STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire) Petition for Approval of Integrated Least) Cost Resource Plan)	Docket No. DE07-108

REDACTED

DIRECT TESTIMONY
OF
GEORGE R. McCLUSKEY

June 6, 2008

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 Electric Division.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I am a utility ratemaking specialist with over 20 years experience in utility economics. I rejoined the Commission in March 2005 after working as a consultant for La Capra Associates for five years. Before joining La Capra, I directed the Commission's electric utility restructuring division and before that 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 presented or filed testimony before state regulatory authorities in New Hampshire, Maine, Ohio and Arkansas and before the Federal Energy Regulatory Commission. A copy of my resume is included as Exhibit GRM-1.

Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to present Staff's comments on Public Service Company of New Hampshire's ("PSNH" or "Company") resource planning as described in its September 30, 2007 Least Cost Integrated Resource Plan ("LCIRP") and the supplements filed March 28, 2008.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I begin in Section II by reviewing the standards for Commission review and approval of electric utility LCIRP filings. In Section III, I comment on the Company's demand-side assessment and in particular the proposal to fill a portion of the projected resource balance with an expansion of the Core Energy Efficiency programs. This is followed in Section IV with my comments on the package of supply-side resources that the Company believes would best meet customer demands over the planning horizon if it had the legal authority to acquire such resources. I also address in Section IV whether a continued unit operation study of Merrimack Station should be conducted before a final commitment to the installation of costly scrubber technology is made.

Q. BEFORE YOU BEGIN YOUR DISCUSSION OF THE STANDARD FOR REVIEW OF LEAST COST INTEGRATED RESOURCE PLANS, PLEASE SUMMARIZE STAFF'S CONCLUSIONS.

A. Staff's conclusions are summarized as follows:

(1) PSNH did not perform an assessment of the potential for demand-side resources in its service territory. Nonetheless, information on the technical and economic potential of demand-side resources for New Hampshire should become available later this year when the consultant hired in response to the Commission's energy efficiency RFP submits its report.

(2) PSNH's conclusion that an ISO-NE administered demand response program should not be implemented at this time is not supported by the Company's own analysis, which understates the customer benefits.

(3) The benefits adder for environmental externalities included in the cost effectiveness test for demand-side resources should be removed.

(4) The generic cost information provided by PSNH relating to the construction or acquisition of new generation options is deficient in several important respects. First, the revenue requirements estimates for the wind and biomass options leave out the cost of transmission. Second, the revenue requirements estimates for the biomass and peaking plants do not include the cost of land or reflect the need for capital additions. Third, the cost of fuel for the biomass and peaking plants is assumed unrealistically to decline in real terms over the plant lives. Fourth, even though the federal Business Energy Tax Credit is due to expire at the end of 2008, and is not currently available to public utilities, the tax credit was included in the revenue requirements for solar PV. Fifth, the method used to rank the new generation options is flawed. Based on these conclusions, Staff argues that the generic cost information does not support giving PSNH the authority to construct or acquire new generation capacity.

(5) PSNH should conduct an analysis to determine whether continued operation of the Merrimack Station is economic relative to market purchases when the costs of installing and operating the scrubber are taken into account.

(6) PSNH should conduct an analysis to determine whether continued operation of the Newington Station is economic relative to market purchases based on fuel costs that are reflective of current forward prices.

II. STATUTORY REQUIREMENTS

Q. WHAT STANDARDS HAVE YOU APPLIED IN ASSESSING WHETHER THE COMPANY'S LCIRP IS ADEQUATE?

A. The starting point for any discussion of the adequacy of an electric utility's LCIRP must be RSA 378:38, New Hampshire's least cost energy planning statute. This statute specifies that each LCIRP must include at a minimum the following reports:

1. A forecast of future electrical demand for the utility's service area;
2. An assessment of the demand-side energy management programs, including conservation, efficiency improvement, and load management programs;
3. An assessment of supply-side options;
4. An assessment of transmission requirements;
5. Provision of diversity of supply sources;
6. Integration of demand-side and supply-side options;
7. An assessment of plan integration and impact on state compliance with the Clean Air Act Amendments of 1990;
8. An assessment of plan integration and impact on state compliance with the National Energy Policy Act of 1992[1];

[1] I would assume that this report would relate to the recent amendments to the 1992 Act.

9. An assessment of the plan's long- and short-term environmental, economic and energy price and supply impact on the state.

