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The Northeast Utilities System

ORIGINAL
N.H.P.U.C. Case No. DG 09-180
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March 28, 2008

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: PSNH Least Cost Integrated Resource Plan
Docket No. DE 07-108

Dear Secretary Howland:

On March 4 and March 11, 2008, representatives from the Staff, the Office of Consumer Advocate, the Interveners, and representatives from Public Service Company of New Hampshire (PSNH) met in two technical sessions to discuss the filing made by PSNH on September 28, 2007. These representatives agreed that PSNH would supplement its filing in three areas: Demand Side Management, Supplemental Power Procurement Strategy, and New Generation Supply Options. Enclosed herein are seven copies of the following supplements:

Supplement 1 – Insert Section IV.H. – Demand-Side Management Conclusion, at page 70.
Supplement 2 – Replace Section VIII.D.1 – Energy Efficiency and Demand-Side Management Programs, at page 105.
Supplement 3 – Append at the end of Section V.B.6.2 – Supplemental Power Procurement Strategy, at page 91.
Supplement 4 – Append at the end of Section V.B.7 – New Generation Supply Options, at page 93.

No other dates for discovery on the Least Cost Plan or for further technical sessions have been decided; however, the Parties will discuss further a procedural schedule after review of these supplements. Electronic copies have been provided to the Office of Consumer Advocate and the persons on the attached service list pursuant to Puc§ 203.02 .

Very truly yours,

Terrance J. Large

Terrance J. Large, Director
Business Planning and
Customer Support Services

Enclosure
cc: Service List

Supplement 3 - Supplemental Power Procurement Strategy

Append the following to the end of Section V.B.6.2, page 91

The following discussion provides an overview of the procurement strategy that PSNH implemented for its 2007 supplemental power requirement. This overview is indicative of PSNH's current procurement strategy; however, as discussed below, PSNH does not have a prescriptive hedging protocol. By retaining flexibility in its planning process, PSNH is able to respond to changes in planning criteria and create benefits for customers.

PSNH forecasted a 2007 supplemental purchase requirement of 2,836 GWh[1]. The development of that forecasted requirement is explained in Section III.C. Based on this forecast, approximately 67 percent of PSNH's energy service requirement was satisfied with owned-generation, IPP production, and the Vermont Yankee entitlement purchase. The remaining 33 percent was the supplemental requirement that was served via market purchases. Of this 33 percent, approximately 9 percent was related to an allowance for unplanned outages at Merrimack and Schiller Stations. Due to the unpredictable timing of unplanned outages, PSNH does not purchase power in advance to hedge this exposure, but rather evaluates the need for replacement power when an actual outage occurs[2]. Therefore, PSNH's initial assessment of market exposure suitable for potential hedging activity was approximately 2,069 GWh (24 percent of forecast energy requirement). This amount is comprised of 1,308 GWh of on-peak exposure and 761 GWh of off-peak exposure.

As discussed in Section V.B.6.1 and Section III.C.2.1, PSNH must manage the variability in energy requirement that is associated with customer migration. As noted above, PSNH elected to hedge a portion of the forecasted supplemental requirement (i.e. the 2,069 GWh) using an energy call option. This option provided a fixed-price source of energy for approximately 490 GWh. Therefore, the residual forecasted quantity of power exposed to market price uncertainty was 1,579 GWh. This amount is comprised of 967 GWh of on-peak exposure and 612 GWh of off-peak exposure.

As detailed in the November 17, 2006 Default Energy Service rate filing in DE 06-125 (Attachment RAB-2, page 3), PSNH ultimately entered into fixed price contracts for 1,699 GWh of energy. The majority of this energy was from firm bilateral strip purchases that delivered the same quantity of energy in each hour of the contract. Since PSNH's actual energy deficiency (i.e. the 2,069 GWh) involved significant hour-by-hour variation, the bilateral strip purchases resulted in occasional hours of surplus sales into the ISO New England spot market. As shown on the aforementioned Attachment RAB-2, approximately 130 GWh of surplus sales were forecasted. Subtracting the forecast surplus sales (130 GWh) from the contracted quantity (1,699 GWh) leaves a net purchase quantity of 1,569 GWh, which is nearly identical to the forecasted exposure of 1,579 GWh.

