accurate marginal cost estimates. The use of regression analysis to estimate marginal cost necessarily introduces a degree of error into the estimate. Replacing actual loads with forecasted loads in the proxy calculation simply adds to the error.

Q. What do you recommend?

A. Given that the marginal cost of primary distribution capacity accounts for a significant percentage of total marginal costs, I believe it is vital that the Company use, in the future, a different and more accurate approach to estimating this cost. I recommend that the marginal capacity cost of primary distribution be determined based on projected reinforcement costs to supply additional peak period demand at a select number of locations. If these reinforcement projects are spread out over time, then the reinforcement cost estimates must be present valued.

Q. Do you have other concerns with Mr. Normand's calculation of marginal capacity costs?

A. Yes. After calculating the marginal capacity costs for primary, secondary and line transformer investments, Mr. Normand then multiplied each cost by a fixed charge rate that determines the levelized annual charge that collects UES' investment and related return over the life of the distribution asset. These calculations are summarized in Table 9, page 1 of his schedules. Similar calculations were performed by Mr. Normand to determine the levelized annual charges that collect the investment and return for services and meters. These calculations are summarized in Table 11, page 1. For each investment, whether distribution, services or meter related, Mr. Normand used what he calls the Economist's Fixed Charge Rate to determine the levelized annual charge. The Economist's Fixed Charge Rates for investments in distribution, services and meters are summarized in Table 8, page 1 along with what he calls the Engineer's Fixed Charge Rates. Although Mr. Normand explains in detail how he derived the Engineer's Fixed Charge Rates he provides no support for the Economist's Fixed Charge Rates. As a result, I am unable to determine how the two types of rates differ conceptually.

Q. Is it your opinion that the engineer's fixed charge rate produces an accurate estimate of marginal cost?

A. Yes. The Engineer's Fixed Charge Rates for distribution, services and meters were developed by Mr. Normand in Table 8, pages 8-10 respectively. After making several adjustments to those tables, I believe the resulting fixed charge rates produce reasonable marginal cost estimates.

Q. What adjustments did you make?

A. The primary difference between my development of the fixed charge rates and Mr. Normand's is the inclusion of salvage in Mr. Normand's calculations. Salvage is not a cost that is driven by incremental demand growth and therefore is not marginal. Other smaller differences include Mr. Normand's use of year end investment balance rather than average balance to calculate the return on investment. In addition, Mr. Normand assumed no accelerated depreciation for meters. In my opinion, a 10 year tax depreciation schedule for meters is appropriate. After making these changes and using the cost of capital recommended by Staff's witness in the case, I estimate the fixed charge rates for distribution, services, and meters to be 12.27%, 12.03%, and 12.47% respectively.[5] These rates differ from the 9.77% and 10.72%, and 12.17% rates used by Mr. Normand.

Q. The fixed charge rates for services and meters were used in the development of marginal customer costs. Do you have other concerns with the calculation of marginal costs?

A. Yes, I have several. The calculation of marginal customer costs by class is set forth in his Table 11 at page 1. Although I believe the results of this calculation, which were used by Mr. Normand to inform his recommendation regarding new customer charges, overstate marginal customer costs, the difference is not large enough to merit a different set of cost-based customer charges.[6] That said, a number of adjustments to the methodology are need. First, the 6.58% general plant loading factor in Table 11 should be changed to 5.58%, the loading factor in the referenced source. Second, the fixed charge rates for services and meters should be changed as discussed above. Third, the working capital rate of 12.33%, which is based on an assumed 45 days net lag, is unreasonably high. A better proxy is the 3.86% rate calculated by Mr. Normand in National Grid's distribution rate case, Docket No. DG 10-117, using a lead-lag study. Fourth, the escalator to adjust costs to 2011 should be eliminated because marginal costs should be expressed in test year dollars. Finally, I used the before tax cost of capital

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[5] See Exhibit GRM-3, pages 1-3.
[6] I do, however, recommend different customers charges based on non-cost grounds.

recommended by Staff's witness to calculate the working capital revenue requirement. The results are shown in Exhibit GRM-4.

Q. Do you have other concerns with the calculation of marginal cost?

A. Yes, Mr. Normand's Table 12 provides a summary of long run marginal cost by cost component (i.e., customer- and demand-related costs) and by rate class. The table shows that each cost component for each rate class has been adjusted upwards by a factor that represents the class uncollectable percentage – that is, the percentage of customer non-payments. Such adjustments, however, are inappropriate because the cost of customer non-payment is not a marginal cost. The cost to meet growth in demand, or to add a new customer to the system, is independent of whether that customer pays his or her bill on time or at all. Indeed, customer non-payment is a revenue collection issue and not a marginal cost issue. For this reason, I recommend that all adjustments for uncollectable costs be removed.

V. DERIVATION OF CLASS REVENUE REQUIREMENTS

Q. Please explain how the class revenue requirements were derived.

A. As noted above, Mr. Normand's marginal cost-based charges bring in 29.57% less revenue than UES' proposed distribution revenue requirement.[7] In order to address this shortfall, he increased the marginal class revenue requirements uniformly, subject to the constraint that no single rate class receive an increase in revenue requirement that exceeds the proposed overall average increase by more

[7] See Exhibit GRM-2.

than 125%. That is, the maximum amount any class's revenue requirement could be increased is approximately 37% based on a proposed overall average increase in revenues of 29.55%.

