STATE OF NEW HAMPSHIRE
BEFORE THE PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Reconciliation of Energy Service and Stranded Costs for Calendar Year 2013

DIRECT TESTIMONY OF
FREDERICK B. WHITE

I. INTRODUCTION

Q. Please state your name.

A. My name is Frederick B. White.

Q. Mr. White, please provide your business address and title.

A. My business address is 107 Selden St, Berlin, Connecticut. I am a Supervisor in the Electric Supply department of Northeast Utilities Service Company (NUSCO).

Q. Mr. White, please describe your responsibilities at NUSCO.

A. NUSCO provides centralized administrative services to Northeast Utilities' principal subsidiaries, including Public Service Company of New Hampshire (PSNH), The Connecticut Light and Power Company (CL&P), Western Massachusetts Electric Company (WMECO), and NSTAR. I primarily supervise and provide analytical support required to fulfill the power supply requirement obligations of PSNH, CL&P, and WMECO. For PSNH, this includes the development of Energy Service rates, evaluation of the need to supplement PSNH’s resources for the provision of Energy Service, and PSNH’s acquisition of Financial Transmission Rights (FTR) to manage congestion. For CL&P and WMECO, I assist in the design and execution of the power supply sourcing associated with these companies' versions of energy service. I participate in ISO-NE stakeholder meetings and monitor ISO-NE, NEPOOL, and FERC activities to ensure that our operations are up to date.

II. PURPOSE

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report on how PSNH's generation resources and supplemental purchases were used to meet PSNH's energy and capacity requirements during the period January 1, 2013 through December 31, 2013. As a load-serving entity, PSNH is responsible for having sufficient energy to meet the hourly needs of its customers and is also responsible for its share of the ISO-NE capacity requirement. PSNH is also the default provider of service to customers who for any reason are otherwise without a service provider. PSNH meets its requirements through its owned generation, PURPA-mandated purchases under short term rates and long term rate orders, and through supplemental purchases of energy and capacity from the market. I will also discuss PSNH's participation in the FTR auction process and respond to the PUC's Order No. 25,647 in Docket 13-108 regarding generation dispatch decisions.

III. ENERGY REQUIREMENTS

Q. Please summarize the generation resources that were available to meet PSNH's energy requirements during the period January 1, 2013 through December 31, 2013.

A. Attachment FBW-1 lists the generation resource portfolio PSNH used to meet its customers' energy requirements as of December, 2013. As shown on that Attachment, PSNH's available generation capacity during this time period was about 1,256 MW for the summer months. The portfolio is comprised of the following resource groups: hydroelectric (57 MW from nine stations), coal and wood (576 MW from Merrimack and Schiller Stations), gas/oil (419 MW from Newington and Wyman 4), combustion turbines (83 MW from five units), biomass (59 MW is included as the anticipated ongoing capability from Burgess Biopower, however during the latter part of 2013 intermittent test power was received in varying MW quantities from day to day), wind (3 MW from Lempster), and non-utility generation (33 MW from numerous PURPA-mandated purchases, 10 MW from one IPP buyout replacement contract, and 17 MW from one remaining independent wood-fired power producer).

Q. Please summarize how PSNH's generation resources met PSNH's energy requirements during 2013.

A. Attachment FBW-2 summarizes how PSNH's energy requirements were met and how PSNH's generation resources were utilized by month during peak and off-peak periods. During 2013, 66% of peak energy requirements and 70% of off-peak energy requirements were met with the generation resources listed on FBW-1. The remaining energy needs were met through bilateral or spot market energy purchases.

Q. Was PSNH's generation sufficient to meet PSNH's energy requirements in every month?

A. No. PSNH does not own sufficient generating capability to meet its customers' energy requirements in all hours and, therefore, must purchase a portion of its customers' needs. The purchase requirement changes hourly and can range from zero to a significant portion, depending on the availability of PSNH's resources, the level of demand, the migration of customers to competitive energy service options, and the relative economics of PSNH's generation versus purchase alternatives.