Q. HAS THE COMMISSION PROVIDED ANY GUIDANCE ON THE CONTENT OF THE ABOVE REPORTS?

A Yes it has. Most recently in Order No. 24,695 the Commission approved a partial settlement agreement in Docket DE 04-072, PSNH 2004 LCIRP, which resolved some of the filing requirement issues that had arisen during the course of the proceeding. In addition, the Commission resolved several issues where the parties failed to reach agreement. Since all of these issues have implications for the current proceeding, I present brief summaries of each starting with those on which agreement was reached:

(1) The planning period for PSNH's 2007 LCIRP will be as long as the single longest lead time for generation resource options, but in no event shorter than five years;
(2) The report on load forecasts for delivery and energy services will address the specific issues identified in the order;
(3) Energy and capacity resource balances will be identified;
(4) Reasonably available supply-side resource options to meet the projected resource balance will be identified and an assessment of base-load, intermediate and peaking needs provided;
(5) A long-term wholesale price forecast will be provided;
(6) The coal procurement strategy will be described including efforts to reduce coal transportation costs;
(7) The impact of anticipated changes in fuel procurement regulations will be discussed along with the impact those changes are likely to have on the cost of fossil-fired generation;
(8) A description of the hedging strategy will be provided;
(9) Reasonably available alternatives to the existing strategy for meeting SO2 regulations will be described and evaluated. In addition, the SO2 compliance plan will be described and its impact on retail rates quantified;
(10)Reasonably achievable production adaptations, market-based mechanisms or other alternatives that could be used to comply with Phases I and II of New Hampshire's Clean Power Act or proposed regional or federal programs to decrease power sector C02 emissions

will be described. In addition, the potential rate impact of any compliance plan will be quantified;

(11) Alternatives for complying with potential state and federal mercury emissions regulations will be described. In addition, the mercury emissions compliance plan will be discussed and its potential rate impacts quantified;

(12) The process for integrating demand-side and supply-side resources at the lowest reasonable cost will be described.

The disputed issues were decided as follows:

(1) The Company's request for a waiver of the requirement in RSA 378:38 that electric utilities address generation in their LCIRPs is denied;

(2) Generic cost information on the construction or acquisition of reasonably available new generation options will be provided;

(3) Supply-side resource options will be evaluated based on net present value of revenue requirements. The options will be ranked from lowest net present value relative to the cost of market purchases to the highest;

(4) In evaluating supply-side options, the following criteria will also be taken into account: (i) environmental compliance costs; (ii) fuel diversity; (iii) availability at the time of system peak; and (iv) the ability to promote price stability;

(5) The Company is not required to evaluate the costs and benefits of divestiture in the context of an LCIRP;

(6) The Company is directed to include in its next LCIRP: (i) a systematic evaluation of reasonably available DSM programs; (ii) a description of the avoided cost methodology that forms the basis of that evaluation; and (iii) the resulting avoided cost forecast.

(7) The Company will undertake a study to determine the effects of using the Rate Impact Method test on demand side management resource availability.

Q. DOES THE LCIRP COMPLY WITH THE REQUIREMENTS OF ORDER NO. 24,695?

A. Not completely.

III. ASSESSMENT OF DEMAND-SIDE PROGRAMS

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

A. In order to determine whether a portion of the projected capacity and energy shortfall could be met at least cost with an expanded program of demand-side resources, the Company claims that it examined whether sufficient cost-effective demand-side resources are available to support such an expanded program.[2] The Company then analyzed how much of this potential could be realized by increasing the size of the Core Energy Efficiency programs. Three funding levels were considered:

- 25% increase in the EE portion of the SBC to 2.25 mills per kWh
- 50% increase in the EE portion of the SBC to 2.7 mills per kWh
- 67% increase in the EE portion of the SBC to 3 mills per kWh

The Company calculated, for example, that a 50% increase in funding would reduce peak demand by 26 MW by 2012 and save 97,000 MWH.

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

A. In Order No. 24,695, the Commission directed the Company to conduct a systematic evaluation of reasonably available demand-side resources. In response to that directive, the Company began its demand-side assessment with what it termed as "an assessment of the available demand side potential." A careful review of the filing reveals, however, that the Company did not in fact assess the potential for demand-side resources in its service territory. To conduct such an

[2] PSNH used the Total Resource Cost test to determine cost-effectiveness.

assessment would require an end-use breakdown of electric consumption, data on the penetration and saturation of energy efficiency equipment in each end-use sector, and knowledge of the currently available and soon to be commercially available technologies which could play a part in future energy efficiency programs including estimates of usage per customer and savings. None of these issues is addressed in the LCIRP. Instead, the Company developed several so-called benchmarks that it claims "can be employed to assess the resource potential of DSM activities" such as the energy and peak demand savings that would result under: (i) a no load growth strategy; (ii) the assumption that DSM funding would continue at its current level through the end of the planning period; or (iii) the assumption that DSM funding would be expanded to say 3 mills/kWh. The results of these estimates, which are summarized at Exhibits IV-3 & 5 of the LCIRP, would better be described as DSM goals/targets rather than DSM potential. Accordingly, Staff believes that the Company's estimates on the potential for demand-side resources should be disregarded. For its next LCIRP, Staff recommends that the Company use information from the report to be filed by the consultants hired in response to the Commission's RFP - Evaluating Additional Opportunities for Energy Efficiency in New Hampshire.