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[1] For additional details, refer to Attachment RAB-2, page 3 to PSNH's November 17, 2006 Default Energy Service rate filing in DE 06-125

[2] For additional details, refer to the prepared testimony of Richard C. Labrecque in PSNH's September 7, 2007 Proposed Default Energy Service rate filing in DE 07-096

The 1,699 GWh of executed contracts includes the following elements:

- 76 GWh from an IPP buyout replacement contract was executed in 2002
- 1,502 GWh of firm bilateral strip purchases of which 1,130 GWh are multi-month deals and 372 GWh are single-month deals
- 121 GWh from a unit-contingent, fixed-price purchase from an IPP, executed in September 2006

The 1,502 GWh of firm bilateral strip purchases includes the following:

- 930 GWh of on-peak energy
- 572 GWh of off-peak energy

The timing of the 1,502 GWh of firm bilateral strip purchases was as follows:

- 20 percent was executed less than 6 months prior to contract delivery date
- 46 percent was executed between 6 and 9 months prior to contract delivery date
- 17 percent was executed between 9 and 12 months prior to contract delivery date
- 16 percent was executed greater than 12 months prior to contract delivery date
- 0 percent was executed greater than 15 months prior to contract delivery date

The above summary of 2007 activity provides a specific example of the general hedging strategy described in this plan. However, a similar review of activity performed in advance of 2008 would yield somewhat different statistics, although fundamentally similar and consistent with the general plan described herein.

As discussed above, PSNH does not have a prescribed hedging strategy (i.e. a plan that establishes specific dates, quantities, products, terms, etc). PSNH has the infrastructure, staff, and experience to enable a flexible approach to power supply planning. PSNH has retained over 1,100 MW of owned generation. PSNH and Northeast Utilities staff submits daily generation offers and optimizes the dispatch of these assets within the ISO New England markets. Staffers also analyze the ISO New England markets, interface with other market participants, are involved in numerous ISO New England committees and task forces, reconcile settlement accounts with ISO New England, and otherwise perform all the duties required to serve full requirements energy service within the New England market structure. This is in contrast to numerous other distribution companies that have restructured, divested generation, and no longer have the appropriate staff to perform the functions of a load serving entity such as PSNH. Additionally, most or all of these distribution companies have specific solicitation schedules prescribed by the applicable regulatory agency.

PSNH is in a unique position that affords its customers numerous optimization tools that are not available to companies that are only permitted to procure full requirements service via wholesale solicitations from for-profit wholesale suppliers. To optimize the energy service power supply, PSNH continuously forecasts, monitors, and makes adjustments for a number of critical factors, including operational and maintenance schedules at its generation facilities, fuel purchasing decisions, customer load forecasting, migration uncertainty, supplemental power purchasing decisions, and management of the renewable portfolio supply obligation. PSNH also must forecast and settle various ISO New England administrative charges.

Regarding energy purchase decisions (e.g. timing and quantity), PSNH follows a general approach that is both described herein and illustrated by the 2007 activity. To date, most purchasing activity has been focused on the subsequent calendar year. However, PSNH is continuously in the market and has frequent interaction with other participants regarding both short-term (less than one year) and long-term purchase power agreements. PSNH has staff that continuously follows the commodity markets and has full and immediate access to hedging products, either through direct negotiation with other participants or by using standardized products transacted via an energy broker. PSNH and Northeast Utilities staff receives multiple sources of commodity market intelligence on a daily basis from a number of investment banks. Power supply planning staff, generation staff, and fuel purchasing staff communicate as needed to discuss changes in planning assumptions. PSNH is equipped with all the necessary information and tools to execute a flexible purchase strategy.

Supplement 4 – New Generation Supply Options

Append the following to the end of Section V.B.7, page 93

PSNH has proposed the addition of a little more than 250 MW of new generating capability to its system through this plan. This addition falls short of the total capacity and energy needs as depicted in Exhibits VIII-3 and VIII-4 if PSNH were to meets its customers' requirements solely through operation of owned assets. PSNH's proposal to add the diversified mix of new resources, defined herein, is our best estimate of what could reasonably be achieved within the five year planning window associated with this plan. As additional opportunities or restrictions materialize over the planning horizon, PSNH will consider, on a case by case basis, revisions to the generation addition proposals discussed here.

PSNH is cognizant of its requirement to file a new LCIRP, as early as September 2009. Based upon the success of implementing the actions described in this plan, further, more robust generation addition scenarios may be considered in the future.

