# STATE OF NEWHAMPSHIRE

# PUBLIC UTILITIES COMMISSION

**DE 10-261** REDACTED

**In the Matter of:**
**Public Service Company of New Hampshire**
**Least Cost Integrated Resource Plan**

**Direct Testimony**

**of**

**George R. McCluskey &**
**Edward C. Arnold**

**July 27, 2011** (REDACTION FORMAT UPDATED 9/8/11)

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**STATE OF NEW HAMPSHIRE**
**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**

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# DIRECT TESTIMONY OF GEORGE R. McCLUSKEY & EDWARD C. ARNOLD

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.**

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.

My name is Edward Arnold and my business address is Jacobs Consultancy, Inc. ("Jacobs"), 525 West Monroe, Suite 1350, Chicago, Illinois, 60661.

Q. **MR. McCLUSKEY, WHAT IS YOUR POSITION WITH THE COMMISSION?**

A. I am an analyst with the Electric Division.

Q. **MR. ARNOLD, WHAT IS YOUR POSITION WITH JACOBS CONSULTANCY?**

A. I am a group manager in the refinery/fuels division.

Q. **MR. McCLUSKEY, 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, rate design and power procurement topics. A copy of my resume is included as Staff Exhibit-1.

Q. **MR. ARNOLD, PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.**

A. A copy of my resume is included as Staff Exhibit-2.

Q. **MR. McCLUSKEY, WHAT IS THE PURPOSE OF THE JOINT TESTIMONY FILED IN THIS PROCEEDING?**

A. The joint testimony addresses two issues raised in the 2010 Least Cost Integrated Resource Plan (2010 IRP) filed by Public Service Company of New Hampshire (PSNH or Company) with the Commission on September 30, 2010. The first, which relates to the reasonableness of PSNH's demand-side resource planning, is presented by me alone. The second relates to the Continuing Unit Operations (CUO) Study for Newington Station prepared for PSNH by Levitan & Associates,

Inc. (LAI), a management consulting firm that specializes in the energy industry. Newington Station is one of PSNH's three fossil-fired generating facilities. Issues relating to the CUO Study are addressed jointly by Mr. Arnold and myself.

Q. **HOW IS THE TESTIMONY ORGANIZED?**

A. In Section II, Mr. Arnold and I review and analyze the CUO Study prepared by LAI on PSNH's behalf. This is followed in Section III with a review and evaluation of PSNH's demand-side assessment with a particular focus on the GDS energy efficiency potential study and its application to PSNH's service territory.

## II NEWINGTON STATION CONTINUING UNIT OPERATIONS (CUO) STUDY

### A. Background

**Q. WHAT IS THE BACKGROUND TO THE INCLUSION OF THE CUO STUDY IN PSNH'S 2010 LCIRP?**

A. Newington Station is an oil-fired generating unit that is capable of burning natural gas. It began commercial operation in 1974. The unit has the flexibility to vary its output within the range 60 MW to 400 MW. The maximum output can be achieved only using residual fuel oil (RFO). When firing on natural gas only, Newington can produce 320 MW. When firing a combination of natural gas and oil, Newington can produce 360 MW. The unit was designed for fast response and startup, historically making it attractive for both intermediate and peaking duty. In recent years, the unit has been used almost exclusively to meet peak demands.

The issue of Newington's continued operation was first raised in testimony filed by Staff in Docket DE 09-180, the proceeding to address PSNH's proposed 2010 Energy Service rate. In that proceeding, Staff noted that " Newington Station has become increasingly uneconomic and, as a result, its capacity factor has steadily declined from 55.9% in 2003 to 3.3% in 2008" and that "as the capacity [factor] of the unit decreased, the revenues associated with the plant have been exceeded by the plant-related expenses." Order No. 25,061 at page 17.

Based on these conclusions, Staff stated the opinion that "it is time to review the continued operation of Newington Station." Ibid. Specifically, Staff recommended that "PSNH prepare a study regarding the benefits and costs of [PSNH's] continued ownership and/or operation of Newington Station and whether the plant will continue to provide benefits to PSNH customers." Order No. 25,061 at page 18. Additionally, Staff stated that "the study could be filed as part of PSNH's next LCIRP, as part of the Docket DE 09-180, or independently." Ibid.

In response to Staff's recommendation, the Commission stated that it "agree[d] with Staff that the Company should conduct a study of the costs of continuing the ownership and operation of the plant" and that the study be "incorporate[d] … in the LCIRP to be filed no later than September 30, 2010." Order No. 25,061 at page 31.

**Q. HOW DO YOU INTERPRET THE COMMISSION'S DECISION?**

A. Since the Commission stated in its order that it agreed with Staff, we think it is reasonable to assume for the purposes of understanding the scope of the Company's investigation that the specifics of Staff's recommendation govern. As noted, Staff recommended that "PSNH prepare a study regarding the benefits and costs of [PSNH's] continued ownership and/or operation of Newington Station and whether the plant will continue to provide benefits to PSNH customers." While the phrase "continued ownership and/or operation" can be construed in many ways, we believe the Staff and hence the Commission intended that PSNH compare the benefits to customers of continuing to operate the plant with the benefits to customers of retirement. Staff's recommendation did not go as far requiring the costs and benefits of divestiture.

**Q. YOU SAID IN THE INTRODUCTION THAT LAI PREPARED THE STUDY ON PSNH'S BEHALF. DOES LAI'S STUDY COMPARE THE BENEFITS OF CONTINUED OPERATION TO THE BENEFITS OF RETIREMENT?**

A. LAI alleges that it does.[1]

[1] Sept. 29, 2010 CUO Study at page 1.