Demand Response Programs

Q. THE COMPANY EXAMINED A NUMBER OF PROGRAM OPTIONS FOR POSSIBLE INCLUSION IN AN EXPANDED SET OF PROGRAM OFFERINGS THAT WOULD FILL SOME OF THE RESOURCE BALANCE INCLUDING COOL STORAGE AND DEMAND RESPONSE. WHAT CONCLUSIONS DID THE COMPANY REACH REGARDING THESE OPTIONS?

A. PSNH concluded that cool storage technology is not cost effective in New Hampshire in part due to the cool climate and in part due to the lack of price differentiation in retail rate structures.

As for demand response, PSNH analyzed two incentive scenarios: (i) a $80/kW-yr customer incentive; and (ii) a $40/kW-yr customer incentive payment that approximately corresponds to the current ISO-NE capacity transition payment.[3] Under the $80/kW-yr customer incentive, PSNH concluded that demand response would not be cost-effective until 2011, when the full value of new capacity is projected to be reflected in the Forward Capacity Market. Even then, the Company found that the option is just barely cost-effective. Under the $40/kw-yr customer incentive, demand response was estimated to be marginally cost-effective in 2009 and strongly cost-effective in 2011. For these reasons, PSNH recommended that demand response not be implemented at this time and instead the economics of this option be reviewed again in the next LCIRP.

[3] Other program costs include metering and communications infrastructure costs, Internet Based Communications System contractor fees, and administrative costs.

Q. IS STAFF SURPRISED BY THIS RECOMMENDATION?

A. Yes, the recommendation appears to conflict with the results of the Company's economic analysis of peaking units which is included in its supply-side assessment. In that analysis, the Company concluded that installation of a peaking unit would produce significant cost savings for customers (primarily in the form of avoided Forward Capacity Market payments) over the life of the unit. Although the analysis indicates costs exceed benefits in the early years, the Company appears to believe that installing the unit in 2010 would be in the public interest. In contrast, the Company believes that paying participating customers to reduce peak period demands in 2010 (so that all customers can benefit from essentially the same ISO-NE savings generated by the peaking unit) is not in the public interest even though the program was determined to be cost effective in that year (if only marginally) and cost effectiveness was projected to improve significantly over time.

Q. DOES STAFF ACCEPT THAT DEMAND RESPONSE IS ONLY MARGINALLY COST EFFECTIVE IN 2010?

A. No, for several reasons. First, PSNH assumed that program participation requires each customer to incur an incremental metering cost. However, the customers most likely to benefit from this program are large C&I customers who already have real-time meters installed. Consequently, the incremental metering cost under thc program should be zero.

Second, PSNH assumed that transmission costs would not be avoided. Although the primary benefit of demand reductions under an ISO-NE sponsored demand response programs is the avoidance of Forward Capacity Market payments, such demand reductions are also likely to lower PSNH's transmission expense under its service agreements with ISO-NE and NU. These costs savings should have been incorporated into the analysis.

Third, demand reductions under the program are also likely to produce savings in distribution system reinforcement costs even though distribution system peak demands are not fully coincident with generation/transmission system peak demands. These investment cost savings should have been estimated and included in the analysis.

Fourth, PSNH provided no support for its assumption that an administrative cost of $5,000 per participant would be incurred. Even if such costs are incurred, PSNH has not shown that they would be incremental and therefore includable in the analysis.

Q. WHAT DOES STAFF RECOMMEND?

A. Staff recommends that the Company undertake a more detailed assessment of demand response programs taking into account the above comments. Based on the results of that assessment, the Company should recommend to the Commission whether the public interest would be served by offering such a program to large customers immediately.

Energy Efficiency Programs

Q. PSNH CLAIMS THAT IT USED THE TOTAL RESOURCE COST (TRC) TEST TO DETERMINE THE COST EFFECTIVENESS OF ENERGY EFFICIENCY PROGRAMS. IS THE EXECUTION OF THIS TEST CONSISTENT WITH COMMISSION POLICY?

A. No, the Company included a 15% benefits adder in the TRC Test to reflect "non-quantified benefits," which it describes as the "environmental and other benefits" associated with reduced energy usage.[4] This practice is contrary to the Commission's policy of not incorporating monetized environmental externality values in avoided cost analyses, which was recently re-affirmed in Order No. 24,695 in the section addressing PSNH's demand-side resource assessment.

Q. DID THE COMPANY INCLUDE THE 15% ADDER TO CAPTURE SOON-TO-BE INTERNALIZED ENVIRONMENTAL BENEFITS SUCH AS REDUCED CO2 EMISSIONS?

A. While that may have been the Company's intent, Staff is not certain because the term "environmental and other benefits" is not defined in the LCIRP. Staff does not believe, however, that the adder is intended to reflect the benefits of reduced CO2 emissions since those benefits are captured in the Company's avoided energy cost estimates.