PSNH Least Cost Integrated Resource Plan
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Supplement 1 – Demand-Side Management

Append the following to the end of Section IV, page 70

H. Conclusion

The following summarizes the highlights and key conclusions regarding demand-side management resources covered in Section IV:

- Exhibits IV-2 and IV-3 present a series of peak demand and energy saving benchmarks over the planning horizon. These benchmarks forecast a range of outcomes based on the scenarios presented. The charts presented here will serve as a basis for the recommendations developed in Section VIII.D.1.

- The CORE Programs offered today are cost-effective and can provide technical and financial assistance to all classes of customers for any electric energy saving measure. In contrast to the CORE Program filings wherein cost-effectiveness is based on regional and New Hampshire average avoided costs, the cost-effectiveness analyses presented here are based on PSNH's avoided energy, capacity, transmission, and distribution costs.

- PSNH's current and potential demand response program offerings were examined as well as offerings of ISO New England and other third party providers. An analysis of the very successful demand response program offered in Connecticut showed that the program does not pass New Hampshire's cost-effectiveness test over the next three years.

- The Total Resource Cost (TRC) and Rate Impact Method (RIM) cost-effectiveness tests were reviewed. New Hampshire utilities have traditionally used the TRC test to determine cost-effectiveness. As part of this filing, the Commission directed PSNH to study the effects of using the RIM test on the availability of demand-side resources. Measures that pass the TRC lower the overall cost of providing electric service; however, utility revenue losses will create upward pressure on rates for all customers. On the other hand, measures that pass the RIM test lower the utility's revenue requirements more than the amount of revenue loss (and thus offer the potential to lower rates for all customers).

  PSNH's analysis demonstrated that use of the RIM test would dramatically reduce the availability of demand-side resources. Furthermore, if used as the sole screening tool, the RIM test has the potential to pass projects which would fail the TRC and fail projects which are cost effective from a TRC perspective.

The demand-side resource assessment presented in Section IV is further analyzed and recommendations are presented in Section VIII, Integration of Demand-Side and Supply-Side Options.

Supplement 2 – Integration of Demand-Side and Supply-Side Options

Replace Section VIII.D.1, page 105, with the following:

D.1. Energy Efficiency and Demand-Side Management Programs

PSNH proposes to expand implementation of its CORE Energy Efficiency programs, with the expansion funded through a 50 percent increase in the System Benefits Charge. PSNH estimates the expanded programs would reduce the 2012 capacity requirements by 26 MW[1] and reduce energy usage by 97,000 MWh over the 2008-2012 planning period at an annual cost of $7.4 million. This proposal is based on an assessment and balancing of the following considerations:

- Ability to Expand Existing Programs
  Successful expansion of the CORE Programs is dependent on a number of factors. While increased program funding is a necessary first step, the availability of customer funding, management support and efficiency infrastructure are also critical.

  First, consider the issue of customer funding. The CORE Programs provide incentives to motivate customers to install the most efficient lighting, motors, shell measures, etc. However, it's important to note that the CORE Programs pay only a portion of the cost of installing efficiency measures -- customers must have the funds to pay for a substantial portion of the installation. For the typical "retrofit" project, customers pay 50-65 percent of the total cost. For new construction, rebates cover 75 percent of the incremental cost to upgrade to premium efficiency equipment; however, customers must pay the remaining 25 percent of the incremental cost as well as the entire cost of the equivalent standard efficiency equipment. Increasing incentive amounts can reduce the need for customer funds, but it will also reduce the kWh savings for each program dollar spent.

  For commercial and industrial customers, whose facilities provide more than 75 percent of the kilowatt-hour savings for the CORE Programs, the availability of funds will be dependent on obtaining management support. Typically the facilities staff will have had to identify a cost-effective project, and that project will have to successfully compete for limited funding against all of the other projects within the organization. Until the project is approved and budgeted, nothing will move forward – regardless of the level of funding available for program incentives.

  Another critical element is the efficiency infrastructure – the availability of trained personnel and materials to complete projects in a timely fashion. The CORE Programs were introduced June 1, 2002 – one day after they were approved by the Commission, but before contractors and quality assurance personnel could be hired and trained. While all of the program goals established for the initial 19-month CORE Program reporting period were met, it was almost a year before any

[1] The capacity reduction figure is obtained by grossing up the program reductions for losses (8percent) and reserves (14.3percent). This is the same process used by ISO- New England to determine capacity reductions.

significant volume of measures were installed. This delay in implementation was due almost entirely to the time needed to establish the program delivery infrastructure.