**Q. LAI STATES IN THE EXECUTIVE SUMMARY TO THE CUO STUDY THAT THE CENTRAL QUESTION TO BE ANSWERED IS WHETHER OR NOT THE ONGOING VALUE ASCRIBABLE TO PSNH'S CONTINUED OWNERSHIP AND OPERATION OF NEWINGTON STATION IS GREATER THAN THE COSTS BORNE BY ITS CUSTOMERS. DO YOU AGREE THAT THIS IS THE APPROPRIATE STANDARD FOR THE CUO STUDY?**

A. Staff agrees with the standard but opposes LAI's definition of the phrase "costs borne by its customers." Because LAI believes customers must pay the depreciation on past plant investments plus a return on the unrecovered balance of those investments whether or not the plant continues to operate, it assets that a decision to retire Newington should be based solely on a comparison of the incremental costs and benefits of operating the plant in the future.[2] We disagree with this assertion for the reasons set forth later in this testimony.

**B. Summary of CUO Study**

**Q. PLEASE SUMMARIZE THE CUO STUDY.**

A. As previously noted, the CUO Study was conducted by LAI on PSNH's behalf. Instead of performing a cost/benefit analysis based on deterministic values of the future costs and benefits associated with continued ownership and operation of Newington, LAI elected to perform a much more complex analysis that takes into account uncertainties in key inputs and outputs including the market price of fuels consumed in the plant and the market prices of energy and capacity produced by

[2] These incremental costs and benefits are also referred to as going-forward costs and benefits.

the plant. The modeling of uncertain future fuel and emission allowance expenses and energy net revenues was conducted using a Real Option Valuation (ROV) analysis.

The starting point for the ROV analysis is a set of expected price forecasts for oil, natural gas, and emission allowances, and both Day-Ahead Market (DAM) and Real Time Market (RTM) energy prices over the analysis period 2011-2020. The expected fuel price forecasts were based on NYMEX futures for RFO, No. 2 Fuel Oil (2FO) and natural gas. The expected market energy price forecasts were based on NYMEX forward energy prices at the MassHub through 2015 followed by NYMEX natural gas futures for the remainder of the analysis period. Capacity prices under ISO-NE's Forward Capacity Market (FCM) were also simulated probabilistically, but not using the ROV method applied to energy prices.

**Q. HOW DID LAI MODEL THE ENERGY NET REVENUE FROM THE PLANT?**

A. Energy net revenues were modeled based on the assumption that the plant is dispatched when it is economic to do so. That is, when market-based revenues exceed fuel costs plus appropriate variable O&M costs including the cost of emission allowances. When this condition is met in the model, the plant is assumed to be providing ISO-NE with economic energy service. In practice, however, PSNH also provides ISO-NE with operating reserves, which can involve the plant being dispatched at times when variable costs exceed market revenues (i.e., uneconomic operation). LAI's modeling of energy net revenues at

Newington does not, therefore, reflect actual operations, a fact that can result in differences between actual and expected outputs.

**Q. PLEASE PROVIDE AN EXAMPLE OF HOW THE MODELING RESULTS CAN DIFFER FROM ACTUAL OPERATIONS?**

A. Later in this testimony we discuss the results of an analysis conducted by LAI at Staff's request to determine the accuracy of the model compared to actual plant performance, using 2010 as the benchmark. Among other things, the model estimated the average heat rate for the plant in 2010 at 11,230 Btu/kWh, significantly different from the actual average heat rate in that year of 13,500 Btu/kWh. The difference was attributed to the fact that in 2010 the plant was dispatched in some hours to provide operating reserves rather than economic energy, resulting in the consumption of more fuel per kWh generated.

**Q. DID YOU GAIN ACCESS TO LAI'S MODEL TO CONDUCT YOUR INVESTIGATION?**

A. Neither Staff nor Jacobs was given access to LAI's Newington Station asset valuation model. As a consequence, Jacobs could not perform in-depth testing of the actual sub-models.[3] LAI argued that its model is proprietary and cannot be made available to competitors such as Jacobs. In addition, LAI declined to provide Staff and Jacobs certain data used in the model on the ground that such data was provided as part of LAI's subscription service with Bloomberg LP,

[3] Instead, Jacobs' review was limited to: (a) reading LAI's description of the model structure in summary reports; (b) reviewing LAI's responses to questions issued on those reports; and (c) analyzing the results of model re-runs, made at the request of Staff and Jacobs, based on different inputs.

which prohibits distribution of the data to other persons.[4] Consequently, we were unable to verify the accuracy of the calculations performed by LAI using the Bloomberg data.

**Q. PLEASE DESCRIBE THE DATA AND CALCULATIONS THAT LAI DECLINED TO MAKE AVAILABLE.**

A. As noted, one of the primary fuels consumed by the plant is natural gas. In the model, the forecast of Newington's natural gas fuel expenses is based on a forecast of daily natural gas prices at the Dracut trading point, plus a premium that varies monthly. The daily price of natural gas at Dracut is itself based on two parts, a forecast of spot prices at the Henry Hub trading point and an adder to account for the basis differential between Henry Hub and Dracut. The forecast of Henry Hub prices are the NYMEX forward curve that settled on August 27, 2010. The basis adder used to calculate the Dracut price forecast was based on a historical relationship between Henry Hub and Dracut prices. Data provided by Bloomberg LP was used to determine this relationship. Because LAI declined to make the historical data available, Staff could not verify the accuracy of the estimated Dracut prices.

[4] PSNH responses to Staff 1-84 and 1-85 attached to this testimony as Staff Exhibit-3.

**Q. DID LAI DECLINE TO PROVIDE STAFF WITH OTHER DATA SUPPLIED BY BLOOMBERG?**

A. Yes. In order to develop price forecasts for RFO and 2FO, LAI used historical correlations between West Texas Intermediate (WTI) crude oil prices and RFO prices and between WTI prices and 2FO prices. LAI declined to provide the historical WTI, RFO and 2FO prices supplied by Bloomberg that form the basis of those correlations. In addition, it declined to provide the associated calculations. For these reasons, Staff was unable to verify the accuracy of these model inputs.