[4] The Societal test is the name given to the TRC test with environmental externalities included.

Q. DOES STAFF HAVE OTHER CONCERNS WITH THE COMPANY'S EXECUTION OF THE TEST?

A. Yes. Although the test appropriately measures the costs and benefits of programs from the standpoint of both utility and participating customer, the Company has included participant benefits not typically included. These benefits are labeled "quantifiable resource savings" and relate apparently to non-electric bill savings, such as reduced water and gas (natural gas or propane) usage, associated with reductions in energy usage. While Staff is not familiar with energy efficiency programs that produce such secondary bill savings, it nevertheless believes that treating those savings as benefits in the TRC test is unreasonable. This is because the inclusion in the test of non-electric bill savings of participant customers has the effect of lowering the cost effectiveness bar but provides no offsetting benefits to non-participants. In other words, it turns programs that were previously marginally uneconomic into economic programs without any increase in benefits for those customers that pay the program costs.

Cost Effectiveness Tests

Q. THE COMMISSION IN ORDER NO. 24,695 DIRECTED PSNH TO UNDERTAKE A STUDY TO DETERMINE THE EFFECTS OF USING THE RATE IMPACT TEST (RIM) ON DSM RESOURCE AVAILABILITY. WHAT WAS THE STUDY'S CONCLUSION?

A. In order to determine the impact of not adopting the RIM test on the availability of demand side resources, PSNH applied the RIM test to the three most cost-effective DSM programs as determined by the TRC test. None of these programs passed the test, according to PSNH. Based on this result, the Company concluded that using the RIM test would disqualify many of the programs that have been determined to be cost effective under the TRC test and, therefore, lower the availability of demand-side resources. On the other hand, using the RIM test would ensure that no non-participating customer would be called on to subsidize the benefits participants derive from utility delivered programs.

Q. WHAT DO YOU RECOMMEND?

A. Staff recommends that the Company revise its TRC test to exclude both the 15% adder for non-quantified benefits and the component labeled "quantifiable resource savings." These changes will reduce the rate impact of energy efficiency programs experienced by non-participating customers.

IV. ASSESSMENT OF SUPPLY-SIDE OPTIONS

Q. DO YOU HAVE CONCERNS REGARDING THE COMPANY'S SUPPLY-SIDE ASSESSMENT?

A. Yes, Staff believes that the assessment is deficient in two important respects. The first relates to the generic cost information included in the LCIRP regarding the construction or acquisition of new generation options. The second relates to the omission of any discussion of whether continued operation of PSNH's existing generating stations, particularly Merrimack, is in the public interest.

Generic Cost Information

Q. WHAT IS THE BACKGROUND TO THE FIRST ISSUE?

A. Even though legislative approval would be required before PSNH could build or buy new generation, the Commission in Order No. 24,695 directed that generic cost information relating to new generation options be included in the Company's next integrated resource plan "so that an informed decision could be made by the Commission or the Legislature regarding whether the public interest would be served by authorizing PSNH to acquire new generation." The cost information included in the LCIRP relates to a 50 MW wood-fired power plant, 20-25 MW peaking units, and small scale renewable (solar and wind) generators. Other generation options such as new nuclear or new coal-fired capacity were rejected by PSNH for several reasons including perceived permitting difficulties and financial risks. A combined cycle natural gas-fired power plant was also rejected because PSNH believed such generation is unlikely to produce significant cost savings relative the market purchases.

Q. DOES STAFF AGREE THAT IT WOULD BE FUTILE TO INVESTIGATE THE NUCLEAR AND COAL-FIRED PLANT OPTIONS?

A. Staff believes that the Legislature is unlikely to be persuaded to consider siting a new nuclear facility in the state, despite the favorable economics of nuclear technology. Thus, Staff supports the Company's decision to remove that option from consideration. Staff, however, is less certain about the decision not to investigate the economics of coal-fired generation. This option was rejected on the ground that the minimum size for this type of plant is 600 MW, which would exceed PSNH's off-peak load requirement. However, the Company failed to consider the possibility of joint ownership with other generators or the sale of surplus output into the wholesale market. That said, Staff acknowledges that the cost of compliance with stringent emissions regulations (mercury and CO2) is likely to make this option far less cost effective in the future than today.

Q. WHAT CONCLUSIONS DID THE COMPANY DRAW FROM THE GENERIC COST INFORMATION?

A. As required by the Commission in Order No. 24,695, the Company calculated and presented the revenue requirements for each generation option, net of offsetting revenues, and compared the resulting present value to the present value of equivalent market purchases. Based on these analyses, the Company concluded that new biomass, peaking and wind power generation facilities would be cost effective relative to market purchases. Solar photovoltaic ("PV") generation was also determined to be cost effective provided federal legislation was passed that continued the Business Energy Tax Credit ("BETC") past 2008 and extended it to electric utility companies for solar PV installations. Absent such legislation, the Company concluded that solar PV is unlikely to be cost effective even with renewable energy credits (RECs) that are assumed to increase in value over the 20 year life of the installation.