Q. Please summarize how supplemental purchases were used to meet PSNH's energy requirements.

A. Attachment FBW-3 summarizes the purchases made to supplement PSNH's generating resources. Approximately 760 GWh of peak energy were purchased at an average cost of $47.99 per MWh (a total expense of $36.5 million). 546 GWh (72%) were purchased bilaterally at an average cost of $46.21 per MWh (a total expense of $25.2 million). Of that, 358 GWh (47% of total) were procured via fixed-price monthly contracts to address forecasted supplemental requirements and planned unit outages, and 187 GWh (25% of total) were procured via fixed-price shorter term arrangements (e.g. daily, weekly) to address unplanned outages and higher load periods. The remaining 215 GWh (28%) of peak energy were procured via the ISO-NE hourly spot market at an average cost of $52.49 per MWh (a total expense of $11.3 million). (Figures may not add due to rounding.)

Approximately 611 GWh of off-peak energy were purchased at an average cost of $38.54 per MWh (a total expense of $23.6 million). 232 GWh (38%) were purchased bilaterally at an average cost of $42.99 per MWh (a total expense of $10.0 million). Of that, 98 GWh (16% of total) were procured via fixed-price monthly contracts to address forecasted supplemental requirements and planned unit outages, and 134 GWh (22% of total) were procured via fixed-price shorter term arrangements (e.g. daily, weekly) to address unplanned outages and higher load periods. The remaining approximately 379 GWh (62%) of off-peak energy were procured via the ISO-NE hourly spot market at an average cost of $35.83 per MWh (a total expense of $13.6

million). The combined expense for all supplemental energy purchases was $60.1 million. (Figures may not add due to rounding.)

Q. Were there any hours in which PSNH's supply resources exceeded PSNH's energy needs?

A. Yes. Attachment FBW-3 also summarizes the hours in which supply resources, including supplemental bilateral purchases, exceeded energy requirements resulting in sales to the ISO-NE spot market. Approximately 200 GWh of peak energy were sold at an average price of $87.94 (total revenues of $17.6 million). In addition, approximately 256 GWh of off-peak energy were sold at an average price of $75.53 (total revenues of $19.3 million). The combined revenue for all surplus energy sales was $36.9 million.

Q. Please summarize how commodity prices (oil, natural gas, and energy) varied during 2013.

A. Attachment FBW-4 is a chart of the 2013 daily prices for crude oil (West Texas Intermediate), natural gas (delivered to Algonquin Gate), and bilateral energy (peak hours at the Mass. HUB). The chart shows the range of commodity and energy market prices in 2013. The chart also shows the continuing correlation between natural gas prices and energy purchase prices in New England. Note also the dramatic natural gas price spikes during winter months, due to space heating demand and delivery constraints on the natural gas transportation pipeline system, with the price frequently exceeding the price of oil, a phenomenon rarely seen during recent prior winters.

Q. Please summarize the impact of commodity market volatility on the cost of serving PSNH's energy requirement.

A. During 2013, 46% of PSNH's energy requirements were met with coal, wood, and hydro resources. Newington is capable of operating on either residual fuel oil or natural gas. Because of the fuel diversity of PSNH's supply portfolio, PSNH is largely insulated from volatility in the natural gas market. During periods of high and volatile natural gas prices PSNH's resource mix provides price stability, and during periods of low natural gas prices ES load can be served through low priced market purchases while PSNH's resources provide insurance against price increases.

IV. CAPACITY REQUIREMENTS

Q. Please describe the cost impact to PSNH's customers associated with the Forward Capacity Market during 2013.

A. Attachment FBW-5 summarizes PSNH's monthly capacity market activity. Over the course of the year PSNH's capacity market revenues from generation resources (including PSNH-owned assets, non-utility IPPs, and the Hydro-Quebec Interconnection Capacity Credits) exceeded PSNH's capacity market expenses, resulting in a net revenue and credit to ES customers of $1.5 million.