**Q. HOW HAS NEWINGTON PERFORMED FINANCIALLY IN RECENT YEARS?**

A. LAI reports in the CUO study that Newington's recent financial performance has not been good. Exhibit G.1 to the original study shows that Newington recorded losses on its regulatory books in each of the six years ending 2010.[5] These losses, which range from $4.1million to $20.7 million, were collected from PSNH retail customers through rates regulated by the Commission.[6]

**Q. HOW WERE THOSE LOSSES DETERMINED?**

A. The profit/loss resulting from Newington's operations is calculated as the difference between the revenues received each year from the sale of products in ISO-NE's wholesale power markets and the annual fixed and variable costs of

[5] The original study reported half-year data for 2010. The full-year data showed a net loss of $4.1 million. PSNH response to Staff 1-61 attached to this testimony as Staff Exhibit-4.
[6] Unlike most of its competitors, Newington continues to be regulated by the Commission.

owning and operating the plant. The variable costs of operating the plant include fuel expense, non-fuel operations and maintenance (O&M) expense, and emissions allowance expense. The fixed costs of ownership include depreciation expense on plant investments plus a return on the unrecovered balance of those investments.

**Q. DID LAI REVISE EXHIBIT G.1?**

A. Yes. During the discovery process, PSNH reported that some of the 2007 gross plant amounts in Exhibit G.1 were incorrectly stated.[7] In addition, PSNH reported that the emissions allowance expenses for 2008 through 2010 and plant revenues for 2010 had been overstated.[8] After correcting these amounts, the resulting losses are as reported in Staff Exhibit-7.

**Q. WHAT DO YOU CONCLUDE FROM THESE RESULTS?**

A. The results indicate that for each of the six years ending 2010 customers have paid out more to PSNH to cover the costs of owning and operating the plant than they received from products sold in the wholesale power markets. Stated more succinctly, over this time period the costs incurred by customers have exceeded the benefits received. Accordingly, had the plant not been part of PSNH's generation fleet during this time period customers would have paid less for their power needs.

[7] PSNH response to Staff 1-56 attached to this testimony as Staff Exhibit-5.
[8] PSNH letter dated July 8, 2011 attached to this testimony as Staff Exhibit-6

**Q. DO THESE RESULTS MEAN THAT THE PLANT WILL BE UNECONOMIC IN THE FUTURE AND SHOULD BE RETIRED, IN THE VIEW OF LAI?**

A. No. As noted above, LAI believes that the depreciation and return on unrecovered past capital investments have no bearing on the retirement decision. Specifically, LAI accepts PSNH's contention that customers will incur those costs whether the plant continues to operate or not.[9] For this reason, it argues that any decision to retire the plant should be based on an economic comparison of the going-forward operating costs and revenues. If going-forward revenues exceed going-forward costs (even by a small amount) LAI believes the plant should continue to operate.

**Q. WHAT ARE GOING-FORWARD OPERATING COSTS AND REVENUES?**

A. Going-forward operating costs relate to the plant's future operations and comprise: (i) fuel and fuel-related O&M expenses; (ii) non-fuel O&M including labor and benefits costs, maintenance expenses, emission allowance expenses, and an allocation of PSNH's and NU's A&G expenses; (iii) property taxes; (iv) depreciation expense associated with new capital investments; and (v) a return on new, undepreciated capital investments, working capital, and inventories for fuel, emission allowances and M&S.

Going-forward revenues also relate to the plant's future operations and comprise: (i) energy-related revenue from the sale of MWh generated in ISO-NE's day-

[9] Sept. 29, 2010 CUO Study at page 17.

ahead and real-time energy markets; (ii) capacity-related revenue from Newington's participation in ISO-NE's forward capacity market; and (ii) ancillary services revenue from the provision of Automatic Generation Control (AGC), spinning reserves, and Volt Ampere Reactive (VARs).

**Q. DO YOU ACCEPT LAI'S REPRESENTATION OF THE APPROPRIATE ECONOMIC ANALYSIS FOR THE CUO STUDY?**

A. PSNH's assertion that the recovery of both depreciation and return on unrecovered past investments is guaranteed, even if the plant is retired because of economic obsolescence, effectively means that the Commission does not have the authority to modify cost recovery for investments that no longer provide benefits to customers. We disagree. The Commission, in our opinion, does have this authority and can, if it chooses, adjust the level of fixed cost recovery through rates. The adjustment could take many forms including reducing or eliminating the return on the unrecovered balance of past capital expenditures or reducing or eliminating depreciation expense.

It is also important to note that PSNH's assertion contradicts the FERC Uniform System of Accounts,[10] which states that when a plant is retired its book cost shall be credited to the electric plant account and charged to the accumulated provision for depreciation. For a plant that is not fully depreciated at the time of retirement, the net ratemaking effect of these two accounting entries is to eliminate the depreciation expense on the retired plant. If PSNH is unable to collect depreciation expense on a plant that is not fully depreciated at the time of its

[10] 18 CFR, Part 101, Electric Plant Instructions, 10

retirement, the retirement analysis must include this potential cost saving. This can be done by specifying the requirement for continued unit operation to be that the NPV of future margins[11] exceed the NPV of depreciation savings. As noted, LAI believes it is sufficient that future revenues exceed future expenses by the smallest amount. Thus, under LAI's formulation for continued unit operation, customers could end up paying significantly more to PSNH in the form of depreciation and return on rate base payments than customers receive in net margins.