Despite these conclusions, PSNH's best estimate of the capacity that could reasonably be added to its system within the five year planning horizon is 142 MW, comprising one 50 MW biomass plant facility, three 20 MW peaking units, 5 MW of solar PV installations, and 27 MW of wind generation.[5] This would still leave an on-peak capacity deficiency of over 700 MW to be met with market purchases.

[5] The estimate assumes that legislation would be passed that authorized the construction or acquisition of new generation capacity. Note that the solar PV and wind power capacities have been de-rated.

Q. DID THE COMPANY ALSO RANK THE GENERATION OPTIONS AS REQUIRED BY ORDER NO. 24,695?

A. Yes, the options were ranked but not based on the method specified in the Commission's order. The Company used a weighted system that included the following criteria:

1. Net revenue requirements;
2. Environmental compliance costs;
3. Fuel diversity;
4. Availability at time of system peak; and
5. Promotion of price stability.

Each criterion was assigned a weight based on PSNH's subjective determination of its value to customers. Net revenue requirements was assigned a weight of 0.3, environmental compliance costs 0.2, fuel diversity 0.15, availability at time of system peak 0.15, and promotion of price stability 0.2.

Q. WHAT WAS THE RESULT OF THE COMPANY'S RANKING ANALYSIS?

A. The Company ranked wind and solar PV panels (with BETC) first, biomass second, peaking units third, and solar photovoltaic panels (without BETC) fourth.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE COMPANY WAS WRONG TO INCLUDE THE ABOVE MENTIONED CRITERIA IN ITS RANKING SYSTEM WHEN ORDER NO. 24,695 STATES THAT THOSE CRITERIA SHOULD BE TAKEN INTO ACCOUNT WHEN EVALUATING SUPPLY-SIDE OPTIONS?

A. The Commission's order at page 25 is clear that the options should be ranked based on their net revenue requirements relative to the cost of market purchases. Staff believes that the Commission intended the other criteria be taken into account only when two or more options had the same or similar relative net revenue requirements.

Q. DOES STAFF HAVE CONCERNS WITH THE RANKING ANALYSIS OR THE REVENUE REQUIREMENTS ANALYSES THAT UNDERLIE THAT ANALYSIS?

A. Staff has concerns with both.

Q LEAVING ASIDE THE SUBJECTIVE NATURE OF THE COMPANY'S RANKING ANALYSIS, PLEASE OUTLINE SOME OF STAFF'S CONCERNS.

A. As noted above, the net revenue requirements criterion received the highest weighting at 30% followed by environmental compliance costs and price stability at 20%. The value to customers, however, of low environmental emissions is already reflected in the net revenue requirements estimates for the biomass, solar PV and wind generation options through the inclusion of REC revenues in the calculation.[6] Thus, inclusion of an environmental compliance cost criterion in the ranking analysis would amount to double counting of this attribute. In fact, it could be argued that it would amount to triple counting for solar PV since the revenue requirements for that technology include the BETC, whose purpose is to promote the use of technologies that do less harm to the environment.

The same argument would apply to the availability at system peak criterion because generation options that have high availability at system peak receive higher forward capacity market payments than options with low availability at system peak. Since these higher payments result in lower net revenue requirements, it would be double counting to include this attribute in the ranking analysis.

Q. IS THERE A MORE BASIC CONCERN WITH THE RANKING ANALYSIS?

A. Yes. The Company is attempting to rank generation projects that have totally different roles in PSNH's generation system. The biomass plant, for example, operates in the base load mode with an annual capacity factor of 90%. The peaking units, in contrast, have annual capacity factors of 1.5% and operate (as the name suggests) as peak shaving plants. Thus, the fuel-related revenue requirements for these dissimilar plant types will be different simply because they play different roles within PSNH's generation system. In addition, the biomass plant has a capacity of 50 MW whereas each peaking unit is only 21 MW, a fact that is guaranteed to produce different non-fuel related revenue requirements.

[6] While REC revenues may not reflect the true value customers place on low emissions, there can be little doubt that their inclusion makes renewable technologies more cost effective.

The point is that unadjusted net revenue requirements cannot logically be the basis on which projects that serve different purposes or differ in size are selected. While the latter problem can be resolved by calculating per unit revenue requirements, the problem of choosing between base load and peak shaving projects requires a different solution. Specifically, the Company should have calculated for each project the ratio of net revenue requirements to market purchases, with both quantities expressed in net present value terms. All projects with ratios less than one would be deemed economic relative to market purchases. Those with lower ratios would be viewed as having greater value to customers per dollar of expenditure than those with higher ratios.