Q. Please summarize the ISO-NE capacity market rules that were in effect during 2013.

A. The capacity market in New England is governed by the Forward Capacity Market (FCM) rules and administered by ISO-NE. ISO-NE conducts Forward Capacity Auctions (FCA), into which capacity resources offer MWs, to "procure" the lowest cost resources necessary to meet the ISO-NE Installed Capacity Requirement and to establish the market value of capacity. The capacity prices established for 2013 were $2.95/kW-month. Additional components of the FCM which occur after the FCAs, including Reconfiguration Auctions and monthly Peak Energy Rent adjustments, result in adjustments to Capacity Supply Obligations, the overall rate paid to capacity, and the rate paid by load for capacity. Resources are paid for providing capacity, and the total payments for capacity resources in each month are charged to ISO-NE load serving entities based on their relative share of the prior year's peak demand.

Q. Please summarize the supply resources that were used to meet PSNH's capacity requirements.

A. During 2013, a total of 377,335 MW-months of capacity qualified for credits in the ISO-NE capacity market (this equates to a monthly average of 31,445 MWs). PSNH was allocated 3.50% (13,223 MW-months) of this capacity obligation. PSNH's supply resources had capacity supply obligations of 14,258 MW-months of capacity; comprised of owned generation (12,369 MW-months), non-utility IPPs (615 MW-months, including Lempster), and Hydro-Quebec Interconnection Capacity Credits (1,275 MW-months). For 2013, PSNH had a net capacity surplus of 1,035 MW-months. (Figures may not add due to rounding.) Attachment FBW-5 provides additional details.

Q. Can you estimate the ES customers' capacity credit associated with PSNH's owned generation resources during 2013?

A. Yes. As noted above, for 2013, PSNH's owned resources provided 12,369 MW-months of capacity to ISO-NE. This created $33.7 million in revenue credited to the Energy Service rate.

V. FINANCIAL TRANSMISSION RIGHTS

Q. What is a Financial Transmission Right (FTR)?

A. An FTR is a financial instrument available to participants seeking to manage congestion cost risk or those wishing to speculate on the difference in congestion costs between two locations. These instruments have been available since the introduction of the ISO-NE Standard Market Design. All FTRs are defined by a MW amount, a source location, and a sink location (e.g. a participant may own 100 MW of FTRs that are sourced at the Merrimack node and sink at the New Hampshire load zone). For each MW of FTR, the owner will receive a credit or a charge from ISO-NE equal to the difference in the congestion component of the hourly LMP between the sink and the source. If the sink location congestion price exceeds the source location price, the FTR will have a positive value, i.e. - a credit to that participant's ISO-NE settlement in that hour. Similarly, if the sink location price is less than the source location price, the owner will be charged the difference.

Q. Please summarize PSNH's participation in the ISO-NE FTR auction process.

A. PSNH participated in these auctions as a method of hedging the congestion price differential between the major fossil stations (Merrimack, Schiller, and Newington) and the New Hampshire load zone for periods and in quantities according to forecasted unit operation. PSNH also procured FTRs to hedge the differential between the source location of bilateral purchases (e.g. the Massachusetts Hub) and the New Hampshire load zone. PSNH's generation resources and bilateral purchases provide an effective hedge against the energy component of the zonal LMP, but they do not guard against a congestion component differential. Therefore, even in an hour in which PSNH had sufficient resources to serve its energy requirement, it would be exposed to potential congestion charges. The purpose of acquiring FTRs is to convert the risk associated with a variable, unknown expense (i.e. the hour-by-hour difference in the applicable LMP congestion component), to a fixed, known expense (i.e. the cost of the FTR); however, not at any cost. The prices bid to acquire FTRs are evaluated against potential congestion cost exposure to achieve a balance between risk coverage and minimizing costs for ES customers. During 2013, PSNH acquired via auction 651 GWh of FTRs for a net revenue of $29,013. Settlement of the FTRs resulted in $518,896 of congestion charges. Thus, managing a portion of PSNH's congestion cost risk with FTRs resulted in an overall Energy Service expense of $489,883. This result was due to significant and unusual congestion costs during September and December, between the MA Hub and generator nodes, respectively, and the NH Load Zone.

Q. Will PSNH continue to participate in the FTR auction process in order to hedge against unpredictable congestion costs?