**Q. WHAT ARE THE RESULTS OF LAI'S GOING-FORWARD ANALYSIS OF NEWINGTON'S OPERATIONS?**

A. As noted, LAI conducted a ROV analysis of Newington's operations that covered the ten year period 2011-2020 and involved, among other things, the modeling of 250 energy net revenue scenarios each year. In its original September 29, 2010 study, LAI estimated that the expected value of the 250 energy net revenue scenarios would range from a low of $14.6 million in 2012 to a high of $20.6 million in 2020. Over the ten-year analysis period, the Net Present Value (NPV) of the expected energy net revenues totaled $120 million.[12] In addition, LAI estimated ten-year streams of capacity revenues totaling $111 million and ancillary services revenues totaling $1.4 million, both expressed in present value terms. The sum of these incremental net revenue

[11] That is, the excess of future revenues over future expenses.
[12] Exhibit G.16 in Sept 29, 2010 CUO study.

streams less incremental expenses resulted in a total estimated NPV for the plant of $152 million.[13]

After identifying and correcting multiple errors in its modeling effort, LAI filed on April 26, 2011 revised expected values for the 250 energy net revenue scenarios. The revised range varies from a low of $ 4.4 million in 2012 to a high of $7.6 million in 2020. Over the ten-year analysis period, the revised NPV of expected energy net revenues totaled $39 million, a reduction of almost 70% compared to the original estimate.[14] Because the capacity and ancillary services revenue estimates were unchanged in the revised study, the total NPV for the plant was reduced by only 53% to $71.5 million.[15]

**Q. WHAT WERE THE MODELING ERRORS THAT CONTRIBUTED TO THE OVERESTIMATION OF ENERGY NET REVENUES?**

Q. There were three modeling errors. The first related to the function that translates daily spot gas prices into daily peak and off-peak energy prices. This problem resulted in spark spreads that were too small or too large as the stochastic gas prices moved farther above or below the initial forward prices. The second related to the incorrect implementation of the method for calculating historical hourly shaping factors to apply to the daily index energy prices. This error resulted in too much amplitude above and below the average price for each historical month. The third error related to the underestimation of plant heat

[13] Exhibit G.12 in Sept 29, 2010 CUO study.

[14] Exhibit G.16 in April 26, 2011 revised CUO study.
[15] Exhibit G.12 in April 26, 2011 revised CUO study.

rates. To correct the heat rates, LAI revised the model to linearly interpolate the heat rate table values for plant operation on oil and natural gas oil.

**Q. BEFORE YOU ADDRESS THE REASONABLENESS OF THE REVISED EXPECTED ENERGY NET REVENUE STREAM, PLEASE COMMENT ON LAI'S NPV CALCULATION.**

A. To calculate the NPV of the ten-year stream of energy net revenues, LAI used a discount rate of 7.586%. This rate is close to PSNH's after-tax weighted cost of capital (WACC), which in 2009 was estimated at 7.61%.[16] Staff believes it is reasonable to use the WACC to discount the net revenue stream.

**Q. THE APRIL 26, 2011 REVISION FILED BY PSNH TO CORRECT THE MODELING ERRORS RESULTED IN EXPECTED ENERGY NET REVENUES THAT RANGE FROM $4.5 MILLION IN 2011 TO $7.6 MILLION IN 2020. ARE THOSE REVISED ESTIMATES REASONABLE?**

A. There are two ways to evaluate the reasonableness of a complex model such as the one developed by LAI to estimate future financial performance. The best method is to show that it can reasonably "predict" past performance using backcasting analysis. The next best approach is to show that the model is "anchored" to the past by showing that the first year (or years) of the

[16] PSNH response to Staff 1-59 attached as Staff Exhibit-8.

model's forecast generates a result that is very close to the last year of history. Neither method of verification was employed by LAI in its study. Rather than accept LAI's assertion that the model can reasonably predict the plant's future performance, Staff requested that LAI conduct a backcasting analysis that involved re-running the model beginning 2010 instead of 2011 and comparing the estimated model results for 2010 to actual plant performance in that year.

**Q. WHAT CONCLUSION DID YOU DRAW FROM THE BACKCASTING ANALYSIS?**

A. We concluded that the model overstates Newington's future financial performance.

**Q. WHAT IS THE BASIS FOR THAT CONCLUSION?**

A. We based the conclusion on the fact that the energy net revenues estimated using the backcasting analysis exceeded actual 2010 energy net revenues by about 400% or almost $4.3 million. Although some of this difference was subsequently explained by two additional modeling errors found by LAI, a significant unexplained difference still remained.

**Q. WHAT ARE THE ADDITIONAL ERRORS AND HOW LARGE IS THE UNEXPLAINED DIFFERENCE?**

A. During the course of its investigation of the difference between estimated and actual 2010 plant performance, LAI concluded that it had understated the plant's start-up fuel costs and failed to include the cost of 2FO to keep the boiler from freezing during the winter months. Using higher start-up fuel costs and adjusting the model results for the cost of heating the plant during the winter months closed the net revenue gap between modeled and actual performance by about $1.6 million. In addition, LAI determined that the emissions allowance prices reflected in the 2010 cost data exceeded actual 2010 emissions allowance market prices. Replacing the former with the allowance prices included in the model closed the net revenue gap further by $1.5 million, leaving an unexplained difference of $1.2 million.[17] Thus, even after adjusting the results of the backcasting analysis for several data errors, the model continued to over-estimate actual 2010 energy net revenues by about $1.2 million or 45%. An error of this magnitude is too great, in our opinion, to inspire confidence in the ability of the model to reasonably predict future performance.

[17] A summary of the results of the backcasting analysis is presented in Table 2 of the report submitted by Jacobs Consultancy to Staff on July 25, 2011. The report is attached as Staff Exhibit-9.

**Q. DID LAI COMPLETELY REVISE THE APRIL 26, 2011 STUDY RESULTS TO DETERMINE THE EFFECTS OF HIGHER START-UP FUEL COSTS AND PLANT HEATING COSTS?**

A. No. LAI declined to revise the model a second time with higher start-up fuel costs arguing that the resulting change is unlikely to affect the overall conclusion that continued operation of the plant is economically sound. LAI did, however, file a second revision to Exhibit G.12 that quantifies the net economic impact of plant heating costs. LAI's argument notwithstanding, Staff requested that LAI re-run the model with certain specified input changes including those discussed above.