Q. WHAT ARE STAFF'S SPECIFIC CONCERNS WITH THE REVENUE REQUIREMENTS ANALYSES?

A. Staff's first concern relates to the absence of transmission costs in the revenue requirements estimates for wind and biomass power plants despite the fact that such generators are likely to be located in the northern part of the state (where the wind blows strongly and wood fuel is plentiful) in an area where the existing transmission infrastructure needs to be upgraded or replaced before significant amounts of new generation can be connected to the system. The cost to upgrade the northern New Hampshire transmission system to accommodate additional generation has been estimated at \$210 million or between \$525/kW and \$700/kW. At the top end of this cost range, a 50 MW biomass plant could be responsible for an additional \$35 million and potentially much more depending on the methodology used to allocate transmission costs and the plant's position in the queue. Clearly, this is not an insignificant omission when compared to the $[redacted] million estimated capital cost of the plant.

Q. WOULD STAFF'S CONCERN ABOUT THE HIGH COST OF TRANSMISSION UPGRADES BE ADDRESSED BY USING THE PROCEEDS FROM THE SALE OF RENEWABLE ENERGY CREDITS TO FINANCE THAT EXPANSION?

A. No, the issue is not how to finance the expansion but rather whether the expansion is cost effective. If revenues from the sale of RECs are used to pay for the expansion, they will not be available to offset the otherwise uneconomic cost of wind and/or biomass generation.

Q. PLEASE DISCUSS STAFF'S OTHER CONCERNS.

A. Staff has several additional concerns. For example, the revenue requirements for the new biomass plant do not include the cost of land or reflect the need for capital additions to maintain efficient and reliable operations.[7] In addition, while the Company appropriately adjusted the capital cost of the plant estimated by R.W. Beck to recover costs not included in that estimate, the adjustment was made without the aid of a detailed cost analysis. Further, the Company assumed that the cost of biomass fuel would remain at $30/ton, the fuel price at the time of

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[7] The capital cost estimate for the biomass plant is based on work done by R.W. Beck under contract to PSNH. Beck's estimate, however, does not include taxes, licensing fees, and owners costs (such as land, management and administration costs, PSNH's contingency, AFUDC, legal fees, development costs, financing costs, and interconnection costs).

the filing. Stated differently, the cost of biomass fuel is expected to decline in real terms over the life of the plant; an assumption that was made without the aid of studies of the future supply and demand for biomass fuel in New Hampshire or the effect higher transportation costs may have on the delivered price of fuel.

Thus, the omission of transmission costs, land costs and capital additions, plus the questionable assumption that the cost of fuel will decline in real terms over the long term, results in revenue requirements estimates that Staff believes are unreasonably low and make the biomass option appear more cost effective than it really is.

Q. DO THE REVENUE REQUIREMENTS ESTIMATES FOR THE BIOMASS PLANT INCLUDE ENVIRONMENTAL COMPLIANCE COSTS?

A. Even though R.W. Beck determined that the [redacted] it appears that the capital and operating costs associated with such equipment are not included in the revenue requirements.[8] Staff notes, however, that biomass plants are considered carbon neutral and therefore are not subject to the requirements of CO2 emissions regulations. Accordingly, the revenue requirements estimates should exclude the CO2 compliance costs, which is the case with the Company's estimates.

[8] See Exhibit GRM 2 - PSNH Response to Staff 1-34.

Q. DOES STAFF HAVE ANY CONCERNS ABOUT THE REVENUE REQUIREMENTS ESTIMATES FOR THE PEAKING UNITS?

A. Yes. As with the price of biomass fuel, PSNH has assumed that the price of jet fuel for a peaking unit will remain constant throughout the life of the unit. Given the recent upward pressure on the price of oil, this assumption seems particularly unrealistic and at odds with the assumption that market energy prices will increase at the rate of inflation through 2040.

In addition, the Company assumed that annual fuel costs of $415,000 would be fully offset by energy market revenues from the sale of the output. However, under the scenario in which the output from the peaking unit is replaced with market purchases, the Company estimated that energy market costs would be approximately half the fuel costs. This suggests that the fuel-related component of the peaking unit revenue requirements is understated.

As regards non-fuel revenue requirements, Staff notes that the Company excluded the cost of land and the need for capital additions to maintain efficient and reliable operations.

Q. DOES STAFF ALSO HAVE CONCERNS ABOUT THE REVENUE REQUIREMENTS ESTIMATES FOR SOLAR PV PROJECTS?

A. Yes, Staff questions the optimism expressed in the LCIRP regarding solar PV panels. For example, even though the BETC is due to expire at the end of 2008, and is not currently available to utility companies, PSNH elected to include this tax credit in one scenario thus making utility ownership appear more cost effective than it really is.