A. Yes. FTRs serve as an insurance policy against unanticipated congestion costs. PSNH procures FTRs primarily to provide cost certainty and thus reduce risk, rather than to achieve savings. If PSNH did not purchase FTRs and there was a problem on the system that resulted in congestion, the cost could be several times the cost of the FTR. Therefore, it makes sense to continue to purchase FTRs when able to do so at reasonable cost to manage the exposure to congestion costs.

VI. PUC ORDER NO. 25,647 in DOCKET DE 13-108

Q. What was required in Order No. 25,647?

A. On April 8, 2014, in Order No 25,647, the Commission required, among other things, that PSNH include in pre-filed testimony in its next reconciliation docket a detailed explanation of how it makes decisions to dispatch generation units during periods when the units are not economic when compared with the regional electric markets.

Q. Please describe PSNH's approach to dispatch decisions.

A. Decisions to offer a unit into the ISO New England electricity market for economic dispatch or to self-schedule a generating unit must be done prospectively (i.e. - without the benefit of knowing actual energy clearing prices). PSNH compares dispatch costs to forward market prices for energy and natural gas, as well as considers weather and expected Energy Service (ES) load in planning generation operations daily and weekly.

Q. Does the potential exposure of ES load to spot market prices enter into the evaluation?

A. Yes. Based on the expected economic operation of the units, a determination is made regarding the surplus or shortfall position of the portfolio of ES load and resources. If ES load is adequately covered (for next day/week) PSNH will offer generation in a manner which will recover costs and create additional value to be returned to ES customers if ISO-NE dispatches its generating resources; and if ES load is not fully covered (for next day/week) PSNH will either self-schedule generation or offer generation in a manner such that ISO-NE may dispatch its generation, to ensure that ES load is protected against high spot market clearing prices. In conjunction with the above, PSNH will evaluate use of bilateral or spot market purchases when it is anticipated that next day/week prices are lower than generation dispatch costs.

Q. What process is followed when making dispatch decisions?

A. PSNH's bidding and scheduling group interacts with PSNH generation and the fuels purchasing group continuously to exchange information, and planning discussions among a larger group occur at least twice weekly. ISO-NE rules require submittal of generation offers on a daily basis by 10 AM (7 days a week, 365 days per year), for the following operating day. These daily submittals are performed by the bidding and scheduling group.

Q. Are there additional economic considerations in addition to the above?

A. Yes. Additional considerations during the process are to ensure generation availability to reliably operate and be able to minimize ES customer load exposure to potentially volatile spot market clearing prices. During the winter/gas season this has become particularly important given ISO-NE's reliance on natural gas and the constraints on the gas pipeline system, and the resulting volatility of natural gas and electricity prices.

Q. What factors lead to generation during periods when the units are not economic when compared with the regional electric markets.

A. Two more common factors are: 1) generation dispatched when favorable economic conditions are foreseen based on forward market prices and weather forecasts, and then those eventualities do not come to pass; and 2) a unit is on-line and an unfavorable economic period is foreseen, followed closely by another favorable period, and rather than come off line the decision is made to operate throughout the period. Unit reliability may be a factor in this scenario as large mechanical equipment is more reliable in steady state operating conditions, than during stop and start cycling operations.

Q. What factors beyond economics might influence unit operations?

A. In addition to economics, additional considerations for operations include required ISO-NE and environmental testing, fuel inventory management, plant status and operating parameters, and varying weather patterns. ISO-NE requires, for example, testing twice each year during certain periods to demonstrate capability for the capacity market. Environment permits likewise require periodic compliance testing. Regarding coal, wood, and oil inventory management, a balance is sought between inventory turnover rates and ensuring adequate fuel is available for operations, and requires constant logistical coordination among fuel producers, transporters, and the on-site capabilities of fuel management systems. Operational limitations may impact dispatch flexibility in both off-line and on-line states. For example, an on-line condition may exist which requires generation at a certain level to maintain operational status, and/or which upon coming off line would result in unit unavailability in order to complete necessary repairs. And at all times unit operating parameters must be honored: such as, minimum run and down times, notification and start times, start-up costs, minimum and maximum generation levels, ramp rates, etc. Weather forecasts are notoriously changing, sometimes outside required decision time frames. These myriad real world factors at any given time may influence unit operations.

Q. Does that complete your testimony?

A. Yes it does.