**Q. WHAT INPUT DATA CHANGES DID YOU INCLUDE IN THE REQUESTED MODEL RE-RUN?**

A. In addition to the use of higher start-up fuel costs and the inclusion of plant heating costs, Staff requested the following:

a. When calculating natural gas fuel expenses, add an 80 cents/MMBtu premium to the Dracut daily natural gas prices in the months January-February and an 84 cents/MMBtu premium in all other months.
b. Change the residual fuel oil to natural gas price ratio in 2011 to 4.0:1 narrowing on a linear basis to 3.5:1 in 2020. Also change the #2 fuel oil to natural gas price ratio in 2011 to 5.0:1 narrowing on a linear basis to 4.5:1 in 2020.

**Q. WHAT IS THE BACKGROUND TO THE CHANGE IN NATURAL GAS PRICES IN THE RE-RUN?**

A. In the model, the forecast of Newington's natural gas fuel expenses is based on a forecast of daily natural gas prices at Dracut plus a 75 cents/MMBtu premium in the months January-February and a 17.5 cents/MMBtu premium in all other months. The inclusion of these premiums in the model was based on instructions from PSNH to LAI. However, a review by Staff of actual 2010 invoices from Newington's natural gas supplier, Emera, revealed weighted average premiums of 80 cents/MMBtu for the months January-February and 84 cents/MMBtu for all other months.[18] For this reason, we believe the model understates Newington's actual natural gas costs and, in consequence, overstates actual energy net revenues. The pricing changes requested by Staff are designed to correct this error.

**Q. WHAT IS THE BACKGROUND TO THE CHANGES IN FUEL PRICE RATIOS?**

A. The fuel price forecasts included in the model are based on forward prices as of August 27, 2010. On that day, the residual fuel oil/natural gas price ratio started at 2.5:1 in 2011 and declined to 1.75 in 2020. Since that time the ratio has

[18] The premiums are based on the weighted average prices for natural gas delivered to Newington for days when Newington operated on natural gas.

grown considerably and now stands at about 4.4:1. The proposed price ratio trend reflects this recent growth plus the expectation that future changes in RFO and natural gas prices are unlikely to reduce the ratio significantly over the next ten years.

**Q. WHAT WERE THE RESULTS OF THE RE-RUN REQUESTED BY STAFF?**

A. As noted above, the revision filed by PSNH on April 26, 2011 reduced the expected NPV of energy net revenues from $120 million to $39 million and the overall NPV for the plant from $152 million to $72 million. The results of the re-run filed July 12, 2011 reduced the expected NPV of energy net revenue to less than $5 million and the NPV of the overall benefit to $37 million.[19] These changes are summarized in Table 1 below.

**Table 1**

**Comparsion of Modeling Results**
**(Present Value $,000)**

| | Original Filing | Revised Filing | Staff Re-Run |
|---|---|---|---|
| Energy Net Revenue | $120,172 | $39,339 | $4,654 |
| Capacity Revenue | $111,205 | $111,205 | $111,205 |
| Ancillary Service Revenue | $1,367 | $1,367 | $1,367 |
| Non-Fuel Related Incremental Costs | $80,443 | $80,443 | $80,443 |
| Net Benefit | $152,301 | $71,468 | $36,783 |

[19] PSNH response to Technical Session 2-7 attached as Staff Exhibit-10.

**Q. DO YOU HAVE OTHER CONCERNS WITH THE MODEL THAT COULD POTENTIALLY INVOLVE FURTHER REDUCTIONS TO THE EXPECTED FUTURE VALUE OF THE PLANT?**

A. Leaving aside our more general concern that the model does not reflect actual operations, we have two other specific concerns. The first relates to the proposed Northeast Utilities/NSTAR Northern Pass Transmission Project and its potential impact on Newington's profitability.[20] Our concern is that low-cost hydroelectric power delivered to the ISO-NE region via the transmission line would displace energy produced by inefficient, high cost generators like Newington. The net result would be a smaller NPV of energy net revenues and a corresponding reduction in the overall plant NPV.[21]

**Q. YOU SAID LAI DID NOT ANALYZE THIS ISSUE IN ITS STUDY. ARE YOU ABLE TO QUANTIFY THE ABOVE MENTIONED POTENTIAL IMPACT?**

A. Not at the moment. Charles River Associates (CRA) was hired by NU to analyze the impact of Northern Pass on the profitability of the region's generators. The workpapers attached to CRA's report apparently contain generation, cost, revenue and profit margin data for each regional power plant

[20] LAI did not take this issue into account in its study.
[21] While the delivery to the region of low cost firm energy would also be expected to put downward pressure on FCM prices, we do not address that issue in this testimony.

including Newington.[22] At the time of writing, however, Staff did not have access to this data and could not, therefore, estimate the magnitude of the potential change. If this data is made available to Staff, we intend to update our testimony to provide CRA's estimates of the potential change in annual energy net revenue for the plant.

**Q. WHAT IS YOUR SECOND CONCERN?**

A. PSNH contends that the plant is unlikely to undergo significant refurbishment, upgrade or replacement during the ten-year analysis period to maintain or improve plant performance, meet existing or new environmental regulations, or maintain plant availability.[23] [***BEGIN CONFIDENTIAL***] [redacted] [***END CONFIDENTIAL***] PSNH response to Staff 1-57, which is attached as Staff Exhibit-11 to this testimony, shows that actual annual capital expenditures for Newington have been as high as $6 million and as low as $110,000 over the last six years, averaging just over $2 million.[25]

[22] These workpapers are currently the subject of a motion to compel filed by TransCanada.
[23] PSNH response to Staff 1-42 attached as Staff Exhibit-11.
[redacted]
[25] PSNH response to Staff 1-57 attached as Staff Exhibit-13.