Q. IS IT POSSIBLE THAT THE BETC WILL CONTINUE BEYOND 2008 AND BE EXPANDED TO COVER UTILITY COMPANIES?

A. While it is possible, it is important to note that a proposal before the United States House to achieve those ends was stripped from a larger bill and therefore did not move forward.[9] For this reason, Staff believes the Company was not justified in including this assumption in its analysis.

Q. DID THE COMPANY TAKE INTO ACCOUNT O&M EXPENSES IN ITS ECONOMIC ANALYSIS OF SOLAR PV?

A. No, O&M expenses were excluded from the revenue requirements calculations.

Q. DOES THE COMPANY'S OPTIMISM ABOUT SOLAR PV CONTRAST WITH THE VIEWS OF RENEWABALE ENERGY EXPERTS?

A. Yes. A recent study[10] conducted by Severin Borenstein, a professor at Berkeley's Haas School of Business and Director of the University of California Energy Institute, concluded that the costs of solar PV in the United States "far outweigh the benefits." Under the most extreme assumptions (such as a 5% annual increase in electricity costs and a 1% interest rate on money borrowed), Borenstein found that "the cost of solar PV is about 80% greater than the value of the electricity it

[9] See Exhibit GRM-3 - PSNH Response to Staff 1-44.
[10] The Market Value and Cost of Solar Photovoltaic Electricity Production,

will produce." Under more likely assumptions about electricity costs and interest rates, Borenstein found that "the cost of a solar PV installation today is three to four times greater than the benefits of the electricity it will produce." The gap is so large that including current plausible estimates of the value of reducing greenhouse gases does not make the current solar PV technology a worthwhile investment, Borenstein said.

Q. DOES BORENSTEIN'S STUDY TAKE INTO ACCOUNT FEDERAL TAX CREDITS AND STATE REBATES AND SUBSIDIES?

A. No, the Borenstein study analyzed the social value of solar PV rather than the private value. Thus, to the extent that a utility owner of solar PV facilities qualifies for a federal or state subsidy, the value of ownership would be greater than that calculated by Borenstein.

Q. DID PSNH CALCULATE THE PRIVATE VALUE OF OWNING SOLAR PV FACILITIES?

A. Yes, it concluded that even if solar PV is eligible for RECs that increase in value over the life of the installation it would still not be grid competitive if the BETC is not continued beyond 2008 and not extended to public utilities. Given that neither of these legislative results appears imminent, it is difficult to understand why PSNH would want to promote interest in solar technologies at this time.

Wholesale Price Forecast

Q. FOR EACH GENERATION OPTION, PSNH DETERMINED COST EFFECTIVENESS BY COMPARING THE ESTIMATED REVENUE REQUIREMENTS WITH THE COST OF WHOLESALE ENERGY AND CAPACITY PURCHASES OVER THE OPTION'S LIFE. DOES STAFF HAVE ANY CONCERNS WITH THE QUALITY OF THE ENERGY AND CAPACITY COST PROJECTIONS?

A. Staff has several concerns with the methodology used to develop the long-term forecast of market energy prices. PSNH's reference or base forecast is based on a combination of forward natural gas prices provided by a broker and natural gas prices estimated by the firm EVA using fundamentals analysis. Both sets of prices cover the period 2008 through 2012 and the forward prices are for delivery to Transcontinental Gas Pipeline Company (Transco) located in New York (known as Zone 6-NY). After converting both sets of gas prices to electrical energy prices using estimated market heat rates, the Company calculated a combined set of prices that consist of an equal weighing of the two price sets. Market energy prices subsequent to 2012 were then calculated by escalating the 2012 prices at the Consumer Price Index (CPI). As the Company notes in its filing, Zone 6-NY is outside of ISO-NE and, therefore, not a perfect location for approximating the future price of gas to ISO-NE generators. That fact notwithstanding, the Company claims that Zone 6-NY is "the only nearby location traded at NYMEX and generally correlates with basis pricing into New England." Staff disagrees with this claim, noting that significant quantities of natural gas are delivered to New England hubs including Dracut, Massachusetts under NYMEX contracts. Further, 2008 data for Dracut indicate that average prices are lower at Dracut compared to Zone 6-NY by almost $0.60 per Dth. This information suggests that the Company's projection of market energy prices may be higher than it ought to be.

Staff is also concerned about the assumption that market energy prices will increase outside the 5 year planning horizon at the rate of inflation. This assumption is not based on any meaningful analysis and, therefore, is not a reasonable basis on which to conduct investment planning.

Long-term forecasts of wholesale market energy prices are usually developed using a production cost simulation model that takes into account anticipated changes in the key drivers of future prices. The most important drivers for the New England market are: (i) expectations for natural gas prices; (ii) projected growth in the demand for electricity (particularly during peak hours); and (iii) the amount of new generation expected to come on line, net of retirements. Without an in-depth analysis of these and other market drivers, there can be little confidence that the long-term forecast of energy prices is reasonable and provides a sound basis for the revenue requirements analyses.