Q. What does the uncapped marginal COSS show?

A. As shown in Exhibit GRM-2, in the middle of the exhibit, the principal conclusion of Mr. Normand's marginal COSS is that the residential, small C&I and outdoor lighting classes are being heavily subsidized by the large C&I class. To eliminate these subsidies, Mr. Normand would have to propose increases for the subsidized classes ranging from 11% to 55%, relative to present rates, and a reduction of 12% for the large C&I class.

Q. Did Mr. Normand propose changes in class revenue requirements to eliminate the subsidies?

A. Not completely. As indicated above, for rate stability reasons he capped the increase that any class could receive to 125% of the overall average increase. This resulted in the under-collection of the adjusted marginal revenue requirement for the residential class that, in turn, had to be collected from other classes.[8] Mr. Normand proposed to allocate the residential revenue shortfall among the small C&I and large C&I classes based on each class's kWh consumption.

[8] See Exhibit GRM-2.

Q. What are the proposed increases in class revenue requirements?

A. Mr. Normand proposed increases of 37% for the residential classes, 25.5% for the small C&I classes, 15.26% for the large C&I classes, and 29.7% for the outdoor lighting classes.

Q. Do you agree with that proposal?

A. No, I do not. The allocation of the revenue shortfall between the small C&I and large C&I classes should be based on class marginal costs rather than class kWhs. That is, the class with the higher marginal costs should be allocated proportionately more of the shortfall. Using this allocation method, I recommend the following class increases: 37% for residential, 31.4% for small C&I, 4.2% for large C&I , and 29.7% for outdoor lighting.

VI. RATE DESIGN

Q. Have you reviewed UES' proposed rate design in this case?

A. Yes. Mr. Normand's rate design proposals include:

- Increasing customer charges for residential and small C&I customers by approximately 50%, decreasing the customer charge for large C&I (secondary) customers by approximately 9%, and increasing the customer charge for large C&I (primary) customers by approximately 5%.
- Collecting (returning) any shortfall (excess) of class revenue requirements through an increase (decrease) in the energy (kWh) charge.

- Adjusting all fixed rate components of outdoor lighting rates by an equal percentage.

Q. Please describe the existing rate structure for residential customers.

A. Most residential customers receive distribution service under Rate D, which comprises a monthly customer charge and an inclining block energy rate. That is, an initial block of kWhs each month is provided at a rate that is lower than the rate applied to all kWh consumed in excess of that amount. This rate structure is commonly referred to as a lifeline rate and its chief social purpose is to provide a minimum amount of utility service at a discounted price to those who would otherwise not be able to afford it. Customers are also encouraged to conserve energy through this rate structure.

Q. How has Mr. Normand proposed to modify the design of residential rate d?

A. Because marginal customer costs were found to be substantially higher than the existing customer charge for residential customers,[9] he proposed to raise the customer charge by about 50%. To collect the resulting revenue requirement shortfall, he has proposed to increase the initial block and tail block energy rates by 35% and 27.4%, respectively.

[9] See Exhibit GRM-3.

Q. The increase in the customer charge has been justified on cost grounds. What is the justification for increasing the energy rates?

A. Mr. Normand believes that distribution capacity costs are independent of energy consumed by customers and, therefore, more appropriately recovered through fixed or demand charges. However, because a large increase in the customer charge can place a significant cost burden on low-use customers, Mr. Normand opted for a smaller customer charge that under-collects the proposed class revenue requirement. As a result, the shortfall must be collected through increases in the energy rates.

Q. Do you have any comments on Mr. Normand's rate D proposal?

A. Yes, I do. Leaving aside our differences on class revenue targets, I believe it is reasonable to collect the new class revenue requirement through increases in both customer and energy charges. However, I believe the proposed increase in the customer charge is too great. In order to further reduce the burden on low-use customers, I recommend a smaller increase in the customer charge and a larger increase in the energy rates. Under Mr. Normand's proposal, low-use residential customers (0-300 kWh per month) would receive bill increases ranging from 14 to 32% on a total bill basis. This compares with increases of 5 to 6% for large use customers. Since it is not reasonable to require low-use customers to shoulder a significantly higher share of the increased cost burden than all other residential customers, I recommend that the monthly customer charge be increased by no more than 37%, from $8.40 to $11.50.

Q. Do you support UES' rate design proposal for small C&I customers?

A. Yes, I do. Because current customer charges are so far below marginal cost, even a 50% increase would still leave a significant portion of the customer cost to be collected through usage rates.

Q. Do you support the large C&I rate design proposal?

A. No. The proposal to increase the customer charge for large C&I (primary) customers by approximately 5% is not supported by my estimate of marginal customer costs.[10] In addition, the proposal to decrease the customer charge for large C&I (secondary) customers by approximately 9% will do little to close the large gap between the current charge and marginal cost. I recommend that both customer charges be reduced by 20%.

Q. The company has included a midnight outdoor lighting service option in its proposed outdoor lighting tariff. What is this option?

A. The midnight option employs a time clock photocell to turn the outdoor light on or off at specified times whereas the more common all-night option is limited to turning the light on at dusk and off at dawn using a simple light sensitive photocell.

Q. Does staff support this proposal?

A. Yes.

[10] See Exhibit GRM-4.

Q. Does staff also support the proposed rates for the midnight option?

A. Staff supports the proposed rate design, which includes separate charges to recover the cost of distribution service and the incremental costs to purchase and install the additional equipment.

Q. Does that conclude your testimony?

A. Yes.