**Q. COULD THE LOWER COST ESTIMATE BE EXPLAINED BY A CHANGE IN HOW THE PLANT WILL BE OPERATED GOING FORWARD?**

**A.** Possibly, but the data do not support that conclusion. Exhibit G.3 to the original CUO study shows that between 2006 and 2010 the plant capacity factor never reached 10% and only exceeded 9% one time. Despite these relatively low levels of performance, the Company continued, with one exception, to issue five-year capital budgets for Newington that contained annual expenditure estimates averaging over $2 million per year. That one exception was 2010, the year the original CUO study was prepared. The original CUO study, however, did not project that the plant would operate less in the future than it did in recent years. On the contrary, LAI projected that the plant capacity factor would be significantly higher in the future, at between 15% and 19%, than it had been in recent years. In short, the much lower level of capital expenditures used by LAI in its model was not predicated on a reduction in plant output compared to the recent past. For these reasons, Staff believes PSNH's projection of capital expenditures over the analysis period is questionable, and perhaps should be higher.

**Q. WHY DO YOU THINK THE CAPITAL EXPENDITURES COULD, IN FACT, BE HIGHER THAN THE LEVEL INCLUDED IN THE LAI ANALYSIS?**

A. There are several reasons. First, I have already mentioned the difference in the projected level of capital expenditures versus the historical level and the annual amounts included in the Company's own forecasts. Second, there are potential compliance costs stemming from recent EPA actions which may add to the necessary capital projects at Newington.

**Q. DOES PSNH'S CAPITAL COST ESTIMATES TAKE INTO ACCOUNT THE POTENTIAL COST OF COMPLYING WITH THE EPA'S NEW RULE ON POWER PLANT EMISSIONS?**

A. No, PSNH states that without a final rule in hand, specific compliance costs cannot be determined.[26] Nevertheless, the EPA's proposed new rule on mercury, non-mercury metals, and acid gas emissions, which was mandated by the courts, could force PSNH to make additional expenditures on expensive control equipment-possibly a sorbent or activated carbon injection system -to reduce mercury emissions. If PSNH is required to install such a system at Newington, and the compliance date for the rule remains 2015, it is possible that additional expenditures could be required as early as 2013 or 2014 to cover the cost of the

[26] PSNH response to Staff 2-9 attached as Staff Exhibit-14.

equipment and its installation. Such expenditures could be followed by additional operating costs through the end of the analysis period.

Q. **IS THERE A SECOND RULE, THE THERMAL POWER PLANT COOLING WATER INTAKE STRUCTURES RULE, WHICH COULD REQUIRE ADDITIONAL CAPITAL EXPENDITURES?**

A. Yes, this rule may force PSNH to install expensive cooling towers at Newington to reduce the amount of cooling water drawn from the Piscataqua River. Although the cost of such an installation is not currently known, the net effect would be to further reduce (and possibly eliminate) the overall net benefit of continuing to operate the plant.

Q. **DO YOU HAVE OTHER COMMENTS ON PSNH'S TREATMENT OF CAPITAL EXPENDITURES?**

A. Yes. Because of the uncertainty associated with the level of going-forward capital expenditures, we believe LAI should have used a model similar to the one it used to forecast capacity revenues. Had LAI modeled capital expenditures this way, the plant's overall net benefit would likely have been smaller than estimated.

Q. **DO YOU HAVE ESTIMATES OF THE CAPITAL EXPENDUTURES REQUIRED TO COMPLY WITH THE EPA NEW RULES?**

A. No, we do not. Nevertheless, if we assume for illustrative purposes that PSNH is required to install an activated carbon injection system to meet the requirements of the EPA's new emissions rule and that the cost to acquire and install that system in 2014 is $20 million and $0.5 million annually thereafter to cover the operating costs of the injection system, the overall net benefit of continuing to operate the plant for another 10 years would fall from about $37 million to about $19 million.[27] Obviously, the reduction in net benefit would be considerably larger if PSNH was also required to install an expensive cooling tower at Newington.

Q. **HOW DOES A $19 MILLION TO $37 MILLION CUSTOMER NET BENEFIT FROM CONTINUED OPERATION COMPARE TO THE SAVING IN DEPRECIATION EXPENSE IF THE PLANT WAS RETIRED?**

A. As of year-end 2010, Newington had a total rate base of $72 million comprising $46 million of net plant and $25 million of fuel oil inventory. Assuming the net plant investment is fully depreciated over the 10 year analysis period and the fuel inventory is expensed in equal annual amounts, we estimate customers would pay

[27] See Staff Exhibit-15.

approximately $51 million in depreciation charges in NPV terms.[28] However, drawing down the fuel oil inventory and selling the product at market value would produce offsetting savings for customers, which we estimate could be worth around $17 million in NPV terms at current market prices. Thus, the net depreciation expense payment made to PSNH would be about $34 million assuming the plant continues to operate. If this payment is avoided by retiring the plant, customers could experience a net saving of between + $15 million and -$3 million.

Q. **PLEASE SUMMARIZE YOUR KEY CONCLUSIONS.**

A. Staff's conclusions are summarized as follows:

(1) The original CUO Study filed September 30, 2010 asserted that continued operation of Newington would provide an economic benefit to customers of $152.3 million over the 10-year analysis period. This study was later revised to correct multiple errors.

(2) The revised CUO Study filed April 26, 2011 asserted that continued operation would provide an economic benefit to customers of $71.5 million over the same period or less than half the original amount.

(3) A re-run of the April 26, 2011 study requested by Staff with alternative input assumptions reduced the expected economic benefit to $36.8 million. Unlike the original study's forecasted benefits, this benefit is mostly comprised of revenues from ISO-NE's Forward Capacity Market.

(4) The $36.8 million economic benefit resulting from the re-run of the model is not assured. The forecast of capital expenditures on which the result is based is questionable. An alternative forecast that reflects the level of expenditures in recent years would produce a lower benefit for customers. If additional capital expenditures are required to comply with new federal rules on emissions and cooling water, the benefit to customers would be lowered further and possibly eliminated.

[28] We estimate PSNH would also receive approximately $27 million in return on investment over that period.

(5) The methodology used to develop the forecast of market capacity prices that underlies the capacity component of the $36.8 million economic benefit takes no account of the impact the proposed Northern Pass Transmission Project may have on capacity prices.