Finally, Staff questions the reasonableness of the Company's long-term forecast of capacity prices. In the first year following the transition period (2010), the Company assumed the auction clearing price would equal $7.5/kW-month, the levelized cost of a new peaking facility. Thereafter, capacity prices were assumed to escalate at an annual rate of 2.1%. Staff's concern is twofold. First, the

$7.5/kW-month figure has been shown to be not reasonable by the outcome of the first FCA, which resulted in a 2010 price of $4.5/kW-month. This outcome has been attributed to the large amount of new demand resources that cleared in the FCA, a result that was predicted in modeling by the New England Demand Response Initiative.

Second, the assumption that capacity prices will increase after 2011 at the annual rate of 2.1% was not based on any meaningful analysis and, therefore, is of questionable value.

Continued Unit Operation Studies

Q. EARLIER YOU SAID THAT STAFF IS CONCERNED ABOUT THE COMPANY'S FAILURE TO CONDUCT CONTINUED UNIT OPERATION (CUO) STUDIES OF THE MERRIMACK UNITS. WHAT IS A CUO STUDY?

A. A CUO study analyzes the economic value to customers of continuing to operate a unit under expected future market and operating conditions.

Q. WHAT IS THE BACKGROUND TO THIS ISSUE?

A. The background is the Commission's order in Docket DE 04-072, which approved a partial settlement agreement in that docket. The order states in relevant part that PSNH would: (i) discuss and evaluate in its next LCIRP alternatives for complying with potential state and federal mercury emissions regulations; and (ii) quantify the potential rate impacts of its compliance plan.

As regards the first requirement, PSNH stated that subsequent to the partial settlement, the Legislature enacted 2006 N.H. Laws, Chapter 105 (HB 1673), "AN ACT relative to the reduction of mercury emissions." The result of this law, according to PSNH, is that the Legislature has mandated the installation of a wet flue gas desulphurization system at Merrimack Station and, therefore, no other reasonable alternative is legally available. <u>See</u>, RSA 125-O:11-18 (2006) As regards the second requirement, PSNH states that it is not currently able to quantify the potential rate impact of its mercury compliance plan, that is, the installation of a scrubber at Merrimack. It went on to say that the rate impact will ultimately be determined by the capital cost of the scrubber system and the associated increased O&M costs, less cost savings associated with reduced SO2 emissions.

Q. DOES STAFF AGREE THAT THE LEGISLATURE MANDATED THE INSTALLATION OF A WET FLUE GAS DESULPHURIZATION SYSTEM AT MERRIMACK?

A. No. Even though the Legislature did find that installation of scrubber technology at Merrimack is in the public interest, Staff does not interpret RSA 125-O:11-18 as mandating installation regardless of economics. That is, Staff does not believe that the Legislature intended scrubbers be installed if the resulting production cost is expected to exceed the cost of retiring the plant and replacing the lost output with market purchases.[11]

[11] Note that plant retirement is an alternate way of achieving the mercury emissions reductions.

Q. DOES THE FACT THAT THE COMPANY IS NOT CURRENTLY IN A POSITION TO QUANTIFY THE RATE IMPACT OF ITS MERCURY COMPLIANCE PLAN EXPOSE CUSTOMERS TO SIGNIFICANT COST RISKS?

A. Yes, it does. In response to discovery[12], the Company stated that it "has already begun the scrubber project at Merrimack and has selected a project manager and issued requests for proposals for the major components of the project. Site work is expected to begin toward the end of 2008." Absent CUO studies for the Merrimack units, PSNH runs the risk that the incremental costs to install and operate[13] the scrubber, less SO2 allowance savings, could make Merrimack Station operation uneconomic relative to market purchases. Given the large size of the scrubber capital investment (estimated in 2005 at $250 million) plus the potential for increased operating costs, Staff believes that the prudent approach would be for PSNH to conduct a CUO study for Merrimack prior to making any final commitment to the scrubber project.

Q. IS THERE ALSO A NEED TO CONDUCT A CONTINUED UNIT OPERATION STUDY OF THE NEWINGTON STATION?

A. The Company states in the LCIRP that a recent economic review of Newington operation relative to market purchases indicates customer savings during on-peak hours in the months of January, February, July and August. That conclusion, however, was based on a fuel oil price of $[redacted], which Staff understands to be the cost of fuel oil in inventory. This cost is substantially below the current price

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[12] See Exhibit GRM-4 – PSNH Response to Staff 1-02.

[13] Including replacement power costs if scrubber operation reduces the power output of Merrimack.

of fuel oil, which is approximately $90/bbl for 1% sulfur content. Since historic prices have no place an economic analysis of future operations, Staff recommends that PSNH conduct a CUO study for the Newington Station that is based on the forward price of fuel oil.[14]

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

[14] If PSNH anticipates utilizing natural gas at Newington, the appropriate price to use in the study would be the forward price for natural gas at Dracut.