In a more recent example, the 2008 CORE Programs Filing demonstrated the importance of working with service providers and recognizing their constraints when expanding the programs. In Commission Order No. 24,814[2], PSNH was directed to transfer $540,000 of SO_2 allowance funds to the Home Energy Assistance Program. This program is delivered through the state's six Community Action Agencies and in order to minimize disruptions in their workforce, it was agreed to phase in the additional funds over a three year period.

In summary, successful expansion of the CORE Programs requires not only more program funding, but it also requires that customers have budgeted for efficiency improvement projects and the infrastructure is in place to do the work. To the extent the economy is in difficult financial times, this will make expansion more difficult.

- <u>Potential for the Installation of Additional Efficiency Measures</u>
  Section IV.A.3 examined the potential for achieving energy reductions through the implementation of efficiency program measures. Specifically, Exhibit IV-4 (page 45) plots a range of outcomes over the planning horizon from doing nothing (see solid blue Baseline) to achieving the results suggested by a 2005 study sponsored by the Northeast Energy Efficiency Partnership (see dashed-blue Economically Unrestrained Potential line). Also plotted on this exhibit are outcomes predicted by continuing to implement efficiency programs at the current funding level of 1.8 mills/kWh and a line depicting estimated results were the funding raised to 3.0 mills/kWh. The line representing the higher funding is suggestive of the results that might be achieved if efficiency programs were funded and fully operational at a level equivalent to the most robust programs in the northeast region (see Expanded SBC Funding line).

  There is a very substantial difference between the outcomes predicted by the Expanded SBC Funding line and the Economically Unrestrained Potential line. The Expanded SBC Funding line forecasts a reduction in 2012 of 2.8 percent from the Baseline, while the Economically Unrestrained Potential line is 19.7 percent below the Baseline. The 2.8 percent reduction suggests the results that might be achieved if PSNH could replicate results equivalent to the best programs currently operational in the northeast while the Economically Unrestrained Potential represents the theoretical maximum energy savings.

  There are many factors that can help account for the difference between the Expanded SBC and Economically Unrestrained Potential lines. The Economically Unrestrained Potential scenario assumes that funding and infrastructure are available to install all cost effective measures. In addition, the Economically Unrestrained Potential scenario achieved its results through a substantial contribution from changes to state building codes, adoption of state product efficiency standards, and stricter code enforcement. None of these assumptions are

[2] Order No. 24,814, December 28, 2007, DE 07-096 Request for Approval of 2008 Energy Service Rate

included in the Expanded SBC scenario. A further consideration is that the Economically Unrestrained Potential scenario is based on a study whereas the Expanded SBC scenario is based on results that have actually been achieved.

- The Rate Impact on Customers
  While the implementation of cost-effective programs will reduce the overall cost of service, all customers will see an increase in their rates and customers not participating in the programs will pay more for their electric service. PSNH is mindful that raising the SBC will inevitably result in some customers paying more for electric service despite the fact that program participants will likely pay less.

- Cost-Effectiveness of the Programs
  Expanding the efficiency programs too rapidly could lead to a situation where there is a surplus of program funds as compared to available customer funding. This could lead to pressure to "spend the money" by increasing incentives or funding marginal projects – in either case reducing the savings achieved for each program dollar spent.

PSNH is not proposing any additional demand response programs at this time. As discussed in Section IV.C, PSNH analyzed a number of demand-side programs; however, none are cost-effective and/or feasible at this time. PSNH will continue to monitor this situation and is prepared to consider implementation of cost-effective demand response programs that would be beneficial for our customers.

In summary, based on the economics alone, energy efficiency is the low-cost way to meet future energy requirements. However, for the reasons discussed herein, it is not possible to achieve the theoretically maximum amount of energy savings from energy efficiency in the near term. Consequently, PSNH is recommending a 50 percent increase in efficiency program funding. This aggressive, but limited program expansion is viewed as an initial step. The planned expansion will be reviewed again in two years at the time of the next Least Cost Integrated Resource Plan filing. At that time progress can be assessed and the expansion proposal can be revised based on actual results.