(6) The methodology used to develop the forecast of market energy prices that underlies the energy component of the $36.8 million benefit takes no account of the impact the proposed Northern Pass Transmission Project may have on energy prices. Assuming the workpapers associated with CRA's study on Northern Pass are made available to Staff, we propose to update our testimony to include an estimate of the impact.

(7) Notwithstanding the changes in the model results summarized in conclusions (3) through (6) above, the fact that Jacobs was not given access to the model and some of the critical input data means that we cannot issue a definitive opinion on the reasonableness of the model design.

(8) An potential economic benefit to customers in the range $17 million to $37 million over ten years associated with continued operation of Newington compares with potential depreciation savings of about $34 million if the plant is retired.

Q. **WHAT DO YOU RECOMMEND?**

A. Given the uncertainty over the ratemaking treatment that the Commission will apply to past capital investments, the impact of the Northern Pass Transmission project on energy and capacity prices, and the level of capital expenditures needed to comply with the EPA's new rules on emissions and cooling water, Staff is unable to state definitively that customers would be better off if Newington continues to operate or is retired. For this reason, we make no recommendation.

Q. **DOES THAT CONCLUDE THE CUO PORTION OF YOUR TESTIMONY?**

A. Yes.

## III DEMAND-SIDE ASSESSMENT

Q. **PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S DEMAND-SIDE RESOURCE ASSESSMENT.**

A. In this section of the IRP, PSNH began by reviewing the demand-side programs currently offered through its CORE Programs and documented the energy savings achieved to date. This was followed by an assessment of the potential for demand-side resources in PSNH's service territory. Finally, based on the results of that assessment, PSNH discussed possible future offerings.

Q. **PLEASE ADDRESS THE COMPANY'S ASSESSMENT OF DEMAND-SIDE RESOURCE POTENTIAL.**

A. In Order No. 24,945, the Commission directed the Company to "base its assessment of demand-side resources on the results of the report on "*Additional Opportunities for Energy Efficiency in New Hampshire*" [prepared] by GDS Associates, the consultant hired by the Commission to investigate the potential for energy efficiency in New Hampshire" (GDS Study). GDS developed four different estimates of energy efficiency potential:

- Technical Potential
- Maximum Achievable Potential
- Maximum Achievable Cost Effective Potential
- Potentially Obtainable Scenario

As explained in both the GDS Study and the 2010 IRP, these estimates represent a hierarchy of defined potential starting at the broadest level of technical feasibility and then introducing progressively more restrictive criteria of achievability based on market turnover, cost-effectiveness, and market acceptance. The demand-side resource potential in PSNH's service territory, which is referred to in the 2010 IRP as the Market Potential Scenario, is based on the methodology that GDS used to develop the Potentially Obtainable Scenario. Specifically, PSNH's approach consisted of the following elements:

1. Review the Potentially Obtainable methodology and results;
2. Translate the Potentially Obtainable savings data from the 10-year state-wide estimates into annualized savings values specific to PSNH;
3. Identify the major measure/end use categories in which the estimated potential savings significantly exceed PSNH's program savings goals reported in the 2010 CORE New Hampshire Energy Programs;
4. Identify the priority measures within each major category that account for the majority of potential savings in that category;
5. Review and revise the technical/market assumptions employed in the development of the potential savings estimates for priority measures;
6. Select priority measures for inclusion in the Market Potential Scenario;
7. Determine the program design elements, customer incentive levels and other program costs required to achieve the estimated Market Potential;
8. Develop Market Potential Scenario annual program participation, cost and savings projections for the planning period 2011-2015;
9. Conduct TRC analysis of Market Potential Scenario.

Q. **THE ABOVE ELEMENTS INDICATE THAT THE MARKET POTENTIAL SCENARIO DIFFERS FROM THE POTENTIALLY OBTAINABLE SCENARIO IN PART BECAUSE PSNH PROVIDES SERVICE TO ONLY A PORTION OF THE STATE AND IN PART BECAUSE SOME OF THE TECHNICAL/MARKET ASSUMPTIONS**

**UNDERLYING THE GDS STUDY HAVE BEEN CHANGED. IS THIS A REASONABLE SUMMARY OF STAFF'S POSITION?**

A. Yes.

Q. **WHAT IS THE EXTENT OF THE DIFFERENCE BETWEEN THE TWO SCENARIOS?**

A. A comparison of the Market Potential and Potentially Obtainable scenarios is provided in Table 2 below. As is evident from the table, the difference between the two scenarios is relatively small for the C&I sector (+6%) and relatively large for the residential sector (-73%).

TABLE 2

Comparison of Potentially Obtainable and Market Potential
(Annualized MWH Savings)

| C&I Measure Category | C&I Potentially Obtainable | C&I Market Potential |
|---|---|---|
| New Construction | 2,866 | 5,834 |
| Existing lighting | 15,211 | 15,452 |
| Existing HVAC | 12,350 | 12,350 |
| Existing Other | 22,145 | 22,145 |
| Total C&I | 52,572 | 55,781 |

| Res. Measure Category | Res. Potentially Obtainable | Res. Market Potential |
|---|---|---|
| New Construction | 1,766 | 2,823 |
| Lighting | 27,447 | 2,421 |
| Refrigerator Removal | 5,280 | 1,954 |
| ES Appliances | 5,437 | 2,202 |
| HVAC | 2,537 | 1,141 |
| Domestic How water | 1,170 | 1,170 |
| Weatherization | 1,220 | 619 |
| Other | 5,404 | 1,223 |
| Total Residential | 50,261 | 13,553 |

**Q. ARE THE CHANGES TO THE ASSUMPTIONS THAT UNDERLIE THE GDS STUDY CONTRARY TO THE COMMISSION'S DIRECTIVE TO BASE THE DEMAND-SIDE RESOURCE POTENTIAL ON THE STUDY RESULTS?**

A. Yes, we believe so. The plain language of the Commission's directive appears to require the demand-side resource potential for PSNH to be estimated by scaling the GDS Study results to PSNH's service area. Changing the assumptions

certainly produces a different set of results and perhaps raises questions about the value of the GDS study.

Q. **DOES THE FOREGOING SUGGEST THAT THE MARKET POTENTIAL ESTIMATE SHOULD BE DISCARDED?**

A. Not necessarily. A major reason for the large difference between the Market Potential and Potentially Obtainable scenarios for the residential sector is the expected reduction in the savings from Compact Fluorescent Light (CFL) bulbs and fixtures due to the phase-in of the Energy Independence and Security Act of 2007 (EISA) lighting performance standards.[29] Because the GDS Study did not account for the impact of these standards, the lighting savings in that study are overstated.[30] The Market Potential scenario appropriately recognizes this omission and corrects for it.

Q. **ARE THERE OTHER REASONS FOR THE RESIDENTIAL SECTOR DIFFERENCE?**

A. Yes. Although CFLs are expected to be significantly more efficient than incandescent lamps that comply with the EISA standard, the Market Potential scenario does not reflect the savings associated with the displacement of these more efficient incandescent lamps by CFLs. If the Market Potential had reflected this savings opportunity, the difference between the two scenarios would not be as

[29] The EISA lighting performance standards require improvements in the efficiency of incandescent bulbs, the base technology from which current lighting savings are calculated.
[30] PSNH calculated that the EISA lighting standards will eliminate over 40 percent of the 2015 Obtainable Potential for the residential sector.

great. PSNH's reason for omitting this saving is that the incremental cost of the CFLs over the advanced incandescent products is not expected to be sufficient to warrant a rebate.[31] The implication is that eliminating the rebates would reduce the likelihood of achieving the energy savings.

Q. **DO YOU ACCEPT THIS JUSTIFICATION FOR DISREGARDING THE CFL-RELATED SAVINGS?**

A. No. Although PSNH acknowledges that spending program dollars on marketing is a more effective way of raising customer awareness of efficient lighting products than the payment of rebates, it contends that that it has no plans to replace the current rebate programs with marketing programs. Accordingly, we believe the Company has understated the savings potential for the residential sector.

Q. **WHAT EFFECT WOULD RETAINING THE REBATE PROGRAMS HAVE ON THE 2015 MARKET POTENTIAL?**

A. This information was not provided in the Company's filing.

Q. **ABOVE YOU NOTED THAT THE 2015 ANNUALIZED RESIDENTIAL SECTOR SAVINGS UNDER THE MARKET POTENTIAL SCENARIO IS 73% LESS THAN THE CORRESPONDING QUANTITY UNDER THE GDS STUDY. DOES THE COMPANY EXPECT THAT THIS SMALLER**

[31] In such cases, PSNH believes that efforts to raise customer awareness of efficient products would be a more effective use of program funds than the payment of rebates to defray a small cost difference.

**POTENTIAL WILL LIMIT ITS ABILITY TO EXPAND ITS RESIDENTIAL PROGRAMS?**

A. Yes. Exhibit IV-8 in the LCIRP shows that the 2015 residential savings potential under the market potential scenario is 11% less than the savings PSNH expects to achieve from its approved 2010 residential programs. Again, this decline is attributable to the phasing out of the CFL measures in the Energy Star Lighting program.

Q. **DOES THE COMPANY PROJECT A CORRESPONDING REDUCTION IN THE COST TO ACHIEVE THE LOWER LEVEL OF SAVINGS POTENTIAL?**

A. No. The expected annual cost to achieve the 2015 residential savings potential is shown in Exhibit IV-8 as $18 million, almost three times the residential budget for 2010. The reasonableness of this cost increase can best be determined by separating the Company's largest program in terms of energy savings, the Energy Star Lighting program, from all others. Over the five-year period 2010-2015, PSNH calculates that annual savings potential for its non-Energy Star Lighting programs could increase 3.25 times while the annual cost to achieve those savings could increases only 2.94 times. These data suggest that the increase in annual cost for the non-Energy Star Lighting programs is justified based on growth in annual savings.

The annual savings potential for the Energy Star Lighting program, however, is expected to fall to only 20% of its 2010 level by 2015 while the annual cost of

that program is expected increase 30% over the same period. These data raise questions about PSNH's cost and/or savings estimates for the Energy Star Lighting program.

Q. **DOES THE COMPANY ADDRESS IN ITS FILING WHY THE COST TO ACHIEVE A DECLINING SAVINGS POTENTIAL RISES SIGNIFICANTLY?**

A. No, it does not. Although we understand the answer has to do with: (i) the increasing cost of programs as the number of participants rises; and (ii) the expansion of fuel-blind programs,[32] we think it is important that the Company close this gap in its filing.

Q. **WHAT CONCLUSIONS DID THE COMPANY DRAW FROM THE RESULTS OF ITS ECONOMIC ANALYSIS OF THE MARKET POTENTIAL SCENARIO?**

A. PSNH stated that the economic analysis supports the following primary conclusions:

1. The potential exists to significantly expand the scale of Energy Efficiency programs to achieve proportionately higher energy savings and associated economic benefits for PSNH customers.
2. The opportunities to increase expenditures and savings lie principally in the commercial and industrial sectors, mainly due to the offsetting effect of phasing out CFL measures.

[32] Staff understands that while the costs of fuel-blind programs are included in the Company's cost estimates, the non-electric energy savings associated with those programs are excluded from the energy savings estimates.

Q. **DOES STAFF AGREE WITH THESE CONCLUSIONS?**

A. Although we do not dispute the accuracy of the two conclusions, we believe they present a rosier picture of the future for energy efficiency in New Hampshire than is warranted. Specifically, PSNH fails to emphasize the prospect, clearly evident in its filing, that residential program savings are likely to contract in the future while the cost to achieve those savings grows considerably larger.

Q. **DOES THAT CONCLUDE THE DEMAND-SIDE ASSESSMENT PORTION OF YOUR TESTIMONY?**

A. Yes.

Q. **DO YOU HAVE ANYTHING FURTHER TO ADD?**

A. No.